2003 Annual Report

Financial Section

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

We are a publicly traded limited partnership (NYSE symbol, "EPD") that was formed in April 1998 to acquire, own, and operate all of the NGL processing and distribution assets of Enterprise Products Company, or EPCO. We conduct all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P., our "Operating Partnership" and its subsidiaries and joint ventures. Our General Partner, Enterprise Products GP, LLC, owns a 2.0% interest in us. Unless the context requires otherwise, references to "we," "us," "our" or the "Company" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P., which includes Enterprise Products Operating L.P. and its subsidiaries.

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and notes beginning on page 52 of this annual report. In addition, the reader should review "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" on page 110 of this annual report for information regarding forward-looking statements made in this discussion and certain risks inherent in our business. Other risks involved in our business are discussed under "*Quantitative and Qualitative Disclosures about Market Risk*" on page 47 of this annual report. Additionally, please see Note 14 titled "*Related Party Transactions*" in the Notes to Consolidated Financial Statements for a discussion of related-party matters.

RECENT DEVELOPMENTS

On December 15, 2003, we and certain of our affiliates, El Paso Corporation and certain of its affiliates ("El Paso"), and GulfTerra Energy Partners, L.P. ("GulfTerra") and certain of its affiliates entered into a series of agreements under which one of our wholly-owned subsidiaries and GulfTerra would merge, with GulfTerra surviving the merger and becoming wholly-owned by us. Formed in 1993, GulfTerra is a publicly traded limited partnership (NYSE symbol, "GTM") that manages a balanced, diversified portfolio of interests and assets relating to the midstream energy sector. Prior to December 15, 2003, El Paso was majority owner 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 some of the most active drilling and development regions in the Gulf of Mexico. GulfTerra also owns interests in five natural gas processing and treating plants located in 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 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 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 seven 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 includes a significant portion of the four contiguous corners of Arizona, Colorado, New Mexico and Utah. These regions, especially the deepwater regions of the Gulf of Mexico, which is one of the United States' fastest growing oil and natural gas producing regions, offer GulfTerra significant growth potential through the acquisition and construction of pipelines, platforms, processing and storage facilities and other energy infrastructure.

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

- *Step One*. On December 15, 2003, we 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, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method and GulfTerra will be a consolidated subsidiary of our company. Step Two of the proposed merger includes the following transactions:
  - El Paso's exchange of its remaining 50% interest in GulfTerra GP for a cash payment by our General Partner of $370 million (which will not be funded or reimbursed by us) and a 9.9% interest in our General Partner, and the subsequent capital contribution by our General partner of that 50% interest in GulfTerra GP to us (without increasing our General Partner's interest in our earnings or cash distributions). This transaction reflects an amendment to our initial agreement whereby El Paso initially agreed to exchange its remaining 50% interest in GulfTerra GP for a 50% interest in our General Partner.
  - Our 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 Enterprise common units, resulting in the issuance of approximately 104.6 million Enterprise common units to GulfTerra unitholders.
- *Step Three*. Immediately after Step Two is completed, we expect 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 we will acquire from El Paso as the South Texas midstream assets.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or grant is approximately $4.0 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 us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in 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 the Company and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions 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 our Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2003. The information in the three steps above has been updated with the most current information available to management as of April 2004.

OUR RESULTS OF OPERATIONS

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. 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. Processing includes our natural gas processing business and 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.

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

We define total segment gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be 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. For additional information regarding our business segments, please read Note 20 on page 102 in our Notes to Consolidated Financial Statements of this annual report.

The following table summarizes our consolidated revenues, costs and expenses, equity in income (loss) of unconsolidated affiliates and operating income for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2003	**2002**	**2001**
Revenues	$5,346,431	$3,584,783	$3,154,369
Operating costs and expenses	5,046,777	3,382,839	2,862,582
Selling, general and administrative costs	37,590	42,890	30,296
Equity in income (loss) of unconsolidated affiliates	(13,960)	35,253	25,358
Operating income	248,104	194,307	286,849

The following table reconciles consolidated operating income to our measurement of total segment gross operating margin for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2003	**2002**	**2001**
Operating income	$ 248,104	$ 194,307	$ 286,849
Adjustments to reconcile operating income to total gross operating margin:			
Depreciation and amortization in operating costs and expenses	115,643	86,028	48,775
Retained lease expense, net in operating costs and expenses	9,094	9,125	10,414
Loss (gain) on sale of assets in operating costs and expenses	(16)	(1)	(390)
Selling, general and administrative costs	37,590	42,890	30,296
Total segment gross operating margin	$ 410,415	$ 332,349	$ 375,944

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railroad tankcars for $1 dollar per year. These subleases (the "retained lease expense" in the previous table) are part of the EPCO Agreement (now referred to as the "Administrative Services Agreement") that we executed with EPCO in connection with our formation in 1998. EPCO holds these items pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. Operating costs and expenses (as shown in the Statements of Consolidated Operations and Comprehensive Income) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the Company. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases. In addition, EPCO has assigned to us the purchase options associated with these leases. For additional information regarding the Administrative Services Agreement and the retained leases, please read Note 14 on page 88 in our Notes to Consolidated Financial Statements of this annual report.

Our gross operating margin amounts by segment were as follows for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2003	**2002**	**2001**
Gross operating margin by segment:			
Pipelines	$ 282,854	$ 214,932	$ 96,569
Fractionation	132,822	129,000	118,610
Processing	30,328	(17,633)	154,989
Octane enhancement (1, 2)	(32,701)	8,569	5,671
Other	(2,888)	(2,519)	105
Total segment gross operating margin	$ 410,415	$ 332,349	$ 375,944

(1) Includes non-cash asset impairment charge of $22.5 million recorded during the third quarter of 2003.
(2) Comparability of the gross operating margin for the Octane Enhancement segment for the periods presented is impacted due to ownership changes in the octane enhancement facility in 2003. Prior to October 1, 2003, our 33.3% ownership interest in this facility was recorded under the equity method of accounting. On September 30, 2003, we increased our ownership interest in this facility to 66.7%. As a result of this increased ownership interest, beginning with the fourth quarter of 2003, the financial results of this facility are now consolidated in our financial statements.

Our significant pipeline throughput, plant production and processing volumetric data were as follows for the periods indicated (on a net basis, taking into account our ownership interests):

	For Year Ended December 31,		
	2003 (1)	**2002** (1)	**2001** (1)
MBPD, Net			
NGL and petrochemical pipelines (2)	1,343	1,352	453
NGL fractionation	227	235	204
Isomerization	77	84	80
Propylene fractionation	57	55	31
Equity NGL production	56	73	63
Octane enhancement	4	5	5
BBtus per day, Net			
Natural gas pipelines	1,032	1,201	1,349
Equivalent MBPD, Net			
NGL, petrochemical and natural gas pipelines (3)	1,615	1,668	808

(1) Volumetric data shown in the table above reflect operating rates of the underlying assets for the periods in which we owned them.
(2) In addition to NGL and petrochemical pipeline volumes, this operating statistic also includes NGL import and export volumes.
(3) Aggregate pipeline volumes are shown on an energy-equivalent basis where 3.8 MMBtus of natural gas throughput are equivalent to one barrel of NGL throughput.

Product and Commodity Price Information

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil, selected NGL and petrochemical products and indicative gas processing gross spreads since the beginning of 2001:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound	Indicative Gas Processing Gross Spread, $/gallon
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(3)
2001										
1st Quarter	$ 7.05	$ 28.77	$ 0.49	$ 0.63	$ 0.70	$ 0.74	$ 0.74	$ 0.23	$ 0.17	$ (0.01)
2nd Quarter	$ 4.65	$ 27.86	$ 0.37	$ 0.50	$ 0.56	$ 0.66	$ 0.63	$ 0.19	$ 0.12	$ 0.08
3rd Quarter	$ 2.90	$ 26.64	$ 0.27	$ 0.41	$ 0.49	$ 0.49	$ 0.56	$ 0.16	$ 0.13	$ 0.14
4th Quarter	$ 2.43	$ 21.04	$ 0.21	$ 0.34	$ 0.40	$ 0.39	$ 0.44	$ 0.18	$ 0.13	$ 0.11
Average	$ 4.26	$ 26.07	$ 0.33	$ 0.47	$ 0.54	$ 0.57	$ 0.59	$ 0.19	$ 0.14	$ 0.08
2002										
1st Quarter	$ 2.34	$ 21.41	$ 0.22	$ 0.30	$ 0.38	$ 0.44	$ 0.47	$ 0.16	$ 0.12	$ 0.12
2nd Quarter	$ 3.38	$ 26.26	$ 0.26	$ 0.40	$ 0.48	$ 0.51	$ 0.58	$ 0.20	$ 0.17	$ 0.10
3rd Quarter	$ 3.16	$ 28.30	$ 0.26	$ 0.42	$ 0.52	$ 0.58	$ 0.61	$ 0.21	$ 0.16	$ 0.14
4th Quarter	$ 3.99	$ 28.33	$ 0.31	$ 0.49	$ 0.60	$ 0.63	$ 0.66	$ 0.20	$ 0.15	$ 0.13
Average	$ 3.22	$ 26.08	$ 0.26	$ 0.40	$ 0.50	$ 0.54	$ 0.58	$ 0.20	$ 0.15	$ 0.12
2003										
1st Quarter	$ 6.58	$ 34.12	$ 0.43	$ 0.65	$ 0.76	$ 0.80	$ 0.85	$ 0.24	$ 0.21	$ 0.05
2nd Quarter	$ 5.40	$ 29.04	$ 0.39	$ 0.53	$ 0.58	$ 0.62	$ 0.65	$ 0.25	$ 0.19	$ 0.04
3rd Quarter	$ 4.97	$ 30.21	$ 0.37	$ 0.56	$ 0.67	$ 0.68	$ 0.73	$ 0.21	$ 0.15	$ 0.10
4th Quarter	$ 4.58	$ 31.18	$ 0.40	$ 0.58	$ 0.73	$ 0.71	$ 0.75	$ 0.22	$ 0.16	$ 0.17
Average	$ 5.38	$ 31.14	$ 0.40	$ 0.58	$ 0.68	$ 0.70	$ 0.74	$ 0.23	$ 0.18	$ 0.09

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including OPIS and CMAI. Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents an average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.

(2) Crude oil price is representative of an index price for West Texas Intermediate.

(3) The Indicative Gas Processing Gross Spread is a relative measure used by the NGL industry as an indicator of the gross economic benefit derived from extracting NGLs from natural gas production on the U.S. Gulf Coast. Specifically, it is the amount that the economic value of a composite gallon of NGLs exceeds the value of the equivalent amount of energy of natural gas based on NGL and natural gas prices on the U.S. Gulf Coast. It is assumed that a gallon of NGLs is comprised of 33% ethane, 32% propane, 11% normal butane, 8% isobutane and 16% natural gasoline. The value of a composite gallon of NGLs is determined by multiplying these component percentages by industry index prices listed in the table above. The value of the equivalent amount of energy of natural gas to one gallon of NGLs is 8.9% of the price of a MMBtu of natural gas. The Indicative Gas Processing Gross Spread does not consider the operating and fuel costs incurred by a natural gas processing plant to extract the NGLs nor the transportation and fractionation costs to deliver the NGLs and natural gas to market.

Year ended December 31, 2003 compared to year ended December 31, 2002

Revenues for 2003 increased $1.8 billion over those recorded during 2002. Likewise, costs and expenses increased $1.7 billion over those of 2002. The increase in revenues and costs and expenses is primarily due to higher product sales and purchase prices and the financial results of business acquisitions, both of which offset the effect of lower volumes at some of our pipelines and facilities. In addition, costs and expenses for 2002 includes a $51.3 million loss related to commodity hedging activities.

In general, higher market prices result in increased revenues from our various marketing activities; however, these same higher prices also increase our cost of sales within these activities as feedstock and other purchase prices rise. In addition, higher natural gas market prices during 2003 increased energy-related costs for many of our businesses versus the same period in 2002. The weighted-average market price of NGLs was 57 CPG during 2003 versus 41 CPG during 2002. The market price of natural gas averaged $5.38 per MMBtu during 2003 versus $3.22 per MMBtu during 2002.

When compared to 2002, volumes at some of our downstream pipelines and facilities were lower due to a combination of (i) decreased demand for NGLs, principally ethane, by the ethylene segment of the petrochemical industry (the "ethylene industry") and (ii) lower NGL extraction rates at domestic gas processing facilities. The most significant determinant of the relative economic value of NGLs is demand by the ethylene industry for use in manufacturing plastics and chemicals. During 2003, this industry operated at lower utilization rates when compared to 2002 primarily due to a recession in the domestic manufacturing sector. Also during 2003, as a result of the higher relative cost of NGLs to crude-based alternatives such as naphtha, the ethylene industry utilized crude-based feedstock alternatives in greater quantities than during 2002. The resulting weaker demand for NGLs by this industry limited the ability of NGL producers to sell at higher product prices, which in turn resulted in decreased NGL extraction rates during 2003. For information regarding our outlook for NGL demand by the petrochemical industry, please read "*– Our results of operations – General outlook for 2004*" on page 28 of this annual report.

Equity earnings from unconsolidated affiliates decreased $49.2 million year-to-year primarily due to a $36.4 million decrease in equity earnings from BEF. The $36.4 million decrease in equity earnings from BEF is primarily due to a $22.5 million asset impairment charge we recorded during the third quarter of 2003; increased facility downtime during 2003 for maintenance and economic reasons; and an overall decrease in MTBE sales margins. In addition to lower earnings from BEF, approximately $4.8 million of the overall decrease in equity earnings is due to a rate case settlement recorded by Starfish in 2002.

As a result of items noted in the previous paragraphs, operating income for 2003 increased $53.8 million from that posted during 2002. Total segment gross operating margin increased $78.1 million year-to-year due to the same general reasons underlying the increase in operating income. Operating income includes costs such as depreciation and amortization and selling, general and administrative expenses that are excluded from the non-GAAP financial measure of total segment gross operating margin.

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

Pipelines. Gross operating margin from our Pipelines segment was $282.9 million for 2003 compared to $214.9 million during 2002. On an energy-equivalent basis, net pipeline throughput was 1,615 MBPD during the 2003 period versus 1,668 MBPD during the 2002 period. The increase in gross operating margin was primarily due to our acquisition of Mid-America and Seminole. These two systems earned gross operating margin of $156.3 million during 2003 on aggregate net volumes of 774 MBPD. Since we acquired interests in these systems at the end of July 2002, the 2002 period includes $81.1 million in gross operating margin for August through December 2002. When compared to their historical operating rates, net pipeline transportation volumes on the Mid-America and Seminole systems recorded for 2003 were lower than those reported by these systems for the full year of 2002 primarily due to decreased demand for NGLs, principally ethane, by the ethylene industry and lower NGL extraction rates at regional gas processing facilities.

Excluding the contributions of Mid-America and Seminole, gross operating margin for the Pipelines segment was $126.6 million for 2003 versus $133.8 million for 2002. On an energy-equivalent basis (excluding Mid-America and Seminole), net pipeline throughput volumes increased to 841 MBPD during 2003 from 825 MBPD during the 2002 period. An increase in gross operating margins from our Houston Ship Channel NGL import terminal (and related HSC pipeline), the Lou-Tex NGL and Lou-Tex Propylene pipelines and our recently acquired Port Neches Pipeline partially offset a net decline in our other Gulf Coast area pipeline operations (due in part to lower NGL extraction rates at regional gas processing facilities and demand for NGLs by industry); a $4.8 million decrease in equity earnings from Starfish related to the settlement of a rate case in 2002; and a $4.1 million decrease in gross operating margins from our NGL and petrochemical storage operations due in part to higher energy-related costs and net charges associated with the measurement of liquids volumes held in storage. The 16 MBPD increase in net volumes was primarily due to higher throughput rates at our NGL import terminal (and related HSC pipeline).

Fractionation. Gross operating margin from our Fractionation segment was $132.8 million for 2003 compared to $129.0 million for 2002. Gross operating margin from NGL fractionation improved $10.6 million year-to-year. Net NGL fractionation volumes decreased to 227 MBPD during 2003 from 235 MBPD during 2002. The increase in NGL fractionation gross operating margin is primarily due to (i) mixed NGL measurement gains we recognized during 2003 at our Mont Belvieu facility and (ii) higher percent-of-liquids revenues during 2003 at Norco attributable to the general increase in NGL prices, both of which more than offset a decline in gross operating margin from our other NGL fractionation facilities generally due to lower volumes and higher energy-related costs. The decrease in NGL fractionation volumes period-to-period was primarily due to lower NGL extraction rates at gas processing facilities and reduced demand for NGLs by the petrochemical industry.

Gross operating margin from propylene fractionation declined $9.2 million year-to-year primarily due to lower petrochemical marketing margins resulting from higher feedstock and energy-related operating costs. Net propylene fractionation volumes were 57 MBPD for 2003 compared to 55 MBPD during 2002.

Gross operating margin from isomerization increased $4.5 million year-to-year. Isomerization volumes were 77 MBPD during the 2003 period compared to 84 MBPD during the 2002 period. The increase in gross operating margin from isomerization was generally attributable to higher isomerization fees and by-product revenues, which were partially offset by lower volumes and higher energy-related operating costs.

Processing. Gross operating margin from our Processing segment was $30.3 million for 2003 compared to a gross operating margin loss of $17.6 million in 2002. Our results for 2002 include $51.3 million in commodity hedging losses, the underlying strategies of which were discontinued in 2002. Our commodity hedging results for 2003 were a loss of $0.2 million.

Equity NGL production at our gas processing plants averaged 56 MBPD during 2003 compared to 73 MBPD during 2002. The decrease in equity NGL production year-to-year was largely attributable to reduced demand for NGLs, principally ethane, by the ethylene industry and higher natural gas prices relative to NGL prices, which caused most natural gas processors to minimize the amount of NGLs extracted at their facilities. To meet the natural gas processing needs of Shell (our largest natural gas processing customer) in this challenging business environment, we renegotiated certain provisions of the 20-year Shell natural gas processing agreement during the first quarter of 2003. For a general discussion of this amendment, please read Note 14 on page 87 in the Notes to Consolidated Financial Statements in this annual report.

During 2003, we renegotiated a number of our natural gas processing contracts. In general, our objective has been to convert our traditional keepwhole arrangements to either margin-band/keepwhole contracts (such as the Shell agreement referenced in the preceding paragraph), percent-of-liquids contracts or fee-based contracts. The goal of these renegotiations is to minimize our direct exposure to the volatility of natural gas prices, especially to the extent it increases the PTR cost we would pay under traditional keepwhole arrangements to the point that processing natural gas to extract NGLs becomes uneconomical for us. When NGL extraction is uneconomical, NGLs are left in the natural gas stream to the extent allowed while keeping the natural gas in compliance with pipeline quality specifications; thus reducing the amount of NGLs available for downstream activities such as pipeline transportation and NGL fractionation. For an additional discussion of our current natural gas processing contract mix and an explanation of the various types of contracts we use, please read "*The Company's Operations – Processing*" included under Item 1 in our 2003 Form 10-K filed with the Securities and Exchange Commission.

Octane enhancement. Our equity and consolidated earnings from BEF were a loss of $32.7 million for 2003 compared to equity income of $8.6 million during 2002. Net MTBE production from this facility decreased to 4 MBPD during 2003 versus 5 MBPD during 2002. The $41.3 million decrease in equity earnings is primarily due to a $22.5 million impairment charge we recorded during the third quarter of 2003 for our share of an impairment charge recorded by BEF; increased downtime during 2003 for maintenance and economic reasons; and an overall decrease in MTBE sales margins.

BEF owns a facility that currently produces MTBE, a motor gasoline additive that enhances octane and is used in reformulated gasoline. The production of MTBE is primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990. 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.

As a result of declining domestic demand and a prolonged period of weak MTBE production economics, several of BEF's competitors have announced their withdrawal from the marketplace. 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 BEF recording a non-cash impairment charge of $67.5 million.

BEF's assets were written down during the third quarter of 2003 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 future courses of action being taken (or contemplated to be taken) by BEF management, including the production of iso-octane and alkylate. If the underlying assumptions in the fair value analysis change, resulting in the present value of expected future cash flows being less than the new carrying value of the facility, additional impairment charges may result in the future.

BEF is currently in the process of preparing detailed engineering plans to modify the facility to iso-octane production. 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 to produce alkylate.

Upon our acquisition of an additional 33.3% partnership interest in BEF, it became a majority-owned consolidated subsidiary of ours on September 30, 2003. Historically, BEF was accounted for as an equity-method unconsolidated affiliate. Its results will continue to be reported under our Octane Enhancement segment. For information regarding uncertainties surrounding our investment in BEF, please read " *– Other Items -Uncertainties regarding our investment in facilities that produce MTBE*" beginning on page 45 of this annual report.

Selling, general and administrative costs. These expenses were $37.6 million for 2003 compared to $42.9 million during 2002. The 2002 period includes approximately $10.0 million that we paid to Williams for transition services associated with our acquisition of Mid-America and Seminole compared to $2.0 million paid in 2003 for these services. These payments ceased in February 2003 when we began operating these two pipeline systems.

Interest expense. Interest expense increased to $140.8 million during 2003 from $101.6 million in 2002. The increase is primarily due to additional debt we incurred as a result of business acquisitions. Our weighted-average debt principal outstanding was $2.0 billion during 2003 compared to $1.8 billion during 2002.

Interest expense for 2003 includes $11.3 million of loan cost amortization related to the 364-Day Term Loan, which was incurred in July 2002 and fully repaid in February 2003. For additional information regarding our debt obligations and changes in our debt obligations since December 31, 2002, please read " *– Our liquidity and capital resources – Our debt obligations*" on page 34 of this annual report.

Year ended December 31, 2002 compared to year ended December 31, 2001

Revenues for 2002 increased $430.4 million over those for 2001. The increase is primarily due to the financial results of acquired businesses during 2002 such as the purchase of Mid-America and Seminole from Williams and propylene fractionation and NGL and petrochemical storage assets from Diamond-Koch. Costs and expenses increased $533.4 million year-to-year primarily due to the addition of costs and expenses of acquired businesses and an unfavorable change in results from our commodity hedging activities. Operating income decreased $93.1 million and gross operating margin decreased $43.6 million primarily as a result of such changes.

Pipelines. Gross operating margin from our Pipelines segment was $214.9 million for 2002 compared to $96.6 million for 2001. On an energy-equivalent basis, net pipeline throughput volume for 2002 was 1,668 MBPD compared to 809 MBPD during 2001. Our acquisition of the Mid-America and Seminole NGL pipelines in July 2002 accounted for $81.1 million of the improvement in segment gross operating margin and 843 MBPD of the increase in throughput rates. Gross operating margin from our Mont Belvieu storage businesses improved

$17.9 million in 2002 primarily due to the acquisition of Diamond-Koch's storage business in January 2002. Another $10.5 million of the improvement in year-to-year gross operating margin was caused by the inclusion of a full year's results of operations from Acadian Gas in 2002, whereas 2001 included only nine months. We acquired Acadian Gas in April 2001.

Fractionation. Gross operating margin from our Fractionation segment was $129.0 million for 2002 compared to $118.6 million for 2001. We expanded our propylene fractionation business in February 2002 with the acquisition of Splitter III from Diamond-Koch. Our propylene fractionation volumes increased to 55 MBPD during 2002 from 31 MBPD during 2001. Gross operating margin from these businesses increased $22.6 million year-to-year. Splitter III accounted for 25 MBPD of the increase in volumes and $24.7 million of the increase in gross operating margin. Our isomerization business posted a $4.6 million decrease in gross operating margin for 2002 when compared to 2001. Isomerization volumes increased to 84 MBPD during 2002 versus 80 MBPD during 2001. The positive effect of the higher isomerization volumes was offset by a decrease in isomerization revenues. Certain of our isomerization fees are indexed to historical natural gas prices (which were higher in 2001 relative to 2002).

Lastly, gross operating margin from our NGL fractionation businesses decreased $8.1 million in 2002 when compared to 2001. NGL fractionation volumes increased to 235 MBPD during 2002 from 204 MBPD during 2001. The year-to-year decrease in NGL fractionation gross operating margin is primarily due to lower revenues from our Mont Belvieu NGL fractionation facility caused by strong competition at this industry hub, partially offset by the addition of earnings from the Toca-Western facility we acquired in June 2002. Of the 31 MBPD increase in NGL fractionation volumes, 14 MBPD is due to our purchase of an additional 12.5% interest in the Mont Belvieu facility and 9 MBPD is due to the acquisition of Toca-Western.

Processing. Gross operating margin from our Processing segment was a loss of $17.6 million for 2002 compared to income of $155.0 million for 2001. Of the $172.6 million change in gross operating margin, $152.6 million is due to a decrease in results from our commodity hedging activities. We recorded a loss of $51.3 million from these activities during 2002 versus income of $101.3 million during 2001. Also, gross operating margin from NGL marketing activities included in this segment benefited from unusually strong demand for propane and isobutane during early and mid-2001 which did not repeat during 2002. The year-to-year net decline in commodity hedging results and earnings from our NGL marketing activities was partially offset by a favorable decrease in NGL inventory valuation adjustments. Also, gross operating margin for 2001 includes the $10.6 million expense we recorded related to amounts owed to us by Enron, which filed for bankruptcy in December 2001. Our equity NGL production was 73 MBPD during 2002 versus 63 MBPD during 2001. The 10 MBPD increase in equity NGL production rates is primarily due to improved gas processing conditions.

As noted above, the $152.6 million decrease in commodity hedging results was the primary reason for the year-to-year decline in gross operating margin from this segment. In order to manage the risks associated with our Processing segment, we may enter into short-term, highly liquid commodity financial instruments to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. We have employed various hedging strategies to mitigate the effects of fluctuating commodity prices (primarily NGL and natural gas prices) on our earnings from Processing segment businesses.

Beginning in late 2000 and extending through March 2002, a large number of our commodity hedging transactions were based on the historical relationship between natural gas prices and NGL prices. This type of hedging strategy utilized the forward sale of natural gas at a fixed-price with the expected margin on the settlement of the position offsetting or mitigating changes in the anticipated margins on NGL marketing activities and the market values of our equity NGL production. Throughout 2001, this strategy proved very successful (as the price of natural gas declined relative to our fixed positions) and was responsible for most of the $101.3 million in commodity hedging income we recorded during 2001.

In late March 2002, the effectiveness of this strategy was reduced due to an unexpected rapid increase in natural gas prices whereby the loss in the value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. Due to the inherent uncertainty surrounding natural gas prices at the time, we decided that it was prudent to exit this strategy, and we did so by late April 2002. The increased ineffectiveness of this strategy is the primary reason for the $51.3 million in commodity hedging losses recorded during 2002. A variety of factors influence whether or not our hedging strategies are successful. For additional information regarding our financial instrument portfolios, please read "*Quantitative and Qualitative Disclosures About Market Risk*" on page 47 of this report.

Octane Enhancement. Our equity earnings from BEF were $8.6 million for 2002 compared to $5.7 million for 2001. The improvement is primarily due to increased MTBE production attributable to lower maintenance downtime. On a gross basis, BEF's MTBE production increased to 15 MBPD during 2002 compared to 14 MBPD during 2001.

Other. Gross operating margin from this segment decreased $2.6 million year-to-year primarily due to an increase in information technology-related facility support costs.

Selling, general and administrative expenses. These expenses increased to $42.9 million during 2002 compared to $30.3 million during 2001. The increase is primarily due to the additional staff and resources needed to support our expansion activities resulting from acquisitions and other business development. The majority of the additional costs for 2002 are attributable to amounts we paid Williams for transition services associated with our acquisition of Mid-America and Seminole.

Interest expense. Interest expense increased to $101.6 million during 2002 compared to $52.5 million during 2001. The increase is primarily due to debt obligations we incurred as a result of business acquisitions and investments in inventory. Of the $49.1 million increase in interest expense, $21.4 million is attributable to the debt incurred to finance the Mid-America and Seminole acquisitions. In addition, income from our interest rate hedging activities (which is recorded as a reduction in interest expense) decreased $12.3 million in 2002 when compared to 2001. The change in interest rate hedging results is primarily due to certain elections by counterparties during 2001 to terminate interest rate hedging agreements.

General outlook for 2004

We expect our business to be affected by the following key trends and events during 2004. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our expectations may vary materially from actual results.

- As noted earlier, the most significant determinant of the relative economic value of NGLs is demand by the ethylene industry for use in manufacturing plastics and chemicals. During 2003, this industry operated at lower utilization rates when compared to 2002 primarily due to a recession in the domestic manufacturing sector. As the domestic economy began to strengthen during the third and fourth quarters of 2003, NGL demand by the ethylene industry increased, but remained below the five-year average for these products.

  As we begin 2004, we are encouraged by further improvement in demand for NGLs by the ethylene industry. We have received indications from many of our largest NGL consuming customers that their operating rates and demand for NGLs should be greater in 2004 than 2003 based on the demand for their products and the prospects of a further strengthening in the domestic and global economies. If our expectations regarding demand for NGLs by the ethylene industry are met and natural gas prices remain stable, we should realize improved operating rates at many of our facilities and pipelines.

- Our overall results of operations and financial position during 2004 will be affected by the timing and successful completion of our proposed merger with GulfTerra.

  The assets of the proposed combined partnership would include over 30,000 miles of pipelines comprised of over 17,000 miles of natural gas pipelines, 13,000 miles of NGL pipelines and 340 miles of offshore Gulf of Mexico large capacity crude oil pipelines. The combined partnership's other logistical assets would also include ownership interests in 164 MMBbls of NGL storage capacity and 23 Bcf of natural gas storage capacity, seven offshore Gulf of Mexico hub platforms, and import and export terminals on the Houston Ship Channel. The combined partnership would also own interests in 19 fractionation plants with a net capacity 650 MBPD and 24 natural gas processing plants with a net capacity of 6.0 Bcf/d.

We believe the assets and businesses of these two partnerships are complementary. We believe the scale and business opportunities for the combined partnership would provide us with a number of avenues to create value for our unitholders and our producing and consuming customers.

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 Enterprise and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions to the merger will be satisfied, we expect to complete the merger in the second half of 2004. For additional information regarding the proposed merger, please read " – *Recent Developments*" on page 19 of this annual report.

- As a result of our acquisition of a 50% interest in GulfTerra GP in December 2003, our equity earnings from this investment will increase earnings from the Pipelines segment and increase cash distributions from unconsolidated affiliates. This acquisition is Step One of our proposed merger with GulfTerra. For additional information regarding the proposed merger with GulfTerra, please read " – *Recent Developments*" on page 19 of this annual report. During February 2004, we received the first quarterly cash distribution from GulfTerra GP, which was approximately $10.6 million. Future distributions and earnings from GulfTerra GP will be dependent on the declared distribution rates and operating results of GulfTerra.

- Earnings from our Octane Enhancement business will continue to be subject to MTBE sales margins until our iso-octane project is completed. Several states, including California, New York and Connecticut, implemented MTBE bans on January 1, 2004. Although these bans have weakened overall demand for MTBE, several MTBE suppliers exited the industry during 2003. The reduced supply for MTBE during 2004 should help to stabilize prices over the short-term while we work to convert the facility to iso-octane production.

  We are currently in the process of modifying BEF's MTBE production facility to produce iso-octane, a motor gasoline octane enhancement additive derived from isobutane. We expect iso-octane demand by refiners to replace octane volume that is lost as a result of MTBE being eliminated as a motor gasoline blendstock. Our modification project is expected to be complete during the third quarter of 2004. 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. Our isomerization rates related to BEF will depend on the extent that MTBE and iso-octane are produced (both products use isobutane as a feedstock). For additional information regarding our Octane Enhancement business including regulatory and environmental matters, please read "*The Company's Operations – Octane Enhancement*" included under Item 1 in our Form 10-K for 2003.

OUR LIQUIDITY AND CAPITAL RESOURCES

General

Our primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures (both sustaining and expansion-related), business acquisitions and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources including (either separately or in combination) cash flows from operating activities, borrowings under commercial bank credit facilities, the issuance of additional partnership equity and public or private placement debt. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

As noted above, certain of our liquidity and capital resource requirements are fulfilled by borrowings made under debt agreements and/or proceeds from the issuance of additional partnership equity. At December 31, 2003, we had approximately $2.1 billion in principal outstanding under various debt agreements. On that date, total borrowing capacity under our revolving commercial bank credit facilities was $500 million of which $315 million was unused. For additional information regarding our debt, please read " – *Our debt obligations*" on page 34 of this annual report.

In February 2001, we filed a universal shelf registration with the SEC covering the issuance of up to $500 million of partnership equity or public debt obligations. In October 2002, we sold 9,800,000 common units under this shelf registration statement which generated $182.5 million of cash to us (including related capital contributions from our General Partner). In January 2003, we sold an additional 14,662,500 common units under this shelf registration which generated $258.1 million of cash to us (including related capital contributions from our General Partner). We used the cash generated by these equity offerings to reduce debt outstanding under our 364-Day Term Loan and for working capital purposes. Also, in January and February 2003, we issued Senior Notes C ($350 million principal amount) and Senior Notes D ($500 million principal amount), respectively. For information regarding our application of cash obtained through these debt offerings, please read " – *Our debt obligations*" on page 34 of this annual report.

In January 2003, we filed a new $1.5 billion universal shelf registration statement with the SEC covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). In June 2003, we sold 11,960,000 common units under this shelf registration statement, which generated $261.1 million of cash to us (including related capital contributions from our General Partner). We used the cash generated by this equity offering to reduce debt outstanding under our revolving credit facilities. As a result of meeting certain financial tests, the Subordination Period (as defined in our partnership agreement), with respect to our subordinated units, ended on August 1, 2003. With the expiration of the Subordination Period, we may prudently issue an unlimited number of units for general partnership purposes.

In July 2003, we filed a registration statement with the SEC covering our Distribution Reinvestment Plan (the "DRP"). The DRP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional common units. Currently, the registration statement covers the issuance of up to 5,000,000 common units under the DRP. As a result of reinvestment proceeds from our limited partners under the DRP, our General Partner will be required to make cash capital contributions to us in order to maintain its ownership interest. We expect to use the cash generated from this reinvestment program for general partnership purposes.

Initial reinvestments under the DRP occurred in August 2003. For all of 2003, we issued 2,883,803 common units in connection with the DRP and received proceeds of approximately $60.3 million. EPCO's reinvestment accounted for approximately $55.0 million of the $60.3 million reinvested during 2003. To support our growth objectives and financial flexibility, EPCO has announced that it expects to reinvest under the DRP an additional $140 million of its cash distributions from the first quarter of 2004 through the first quarter of 2005. As a result, we are preparing to increase the number of common units that can be issued under the DRP to approximately 15,000,000 common units.

In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO for $100 million in a private transaction. Our General Partner contributed approximately $2 million in connection with this offering in order to maintain its ownership interest. We used the net proceeds from this offering to repay $100 million of the debt we incurred to finance our December 2003 purchase of a 50% interest in GulfTerra GP and the remainder for general partnership purposes.

If deemed necessary, we believe that additional financing arrangements can be obtained on reasonable terms. Furthermore, we believe that maintenance of our investment grade credit ratings combined with a continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

The following discussions highlight significant year-to-year comparisons in consolidated operating, investing and financing cash flows:

	For Year Ended December 31,		
	2003	**2002**	**2001**
Net income	$ 104,546	$ 95,500	$ 242,178
Adjustments to reconcile net income to cash flows provided by (used for) operating activities before changes in operating accounts:			
Depreciation and amortization	128,434	94,925	51,903
Equity in income of unconsolidated affiliates	13,960	(35,253)	(25,358)
Distributions received from unconsolidated affiliates	31,882	57,662	45,054
Changes in fair market value of financial instruments	(29)	10,213	(5,697)
Other	25,024	14,059	12,391
Cash flow from operating activities before changes in operating accounts	$ 303,817	$ 237,106	$ 320,471
Net effect of changes in operating accounts	120,888	92,655	(37,143)
Operating activities cash flows	$ 424,705	$ 329,761	$ 283,328

Operating cash flows primarily reflect net income adjusted for depreciation and amortization, equity earnings and cash distributions from unconsolidated affiliates, fluctuations in the fair value of financial instruments and changes in operating accounts. The net effect of changes in operating accounts is generally the result of timing of sales and purchases near the end of each period. Cash flow from operations is primarily based on earnings from our business activities. As a result, these cash flows are exposed to certain risks. The products that we process, sell or transport are principally used as feedstocks in petrochemical manufacturing, in the production of motor gasoline and as fuel for residential, agricultural and commercial heating. Reduced 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 or other reasons, could have a negative impact on our earnings and thus the availability of cash from operating activities. Other risks include fluctuations in NGL and energy prices, competitive practices in the midstream energy industry and the impact of operational and systems risks. For a more complete discussion of these and other risk factors pertinent to our business, please read "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" on page 110 of this annual report.

Year ended December 31, 2003 compared to year ended December 31, 2002

Operating cash flows. Cash flow from operating activities was an inflow of $424.7 million during 2003 compared to an inflow of $329.8 million during 2002. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $303.8 million during 2003 versus $237.1 million during 2002. We believe that cash flow from operating activities before the net effect of changes in operating accounts is an important measure of our ability to generate core cash flows from our assets and other investments. The $66.7 million increase in this element of our cash flows is primarily due to:

- earnings from newly acquired businesses in the 2003 period but not in the 2002 period (particularly those of Mid-America and Seminole, which we acquired in July 2002);
- the 2002 period including $51.3 million of commodity hedging losses versus $0.6 million of such losses during the 2003 period; offset by
- higher interest costs associated with debt we incurred and issued since the first quarter of 2002 to finance acquisitions.

The $33.5 million increase in depreciation and amortization is primarily due to additional businesses acquired since the first quarter of 2002. The net effect of changes in operating accounts is generally the result of timing of cash receipts from sales and cash payments for inventory, purchases and other expenses near the end of each period. For additional information regarding changes in operating accounts, please read Note 17 of the Notes to Consolidated Financial Statements on page 96 of this annual report.

Investing cash flows. During 2003, we used $657.0 million in cash for investing activities compared to $1.7 billion during 2002. We used $37.3 million and $1.6 billion for business acquisitions during 2003 and 2002, respectively. The 2002 period reflects our acquisition of interests in the Mid-America and Seminole pipelines from Williams and propylene fractionation and NGL and petrochemical storage assets from Diamond-Koch. The 2003 period includes only minor acquisitions, specifically the Port Neches pipeline and additional interests in EPIK, BEF, Wilprise and OTC.

Investments in and advances to unconsolidated affiliates increased to $471.9 million during 2003 compared to $13.7 million during 2002. The 2003 period includes our payment of $425 million to El Paso for a 50% ownership interest in the general partner of GulfTerra in December 2003. The remaining $33.2 million year-to-year increase is primarily due to funding our share of the expansion projects of our Gulf of Mexico natural gas pipeline investments and our purchase of an additional interest in Tri-States.

Our capital expenditures were $145.9 million during 2003 versus $72.1 million during 2002. The $73.8 million increase in capital expenditures is primarily due to expansions of our Norco NGL fractionator and Neptune gas processing facility.

Financing cash flows. Our financing activities were a cash inflow of $248.9 million during 2003 compared to an inflow of $1.3 billion during 2002. During 2003, we made net payments on our debt obligations of $106.8 million. Our borrowings during 2003 include the issuance of Senior Notes C ($350 million in principal amount), Senior Notes D ($500 million in principal amount) and the $425 million borrowing under the Interim Term Loan (to purchase a 50% interest in the general partner of GulfTerra). Our repayments during 2003 include the use of proceeds from equity offerings completed in January, June, August and December. The 2002 period primarily reflects borrowings to fund the Mid-America and Seminole acquisitions and those of Diamond-Koch's propylene fractionation business.

Proceeds from our common unit and Class B special unit equity offerings during 2003 totaled $675.7 million, which includes our General Partner's related $7.8 million contribution to us. Our General Partner also contributed $5.9 million to our Operating Partnership in connection with these offerings. Distributions to our partners and minority interests increased to $318.0 million during 2003 from $218.2 million during 2002. The $99.8 million increase in distributions to partners is primarily due to increases in both the declared quarterly distribution rates and the number of units eligible for distributions.

Year ended December 31, 2002 compared to year ended December 31, 2001

Operating cash flows. Cash flow from operating activities was an inflow of $329.8 million during 2002 compared to $283.3 million during 2001. As shown in the preceding table, cash flow before changes in operating accounts was an inflow of $237.1 million during 2002 versus $320.5 million during 2001. The $83.4 million year-to-year decrease in this element of our cash flows is primarily due to net hedging losses in 2002 versus net hedging income in 2001 offset by increased distributions from unconsolidated affiliates and earnings from businesses we acquired during 2002. The $43.0 million increase in depreciation and amortization is primarily due to businesses we acquired during 2002. Changes in operating accounts are generally the result of timing of cash receipts from sales and cash payments for inventory, purchases and other expenses near the end of each period. For additional information regarding changes in operating accounts, please read Note 17 of the Notes to Consolidated Financial Statements included on page 96 of this annual report.

Investing cash flows. During 2002, we used $1.7 billion in cash for investing activities compared to $491.2 million during 2001. Fiscal 2002 reflects $1.6 billion of business acquisitions including $1.2 billion paid to acquire Mid-America and Seminole and $368.7 million paid to acquire Diamond-Koch's Mont Belvieu, Texas propylene fractionation and NGL and petrochemical storage businesses. Fiscal 2001 includes $113.0 million paid to acquire equity interests in four Gulf of Mexico natural gas pipelines from El Paso and $225.7 million paid to acquire Acadian Gas from Shell. During 2002, our capital expenditures were $72.1 million compared to $149.9 million during 2001. The majority of capital expenditures made during both periods were for projects within our Pipelines segment.

Financing cash flows. Our financing activities generated $1.3 billion in cash inflows during 2002 compared to $279.5 million during 2001. Our net borrowings were $1.3 billion in 2002 versus $449.7 million in 2001. The increase in borrowings is primarily due to acquisitions, particularly the $1.2 billion paid for

Mid-America and Seminole and the $239.0 million for Diamond-Koch's propylene fractionation business. The borrowing shown for 2001 reflects the issuance of our Senior Notes B, which was primarily used to finance the acquisition of Acadian Gas, Starfish, Neptune and Nemo.

Financing activities also reflect the net proceeds and related General Partner contributions from our October 2002 issuance of 9,800,000 new common units. Net proceeds from the sale of the common units were $182.5 million. This amount includes the General Partner's aggregate contribution to us and our Operating Partnership of $3.7 million to maintain its combined 2% general partner interest. Cash distributions to our partners and minority interests increased $52.2 million year-to-year primarily due to increases in both the declared quarterly distribution rates and the number of units eligible for distributions. The number of units eligible for distributions was higher in 2002 due to the conversion of 19.0 million of Shell's Class A special units to an equal number of common units in August 2002 and our issuance of the 9.8 million new common units in October 2002. Debt issuance costs increased $16.2 million year-to-year primarily due to the $15.0 million in fees we paid to lenders in July 2002 associated with the short-term financing of the Mid-America and Seminole acquisitions.

Our debt obligations

Our debt consisted of the following at the dates indicated:

	December 31, 2003	December 31, 2002
Borrowings under:		
364-Day Term Loan, variable rate, repaid during 2003 (1)		$ 1,022,000
Interim Term Loan, variable rate, due the earlier of September 2004 or the date that our proposed merger with GulfTerra is completed	$ 225,000	
364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity	70,000	99,000
Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity (2)	115,000	225,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005 (3)	30,000	45,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed rate, due February 2013	350,000	
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	
Total principal amount	2,144,000	2,245,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,531	1,774
Less unamortized discounts on Senior Notes A, B and D	(5,983)	(311)
Subtotal long-term debt	2,139,548	2,246,463
Less current maturities of debt (4)	(240,000)	(15,000)
Long-term debt (4)	$ 1,899,548	$ 2,231,463
Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility (2)	$ 1,300	$ 2,400

(1) We used a combination of proceeds from the issuance of Senior Notes C and D and the October 2002 and January 2003 common unit offerings to fully repay this $1.2 billion 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, borrowings under this facility are not included in current maturities because we have the option and ability to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the agreement.

For scheduled future maturities of long-term debt at December 31, 2003, please read " – *Our contractual obligations*" on page 39 of this annual report.

Parent-subsidiary guarantor relationships

We act as guarantor of all of our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own 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 our $425 million purchase from El Paso of a 50% membership interest in GulfTerra GP. The maturity date of this term loan is the earlier of September 2004 or the date our proposed merger with GulfTerra is completed. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to our General Partner. We have 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 1/2% 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*" on page 36 of this annual report.

This term loan agreement contains various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires us 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 will be prohibited from making distributions to us, which would impair our ability to make distributions to our partners. As defined in the agreement, we 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 our General Partner. We have 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 1/2% or (2) a Eurodollar rate. Whichever base rate we select, the rate is increased by an appropriate applicable margin (as defined within 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*" on page 36 of this annual report.

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 our General Partner. We have 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 1/2% 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*" below.

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 our General Partner. We have 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, we issued $350 million in principal amount of 6.375% fixed-rate senior notes due February 2013 ("Senior Notes C"), from which we 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, we exchanged 100% of the private placement Senior Notes C for publicly registered Senior Notes C.

In February 2003, we issued $500 million in principal amount of 6.875% fixed-rate senior notes due March 2033 ("Senior Notes D"), from which we 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, we 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 our October 2002 equity offering to partially repay this loan. We also used $252.8 million of the $258.1 million in proceeds from the January 2003 equity offering, $347.0 million of the $347.7 million in proceeds from our issuance of Senior Notes C and $421.4 million in proceeds from our 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.

Credit ratings

Our current senior unsecured credit ratings are Baa2 as rated by Moody's Investor Services and BBB- as rated by Standard and Poor's, both are investment grade. On December 15, 2003 as the result of our execution of definitive agreements with GulfTerra and El Paso to merge with GulfTerra, Moody's put our rating under review for possible downgrade and Standard and Poor's placed our rating on credit watch with negative implications. Both debt rating agencies will be reviewing the credit attributes and the risk profile of the merged partnership as well as the execution risk of the permanent financing of the proposed merger.

On November 26, 2003, our senior unsecured credit rating as rated by Standard and Poor's was lowered from BBB to BBB- with a negative outlook. Standard and Poor's indicated that the negative outlook reflected their concern that the rebound in NGL demand was temporary and that weak demand could return in 2004. Standard and Poor's also indicated that our rating was subject to downgrade if our financial performance in 2004 was less than the then current expectations. Standard and Poor's cited concerns regarding our financial performance during the second and third quarters of 2003 and the sustainability of increased NGL demand by the petrochemical industry during 2004. Standard and Poor's indicated that it was also evaluating what effect, if any, that EPCO's purchase of Shell's interest in our General Partner might have on our overall credit quality.

We believe that the maintenance of an investment grade credit rating is important in managing our liquidity and capital resource requirements. We maintain regular communications with these ratings agencies, each of which independently judges our creditworthiness based on a variety of quantitative and qualitative factors.

Capital spending forecasts

At December 31, 2003, we had $4.0 million in estimated outstanding purchase commitments attributable to capital projects, practically all of which were related to the construction of assets that will be recorded as property, plant and equipment. During 2004, we expect capital spending on internal growth projects to approximate $87 million, of which $42 million is projected to be spent on projects within our Pipelines segment and approximately $30 million on the conversion of the MTBE facility to dual use MTBE and iso-octane production. We expect to invest approximately $8 million in the projects of our unconsolidated affiliates during 2004, of which $6 million is attributable to projects of our Gulf of Mexico natural gas pipeline investments.

EPCO subleases to us all of the equipment it holds pursuant to operating leases relating to an isomerization unit, a deisobutanizer tower, a cogeneration unit and approximately 100 railcars for one dollar per year and has assigned to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the lease payments associated with these items. We have notified the original lessor of the isomerization unit of our intent to exercise the purchase option assigned to us. 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.

Pipeline Integrity Management Program

Our NGL, petrochemical and gas pipelines are subject to the pipeline safety program established by the 1996 federal Pipeline Safety Act and its implementing regulations. The U.S. Department of Transportation, through the Office of Pipeline Safety ("OPS"), is responsible for developing, issuing and enforcing regulations relating to the design, construction, inspection, testing, operation, replacement and management of natural gas and hazardous liquid pipelines. In 2001, OPS issued safety regulations containing requirements for the development of integrity management programs for oil pipelines (which includes NGL and petrochemical pipelines such as ours) in certain "high consequence areas." High consequence areas include but are not limited to high population areas, environmentally sensitive locations, and areas containing drinking water supplies. In connection with these regulations, we developed a Pipeline Integrity Management Program and, by the end of 2002, had identified the segments of our liquids pipelines that were located in such areas. The regulations stipulate that a pipeline company must assess the condition of its pipelines in such areas and perform any necessary repairs. We are required to evaluate at least 50% of our identified pipeline mileage in such high consequence areas by the end of 2004 with the balance completed before April 2008. After this initial testing is complete, the identified pipeline segments must be reassessed every five years thereafter.

On November 15, 2002, Congress passed the Pipeline Safety Improvement Act, which contains requirements for the development of integrity management programs on gas pipelines located in certain "high consequence areas," and effective February 14, 2004, OPS adopted regulations to implement this statute. The new regulations require gas pipeline operators to develop by December 17, 2004, integrity management programs for gas transmission pipelines that could impact high consequence areas in the event of a failure. We anticipate that our implementation of the gas pipeline regulations will proceed on a timely basis.

During 2003, we spent approximately $10 million to comply with these new regulations, of which $4.5 million was expensed. During each of the years 2004 through 2008, our cash outlays for this program are expected to be in the range of $12 million to $23 million. At present, we expect that approximately 85% of these future expenditures will be recorded as operating expenses within our Pipelines segment.

OUR CONTRACTUAL OBLIGATIONS

The following table summarizes our contractual obligations at December 31, 2003 (dollars in thousands):

Contractual Obligations	Total	Payment or Settlement due by Period: Less than 1 year	1-3 years	3-5 years	More than 5 years
Time period		(2004)	(2005 – 2006)	(2007 – 2008)	Beyond 2008
Long-term debt, including current maturities (1)	$ 2,144,000	$ 240,000	$ 550,000		$ 1,354,000
Operating lease obligations (2)	$ 47,197	$ 8,928	$ 8,076	$ 7,130	$ 23,063
Purchase obligations: (3)					
Product purchase commitments: (4)					
Estimated payment obligations:					
Natural gas	$ 1,079,876	$ 150,620	$ 233,466	$ 231,930	$ 463,860
NGLs	$ 131,904	$ 15,745	$ 17,870	$ 17,870	$ 80,419
Petrochemicals	$ 1,149,987	$ 425,971	$ 700,345	$ 23,671	
Other	$ 75,455	$ 45,996	$ 23,889	$ 4,414	$ 1,156
Underlying major volume commitments:					
Natural gas (in BBtus)	164,032	23,602	35,310	35,040	70,080
NGLs (in MBbls)	5,333	578	732	732	3,291
Petrochemicals (in MBbls)	36,892	13,696	22,442	754	
Service payment commitments (5)	$ 552	$ 382	$ 170		
Capital expenditure commitment (6)	$ 4,003	$ 4,003			
Other Long-term liabilities, as reflected on our Consolidated Balance Sheet (7)	$ 14,081	$ 860	$ 11,078		$ 2,143

(1) We have long and short-term payment obligations under credit agreements such as our senior notes and revolving credit facilities. Amounts shown in the table represent our scheduled future maturities of long-term debt (including current maturities thereof) for the periods indicated. For additional information regarding our debt obligations, please read " - *Our liquidity and capital resources – Our debt obligations*" on page 34 of this annual report.

(2) We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum lease payment obligations under our third-party operating leases with terms in excess of one year for the periods indicated.

(3) We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions.

(4) 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. Amounts shown in the table represent our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2003 applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery.

(5) 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 shows our future payment obligations under these service contracts.

(6) 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.

(7) We have recorded long-term liabilities on our balance sheet reflecting amounts we expect to pay in future periods beyond one year. These liabilities primarily relate to reserves for joint venture audits, major maintenance accruals related to our MTBE facility, environmental liabilities and other amounts. Amounts shown in the table represent our best estimate as to the timing of payments.

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 million 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 for 2016.

EPCO has assigned to us 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 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. For additional information regarding the retained leases, please read Note 14 on page 87 in our Notes To Consolidated Financial Statements.

RECENT ACCOUNTING DEVELOPMENTS

SFAS No. 143, "*Accounting for Asset Retirement Obligations.*" We adopted this standard as of January 1, 2003. This statement establishes accounting standards for the recognition and measurement of an asset retirement obligation ("ARO") liability and the associated asset retirement cost. Our adoption of this standard had no material impact on our financial statements. For a discussion regarding our implementation of this new standard, please read Notes 1 and 6 of the Notes to Consolidated Financial Statements in this annual report.

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. 146, "*Accounting for Costs Associated with Exit and Disposal Activities.*" We adopted this standard as of January 1, 2003. This statement requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of an entity's commitment to an exit or disposal plan. Our adoption of this standard has had no material impact on our financial statements.

SFAS No. 148, "*Accounting for Stock-Based Compensation – Transition and Disclosure.*" We adopted this standard as of December 31, 2002. This statement provides alternative methods of transition from a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123, "*Accounting for Stock-Based Compensation*," in both annual and interim financial statements. We have provided the information required by this statement in Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Apart from this additional footnote disclosure, 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.*" We adopted SFAS No. 149 on a prospective basis as of July 1, 2003. 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, "*Accounting for Derivative Instruments and Hedging Activities*." 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. 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*." We adopted this standard on July 1, 2003. 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. Our adoption of this standard has had no material impact on our financial statements.

FIN 45, "*Guarantor's Accounting and Disclosure Requirement from Guarantees, Including Indirect Guarantees of Indebtedness of Others*." We implemented this 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 in Note 9 of the Notes to Consolidated Financial Statements in this annual report. Our implementation of this interpretation has had no material impact on our financial statements.

FIN 46, "*Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51*." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN46R) in 2003 has had no material effect on our financial statements.

OUR CRITICAL ACCOUNTING POLICIES

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates should the underlying assumptions prove to be incorrect. The following describes the estimation risk in each of these significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

Property, plant and equipment is recorded at cost and is depreciated using the straight-line method over the asset's estimated useful life. Our plants, pipelines and storage facilities have estimated useful lives of five to 35 years. Our miscellaneous transportation equipment have estimated useful lives of three to 10 years. Depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. Straight-line depreciation results in depreciation expense being incurred evenly over the life of the asset. The determination of an asset's estimated useful life must take a number of factors into consideration, including technological change, normal depreciation and actual physical usage. If any of these assumptions subsequently change, the estimated useful life of the asset could change and result in an increase or decrease in depreciation expense. At December 31, 2003 and 2002, the net book value of our property, plant and equipment was $3.0 billion and $2.8 billion, respectively. We recorded $101.0 million and $72.5 million in depreciation expense during 2003 and 2002, respectively. For additional information regarding our property, plant and equipment, please read Notes 1 and 6 of the Notes to Consolidated Financial Statements included in this annual report.

Impairment charges and underlying estimated fair values

If we determine that an asset's undepreciated cost may not be recoverable due to impairment of the asset, then we are required to take a charge against earnings. Long-lived assets with recorded values that are not expected to be recovered through future expected cash flows are written-down to their estimated fair values. An asset is 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 undiscounted cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated margins and volumes; estimated useful life of the asset or asset group; and salvage values. If we initially determine that an asset's carrying value is recoverable through such undiscounted estimated cash flows and later revise these assumptions and determine that the opposite is true, we would be required to ascertain the fair value of the facility, which might ultimately result in an impairment charge being recorded.

If the carrying value of an asset exceeds the sum of its undiscounted expected cash flows, an impairment loss equal to the amount that the carrying value exceeds the fair value of the asset is recognized. The quoted market price of an asset on an active exchange or similar venue is the best determinant of fair value. However, in many instances, quoted market prices in such markets are not available. In those instances, the estimate of fair value is based on the best information available, including prices for similar assets and the results of using other valuation techniques (including present value techniques).

Since most of our plant and other fixed and intangible assets are not traded in an active market, we generally rely on the use of present value techniques when determining the fair value of such assets for the purpose of impairment testing. These techniques incorporate our best available information and assumptions regarding future cash flows, alternative courses of action, probabilities of such courses of action occurring and discount rates. To the extent that any of these underlying assumptions prove incorrect, we may be required to take additional impairment charges in the future.

Due to a 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 BEF's long-lived assets exceeded their collective fair value, which resulted in a non-cash impairment charge of $67.5 million. Our share of this loss is $22.5 million and is recorded as a component of "Equity in income (loss) of unconsolidated affiliates" in our Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2003. Our historical equity (and in the future, consolidated) earnings from BEF are classified under the Octane Enhancement business segment. For additional information regarding this impairment charge, please read Note 7 of the Notes to Consolidated Financial Statements in this annual report.

Amortization methods and estimated useful lives of qualifying intangible assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The approach to the valuation of each intangible asset will vary depending upon the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

Our recorded intangible assets primarily include the estimated value assigned to certain contract-based assets representing the rights we own arising from contractual agreements. A contract-based intangible 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 (1) the expected use of the asset by the entity, (2) the expected useful life of related assets (i.e., fractionation facility, storage well, etc.), (3) any legal, regulatory or contractual provisions, including renewal or extension periods that would not cause substantial costs or modifications to existing agreements, (4) the effects of obsolescence, demand, competition, and other economic factors and (5) the level of maintenance required to obtain the expected future cash flows.

If the underlying assumption(s) governing the amortization of an intangible asset were later determined to have significantly changed (either favorably or unfavorably), then we may be required to adjust the amortization period of such asset to reflect any new estimate of its useful life. Such a change would increase or decrease the annual amortization charge associated with the asset at that time. During 2002, we did not find it necessary to adjust the estimated useful life or amortization period of any of our intangible assets.

Should any of the underlying assumptions indicate that the value of the intangible asset might be impaired, we may be required to reduce the carrying value and subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life (i.e., amortization period) of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2003 and 2002, the carrying value of our intangible asset portfolio was $268.9 million and $277.7 million, respectively. We did not recognize any impairment losses related to our intangible assets during

2003 or 2002. For additional information regarding our intangible assets, please read Notes 1 and 8 of the Notes to Consolidated Financial Statements.

Methods we employ to measure the fair value of goodwill

Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is primarily comprised of the $73.6 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002. Since our adoption of SFAS No. 142, "*Goodwill and Other Intangible Assets*," on January 1, 2002, our goodwill amounts are no longer amortized. Instead, goodwill is tested annually at a reporting unit level, and goodwill is tested more frequently if certain circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. If such indicators are present (i.e., loss of a significant customer, economic obsolescence of plant assets, etc.), then the fair value of the reporting unit, including its related goodwill, is calculated and compared to its combined book value. Currently, our goodwill is primarily recorded as part of the Fractionation operating segment (based on the assets to which the goodwill relates).

If the fair value of the reporting unit exceeds its book value, then 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.

At December 31, 2003 and 2002, the carrying value of our goodwill was $82.4 million and $81.5 million, respectively. For additional information regarding our goodwill, please read Notes 1 and 8 of the Notes to Consolidated Financial Statements.

Our investment in Dixie 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 of Dixie and GulfTerra includes amounts attributable to goodwill. Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is other than a temporary decline. For additional information regarding our excess cost amounts, please read Notes 1 and 7 of the Notes to Consolidated Financial Statements.

For Dixie, the amount attributable to goodwill at December 31, 2003 was $9.2 million. For GulfTerra GP, the amount attributable to goodwill at December 31, 2003 was estimated at $328.2 million. The goodwill amount for GulfTerra GP represents our preliminary allocation of the purchase price pending completion of a fair value analysis which is expected to be completed during the second half of 2004. 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 will be reduced from what it otherwise would be.

The table below shows the potential decrease in equity earnings from GulfTerra GP if certain amounts of the $328.2 million of excess cost preliminarily attributable to goodwill were ultimately assigned to fixed or intangible assets. For purposes of calculating this sensitivity, we have applied the straight-line method of cost allocation (i.e. depreciation or amortization) over an estimated useful life of 20-years to various fair values.

	Excess Cost attributed to tangible or intangible assets	**Estimated Annual Reduction in Equity Earnings**
20% of excess cost	$ 65,643	$ 3,282
40% of excess cost	131,286	6,564
60% of excess cost	196,928	9,846
80% of excess cost	262,571	13,129
100% of excess cost	328,214	16,411

Our revenue recognition policies

In general, we recognize revenue from our customers when all of the following criteria are met: (i) firm contracts are in place, (ii) delivery has occurred or services have been rendered, (iii) pricing is fixed and determinable and (iv) collectibility is reasonably assured. When contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), we determine if an allowance is necessary and record it accordingly. Historically, the consolidated revenues we recorded were not materially based on estimates. However, as SEC regulations require us to submit financial information on increasingly accelerated timeframes, our use of estimates will increase. We believe the assumptions underlying any revenue estimates that we might use will not prove to be materially different from actual amounts due to our development and implementation of a fully integrated volume management system that is inclusive of operational activities through financial accounting.

For additional information regarding our revenue recognition policies, please read Note 3 of the Notes to Consolidated Financial Statements included in this annual report.

Mark-to-market accounting for certain financial instruments

Our earnings are also affected by use of the mark-to-market method of accounting for certain financial instruments. We use short-term, highly liquid financial instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments and certain anticipated transactions, primarily within our Processing segment. The use of mark-to-market accounting for financial instruments may cause our non-cash earnings to fluctuate based upon changes in underlying indexes, primarily those related to commodity prices. Fair value for the financial instruments we employ is determined using price data from highly liquid markets such as the NYMEX commodity exchange.

During 2002, we recognized a loss of $51.3 million from our commodity hedging activities. Of this loss, $5.6 million was attributable to the change in fair value of the portfolio between December 31, 2001 and December 31, 2002. In March 2002, the effectiveness of our primary commodity hedging strategy deteriorated due to an unexpected rapid increase in natural gas prices; therefore, the loss in value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. We exited the strategy underlying this loss in 2002.

During 2003, we utilized a limited number of commodity financial instruments from which we recorded a loss of $0.6 million. The fair value of open positions at December 31, 2003 was a nominal receivable amount. For additional information regarding our commodity financial instruments, please read Note 18 of the Notes to Consolidated Financial Statements included in this annual report.

For additional information regarding our use of financial instruments to manage risk and the earnings sensitivity of these instruments to changes in underlying commodity prices, please read the Processing segment discussions under " – *Our results of operations*" beginning on page 20 and also read "*Quantitative and Qualitative Disclosures About Market Risk*" on page 47 of this annual report.

Additional information regarding our financial statements can be found in our Notes to Consolidated Financial Statements in this annual report.

RELATED PARTY TRANSACTIONS

Relationship with EPCO and its affiliates

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, the remaining executive and other officers of our General Partner are employees of EPCO, including O.S. Andras who is our Chief Executive Officer and a director of the General Partner. For a listing of our directors and executive officers, please refer to page 112 of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the common units and Class B special 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. In addition, EPCO and Dan Duncan LLC, together, own 100% of our General Partner, which in turn owns a 2% general partner interest in us. Also, trust affiliates of EPCO (the 1998 Trust and 2000 Trust) owned 4,478,236 of our common units at February 20, 2004. Collectively, EPCO, Dan L. Duncan, the 1998 Trust and the 2000 Trust owned 54.6% of our partnership interests at February 20, 2004.

The principal business activity of the General Partner is to act as our managing partner. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. We reimburse EPCO for the costs associated with employees who work on our behalf. We have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products. In addition, we buy from and sell NGL products to EPCO's Canadian affiliate. During 2003, our related party revenues from EPCO were $4.2 million and our related party expenses with EPCO were $177.6 million.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At February 20, 2004, Shell owned approximately 18.3% of our partnership interests.

Our largest customer is Shell. For the year ended December 31, 2003, Shell accounted for 5.5% 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. During 2003, our related party revenues from Shell were $293.1 million and our related party expenses with Shell were $607.3 million.

The most significant contract affecting our natural gas processing business is the Shell margin-band/keepwhole processing agreement, which grants us the right to process Shell's current and future production within state and federal waters of the Gulf of Mexico. The Shell processing agreement includes a life of lease dedication, which may extend the agreement well beyond its initial 20-year term ending in 2019.

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

- the acquisition of TNGL's natural gas processing and related businesses in 1999 for approximately $528.8 million (this purchase price includes both the $166 million in cash we paid to Shell and the value of the 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.

OTHER ITEMS

Uncertainties regarding our investment in facilities that produce MTBE

We have a 66.7% ownership interest in BEF, which owns a facility currently producing MTBE. At December 31, 2003, the value of our underlying equity in BEF was $49.2 million. 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. For additional information regarding the impact of environmental regulation on BEF, please read "*Business and Properties – Regulation and Environmental Matters – Impact of the Clean Air Act's oxygenated fuels programs on our BEF investment*" included under Items 1 and 2 of our 2003 Form 10-K filed with the Securities and Exchange Commission.

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 amount 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.

Conversion of EPCO Subordinated Units to Common Units

On May 1, 2003, 10,704,936 of EPCO's subordinated units converted to common units as a result of our satisfying certain financial tests. The remaining 21,409,872 subordinated units converted to common units on August 1, 2003. These conversions have no impact upon our earnings per unit or distributions since subordinated units are already included in both the basic and fully diluted earnings per unit calculations and are distribution bearing.

Conversion of Shell Special Units to Common Units

On August 1, 2003, the last 10,000,000 of Shell's non-distribution bearing special units converted to common units. The conversion impacted basic earnings per unit beginning in the third quarter of 2003. These units were already included in our fully diluted earnings per unit computations. Since common units are distribution bearing, our limited partner cash distributions to Shell increased beginning with the distribution we made in November 2003.

Facility and sensitive infrastructure security matters

Following the 2001 terrorist attacks in the United States, we instituted a review of security measures and practices and emergency response capabilities for all facilities and sensitive infrastructure. In connection with this activity, we have participated in security coordination efforts with law enforcement and public safety authorities, industry mutual-aid groups and regulatory agencies. As a result of these steps, we believe that our security measures, techniques and equipment have been enhanced as appropriate on a location-by-location basis. Further evaluation will be ongoing, with additional measures to be taken as specific governmental alerts, additional information about improving security and new facts come to our attention.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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. For additional information regarding our financial instruments, please read Note 18 of the Notes to Consolidated Financial Statements in this annual report.

Commodity price risk

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 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 established by our General Partner. 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. The General Partner 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, "*Accounting for Derivative Instruments and Hedging Activities*," 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, with the result being that changes in the fair value of these positions being 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.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis performed on this portfolio measures the potential income or loss (e.g., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the dates noted within the following table. In general, the quoted market prices used in the model are from those actively quoted on commodity exchanges (i.e., NYMEX) for instruments of similar duration. In those rare instances where prices are not actively quoted, we employ regression analysis techniques possessing strong correlation factors.

The sensitivity analysis model takes into account the following primary factors and assumptions:

- the current quoted market price of natural gas;
- the current quoted market price of NGLs;
- changes in the composition of commodities hedged (i.e., the mix between natural gas and related NGLs); fluctuations in the overall volume of commodities hedged (for both natural gas and related NGL hedges outstanding);
- market interest rates, which are used in determining the present value; and
- a liquid market for such financial instruments.

An increase in fair value of the commodity financial instruments (based upon the factors and assumptions noted above) approximates the income that would be recognized if all of the commodity financial instruments were settled at the dates noted within the table. Conversely, a decrease in fair value of the commodity financial instruments would result in the recording of a loss.

The sensitivity analysis model does not include the impact that the same hypothetical price movement would have on the hedged commodity positions to which they relate. Therefore, the impact on the fair value of the commodity financial instruments of a change in commodity prices would be offset by a corresponding gain or loss on the hedged commodity positions, assuming:

- the commodity financial instruments function effectively as hedges of the underlying risk;
- the commodity financial instruments are not closed out in advance of their expected term; and
- as applicable, anticipated underlying transactions settle as expected.

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

The following table shows the effect of hypothetical price movements on the fair value ("FV") of our commodity financial instrument portfolio and the related potential impact on our earnings ("IE") at the dates indicated (dollars in thousands):

Scenario	**Resulting classification**	**At 12/31/02**	**At 12/31/03**	**At 02/20/04**
FV assuming no change in quoted market prices	*Asset (Liability)*	$ (26)	$ 4	$ 2
FV assuming 10% increase in quoted market prices	*Asset (Liability)*	$ (26)	$ 4	$ 2
IE assuming 10% increase in quoted market prices	*Income (Loss)*	$ -	$ -	$ -
FV assuming 10% decrease in quoted market prices	*Asset (Liability)*	$ (26)	$ 4	$ 2
IE assuming 10% decrease in quoted market prices	*Income (Loss)*	$ -	$ -	$ -

During 2003, we recognized a loss of $0.6 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses in the Statements of Consolidated Operations. Of the loss recognized in 2003, $0.8 million is related to commodity hedging activities associated with natural gas purchases within the Pipeline segment offset by a $0.2 million gain from commodity hedging activities associated with the hedging of NGL production within the Processing segment.

During 2002, we recognized a loss of $51.3 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses in the Statements of Consolidated Operations. Of the loss recognized in 2002, $5.6 million was related to non-cash mark-to-market income recorded on open positions at December 31, 2001. Due to commodity hedging losses we incurred during the first quarter of 2002, we exited most of our positions. For additional information regarding our Processing segment's results for 2002, please read

"*Management's Discussion and Analysis of Financial Condition and Results of Operations – Our results of operations - Year ended December 31, 2003 compared to year ended December 31, 2002*" on page 19 of this annual report. At end of 2003 and 2002, we had a limited number of commodity financial instruments outstanding. The fair value of the portfolio at February 20, 2004 was a nominal asset amount and was again comprised of a limited number of positions.

Product purchase commitments. We have long and short-term purchase commitments for NGLs, petrochemicals and natural gas with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, please read "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Our Contractual Obligations*" on page 39 of this annual report.

Interest rate risk

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

Interest rate swaps. At December 31, 2002, we had one interest rate swap outstanding having a notional amount of $54 million that was terminated on March 1, 2003 at the election of the counterparty. Upon the termination, we received $1.6 million associated with the final settlement of this swap. The fair value of this swap at December 31, 2002 was $1.6 million. There was no earnings impact from the termination of this swap.

On January 8, 2004, we entered into three interest rate swaps under which we agreed to pay variable rates of interest to mitigate the changes in fair value of fixed rate debt as shown below:

Hedged Fixed-Rate Debt	Effective Date	Termination Date	Notional Amount
Senior Notes D, 7.50% fixed-rate	1/12/04	2/01/2011	$50 Million
Senior Notes C, 6.375% fixed-rate	1/12/04	2/01/2013	$100 Million
Senior Notes C, 6.375% fixed-rate	1/12/04	2/01/2013	$100 Million

We have designated these swaps as fair value hedges. The swap agreements have a combine notional amount of $250 million and match the maturity of the underlying debt being hedged. Under the swap agreements, we pay to the counterparty a floating LIBOR-based interest rate (plus an applicable margin) and receive back from the counterparty a fixed-rate payment equivalent to rate being charged us under the debt being hedged, all based on the notional amounts stated in each swap agreement.

The following table shows the effect of hypothetical price movements on the fair value ("FV") of our interest rate swap portfolio and potential change in the fair value of the debt. Income is not affected by changes in the fair value of the swap. However, the swap effectively converted the hedged portion of the fixed rate debt to a floating rate debt. Therefore, interest expense (and related cash flow) will increase or decrease with the change in the periodic "reset" rate associated with the respective interest rate swaps. The reset rate is the agreed upon index rate published for the first day of the six-month interest calculation period.

Scenario	Resulting Classification	At 2/20/04	Change in Fair Value of Debt
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ 978	$ -
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	$ (7,831)	$ (8,809)
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	$ 9,787	$ 8,809

Treasury Locks. During the fourth quarter of 2002, we entered into seven treasury lock transactions with original maturities of either January 31, 2003 or April 15, 2003. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific U.S. treasury security for an established period of time. The purpose of these transactions was to hedge the underlying treasury interest rate associated with our anticipated issuance of debt in early 2003 to partially refinance the Mid-America and Seminole acquisitions. Our treasury lock transactions were accounted for as cash flow hedges under SFAS No. 133. The notional amounts of these transactions totaled $550 million, with a total treasury lock rate of approximately 4%.

We elected to settle all of the treasury locks in early February 2003 in connection with our issuance of Senior Notes C and D. For additional information regarding Senior Notes C and D, please read "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Our liquidity and capital resource – Our debt obligations*" on page 34 of this annual report. The settlement of the treasury locks resulted in our receipt of $5.4 million of cash. The $5.4 million is being amortized into income as a reduction of interest expense over a 10-year period. The amortization period is based on the terms of the anticipated transaction as required by SFAS No. 133.

The fair value of these instruments at December 31, 2002 was a current liability of $3.8 million offset by a current asset of $0.2 million. The $3.6 million net liability was recorded as a component of comprehensive income on that date, with no impact to current earnings. With the settlement of the treasury locks, the $3.6 million net liability was reclassified out of accumulated other comprehensive income in Partners' Equity to offset the current asset and liabilities we recorded at December 31, 2002, with no impact to earnings. For additional information regarding our treasury lock transactions, please read Note 18 of the Notes to Consolidated Financial Statements on page 97 of this annual report.

Independent Auditors' Report

To the Board of Directors of Enterprise Products GP, LLC
(the General Partner of Enterprise Products Partners L.P.):

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related statements of consolidated operations and comprehensive income, consolidated cash flows and consolidated partners' equity for each of the three years in the period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits 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 financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2003 and 2002, and the results of its consolidated operations and its consolidated cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

The Company changed its method of accounting for goodwill in 2002 and for derivative financial instruments in 2001. These changes are discussed in Notes 8 and 1, respectively, to the consolidated financial statements.

Deloitte & Touche LLP

Houston, Texas
March 9, 2004

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

ASSETS	December 31, 2003	December 31, 2002
Current Assets		
Cash and cash equivalents (includes restricted cash of $13,851 at December 31, 2003 and $8,751 at December 31, 2002)	$ 44,317	$ 22,568
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $20,423 at December 31, 2003 and $21,196 at December 31, 2002	462,198	399,187
Accounts receivable – affiliates	347	228
Inventories	150,161	167,369
Prepaid and other current assets	30,160	48,216
Total current assets	687,183	637,568
Property, Plant and Equipment, Net	2,963,505	2,810,839
Investments in and Advances to Unconsolidated Affiliates	767,759	396,993
Intangible Assets, net of accumulated amortization of $40,371 at December 31, 2003 and $25,546 at December 31, 2002	268,893	277,661
Goodwill	82,427	81,547
Deferred Tax Asset	10,437	15,846
Long-Term Receivables	5,454	
Other Assets	17,156	9,818
Total	$ 4,802,814	$ 4,230,272

LIABILITIES AND PARTNERS' EQUITY	December 31, 2003	December 31, 2002
Current Liabilities		
Current maturities of debt	$ 240,000	$ 15,000
Accounts payable – trade	68,384	67,283
Accounts payable – affiliates	38,045	40,772
Accrued gas payables	622,982	489,562
Accrued expenses	24,695	35,760
Accrued interest	45,350	30,338
Other current liabilities	57,420	42,641
Total current liabilities	1,096,876	721,356
Long-Term Debt	1,899,548	2,231,463
Other Long-Term Liabilities	14,081	7,666
Minority Interest	86,356	68,883
Commitments and Contingencies		
Partners' Equity		
Common units (213,366,760 units outstanding at December 31, 2003 and 141,694,766 at December 31, 2002)	1,582,951	949,835
Subordinated units (32,114,804 units outstanding at December 31, 2002)		116,288
Class A special units (10,000,000 units outstanding at December 31, 2002)		143,926
Class B special units (4,413,549 units outstanding at December 31, 2003)	100,182	
Treasury units acquired by Trust, at cost (798,313 units outstanding at December 31, 2003 and 859,200 Units at December 31, 2002)	(16,519)	(17,808)
General Partner	34,349	12,223
Accumulated Other Comprehensive Income (Loss)	4,990	(3,560)
Total Partners' Equity	1,705,953	1,200,904
Total	$ 4,802,814	$ 4,230,272

See Notes to Consolidated Financial Statements

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

	For Year Ended December 31,		
	2003	2002	2001
REVENUES			
Third parties	$ 4,782,206	$ 3,102,066	$ 2,641,913
Related parties	564,225	482,717	512,456
Total revenues	5,346,431	3,584,783	3,154,369
COST AND EXPENSES			
Operating costs and expenses			
Third parties	4,246,229	2,687,260	2,053,148
Related parties	800,548	695,579	809,434
Total operating costs and expenses	5,046,777	3,382,839	2,862,582
Selling, general and administrative			
Third parties	10,463	18,686	10,347
Related parties	27,127	24,204	19,949
Total selling, general and administrative costs	37,590	42,890	30,296
Total costs and expenses	5,084,367	3,425,729	2,892,878
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	(13,960)	35,253	25,358
OPERATING INCOME	248,104	194,307	286,849
OTHER INCOME (EXPENSE)			
Interest expense	(140,806)	(101,580)	(52,456)
Dividend income from cost method unconsolidated affiliates	5,595	4,737	3,462
Interest income – other	772	2,313	7,029
Other, net	33	304	(234)
Total other income (expense)	(134,406)	(94,226)	(42,199)
INCOME BEFORE PROVISION FOR INCOME TAXES AND MINORITY INTEREST	113,698	100,081	244,650
PROVISION FOR INCOME TAXES	(5,293)	(1,634)	
INCOME BEFORE MINORITY INTEREST	108,405	98,447	244,650
MINORITY INTEREST	(3,859)	(2,947)	(2,472)
NET INCOME	104,546	95,500	242,178
Cumulative transition adjustment related to financial instruments recorded upon adoption of SFAS No. 133 (see Note 18)			(42,190)
Reclassification of cumulative transition adjustment to earnings			42,190
Cash flow hedges	5,354	(3,560)	
Reclassification of cash flow hedges	3,196		
COMPREHENSIVE INCOME	$ 113,096	$ 91,940	$ 242,178
ALLOCATION OF NET INCOME TO:			
Limited partners	$ 83,817	$ 84,837	$ 236,570
General partner	$ 20,729	$ 10,663	$ 5,608
BASIC EARNINGS PER UNIT			
Net income per common, subordinated and Class B unit	$ 0.42	$ 0.55	$ 1.70
DILUTED EARNINGS PER UNIT			
Net income per common, subordinated, Class A and Class B unit	$ 0.41	$0.48	$1.39

See Notes to Consolidated Financial Statements

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

	For Year Ended December 31,		
	2003	2002	2001
OPERATING ACTIVITIES			
Net income	$ 104,546	$ 95,500	$ 242,178
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:			
Depreciation and amortization in operating costs and expenses	115,643	86,028	48,775
Depreciation in selling, general and administrative costs	158	78	2,341
Amortization in interest expense	12,634	8,819	787
Provision for impairment of long-lived asset value	1,200		
Equity in loss (income) of unconsolidated affiliates	13,960	(35,253)	(25,358)
Distributions received from unconsolidated affiliates	31,882	57,662	45,054
Operating lease expense paid by EPCO	9,010	9,033	10,309
Other expenses paid by EPCO	436		
Minority interest	3,859	2,947	2,472
Gain on sale of assets	(16)	(1)	(390)
Deferred income tax expense	10,534	2,080	
Changes in fair market value of financial instruments	(29)	10,213	(5,697)
Net effect of changes in operating accounts	120,888	92,655	(37,143)
Operating activities cash flows	424,705	329,761	283,328
INVESTING ACTIVITIES			
Capital expenditures	(145,913)	(72,135)	(149,896)
Proceeds from sale of assets	212	165	568
Business combinations, net of cash received	(37,348)	(1,620,727)	(225,665)
Acquisition of intangible asset	(2,000)	(2,000)	
Investments in and advances to unconsolidated affiliates	(471,927)	(13,651)	(116,220)
Investing activities cash flows	(656,976)	(1,708,348)	(491,213)
FINANCING ACTIVITIES			
Borrowings under debt agreements	1,926,210	1,968,000	449,717
Repayments of debt	(2,033,000)	(637,000)	
Debt issuance costs	(8,833)	(19,329)	(3,125)
Distributions paid to partners	(309,918)	(214,869)	(164,308)
Distributions paid to minority interests	(8,113)	(3,324)	(1,687)
Contributions from minority interests	5,949	1,976	105
Proceeds from issuance of common units	573,684	180,666	
Proceeds from issuance of Class B special units	102,041		
Treasury Units purchased		(12,788)	(18,003)
Treasury Units reissued	646		22,600
Settlement of treasury lock financial instruments	5,354		
Increase in restricted cash	(5,100)	(2,999)	(5,752)
Financing activities cash flows	248,920	1,260,333	279,547
NET CHANGE IN CASH AND CASH EQUIVALENTS	16,649	(118,254)	71,662
CASH AND CASH EQUIVALENTS, JANUARY 1	13,817	132,071	60,409
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 30,466	$ 13,817	$ 132,071

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(Dollars in thousands, see Note 10 for unit history)

	Limited Partners							
	Common units	Subord. units	Class A Special units	Class B Special units	Treasury units	General Partner	Accum. OCI	Total
Balance, January 1, 2001	$ 514,896	$ 165,253	$ 251,132		$ (4,727)	$ 9,405		$ 935,959
Net income	163,795	72,775				5,608		242,178
Operating leases paid by EPCO	7,078	3,128				103		10,309
Cash distributions to partners	(109,969)	(49,510)				(4,829)		(164,308)
Class A special units issued to Shell under contingency agreement			117,066			1,183		118,249
Conversion of 10 million Class A special units to common units	72,554		(72,554)					
Treasury unit transactions:								
- Purchased					(18,003)			(18,003)
- Reissued and sold					16,508			16,508
- Gain on reissued treasury units	3,518	1,461	990			61		6,030
Cumulative transition adjustment recorded per SFAS No. 133							$ (42,190)	(42,190)
Reclassification of cumulative transition adjustment to earnings							42,190	42,190
Balance, December 31, 2001	$ 651,872	$ 193,107	$ 296,634		$ (6,222)	$ 11,531	$ -	$1,146,922
Net income	69,636	15,201				10,663		95,500
Operating leases paid by EPCO	6,872	2,071				90		9,033
Cash distributions to partners	(153,449)	(49,564)				(11,856)		(214,869)
Conversion of 19 million Class A special units to common units	152,708		(152,708)					
Conversion of 10.7 million subordinated units to common units	44,265	(44,265)						
Proceeds from issuance of common units (see Note 10)	178,859					1,807		180,666
Treasury unit transactions:								
- Purchased					(12,788)			(12,788)
- Reissued to satisfy unit options	(928)	(262)			1,202	(12)		
Change in fair value of financial instruments recorded as cash flow hedges							(3,560)	(3,560)
Balance, December 31, 2002	$ 949,835	$ 116,288	$ 143,926		$ (17,808)	$ 12,223	$ (3,560)	$1,200,904

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY – (Continued)
(Dollars in thousands, see Note 10 for unit history)

	Limited Partners							
	Common units	Subord. units	Class A Special units	Class B Special units	Treasury units	General Partner	Accum. OCI	Total
Balance, December 31, 2002	$ 949,835	$ 116,288	$ 143,926		$ (17,808)	$ 12,223	$ (3,560)	$1,200,904
Net income	73,075	10,566		$ 176		20,729		104,546
Operating leases paid by EPCO	8,154	751		8		97		9,010
Other expenses paid by EPCO	435			(2)		3		436
Cash distributions to partners	(254,111)	(30,482)				(22,573)		(307,166)
Cash distributions related to unit options (see Note 15)	(2,721)					(31)		(2,752)
Conversion of 10 million Class A special units to common units	143,926		(143,926)					
Conversion of 10.7 million subordinated units to common units	97,123	(97,123)						
Proceeds from issuance of common units (see Note 10)	567,945					5,739		573,684
Proceeds from issuance of Class B special units (see Note 10)				100,000		2,041		102,041
Restructuring of General Partner ownership in our Operating Partnership (see Note 10)	(73)					16,127		16,054
Treasury unit transactions:								
- Reissued to satisfy unit options					640			640
- Gain on reissued treasury units	6							6
- Retired	(643)				649	(6)		
Treasury lock financial instruments recorded as cash flow hedges:								
- Reclassification of change in fair value							3,560	3,560
- Cash gains on settlement							5,354	5,354
- Amortization of gain as component of interest expense							(364)	(364)
Balance, December 31, 2003	$1,582,951	$ -	$ -	$ 100,182	$ (16,519)	$ 34,349	$ 4,990	$1,705,953

See Notes to Consolidated Financial Statements

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ENTERPRISE PRODUCTS PARTNERS L.P. including its consolidated subsidiaries is a publicly traded Delaware limited partnership listed on the NYSE symbol “EPD”. Unless the context requires otherwise, references to “we,” “us,” “our” or “Enterprise” are intended to mean the consolidated business and operations of Enterprise Products Partners L.P.

We were formed in April 1998 to own and operate certain NGL-related businesses of EPCO. We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (i.e., the Operating Partnership). We are owned 98% by our limited partners and 2% by our General Partner. We and our General Partner are affiliates of EPCO.

The consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after elimination of all material intercompany accounts and transactions. The majority-owned subsidiaries are identified based upon the determination that Enterprise possesses a controlling financial interest through direct or indirect ownership of a majority voting interest in the subsidiary. Investments in which we own 20% to 50% and exercise significant influence over operating and financial policies are accounted for using the equity method. Investments in which we own less than 20% are accounted for using the cost method unless we exercise significant influence over operating and financial policies of the investee in which case the investment is accounted for using the equity method.

Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. 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. We had no such impairment charges during 2002 or 2001; however, BEF recorded a $67.5 million asset impairment charge during 2003. Our share of this charge was $22.5 million which was recorded as a reduction in the equity earnings from BEF. See Note 7 for additional information regarding this asset impairment charge.

Certain reclassifications have been made to the prior years’ financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported net income or earnings per unit.

In May 2002, we completed a two-for-one split of each class of our partnership units. All references to number of units or earnings per unit contained in this document reflect the unit split, unless otherwise indicated.

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.

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 FLOWS are computed using the indirect method. For cash flow purposes, we consider all highly liquid investments with an original maturity of less than three months at the date of purchase to be cash equivalents.

DOLLAR AMOUNTS (except per unit amounts) presented in the tabulations within the notes to our financial statements are stated in thousands of dollars, unless otherwise indicated.

EARNINGS PER UNIT is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Notes 10 and 13 for additional information on the capital structure and earnings per unit computation.

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. Environmental costs, accrued environmental liabilities and expenditures to mitigate or eliminate future environmental contamination for each of the years in the three-year period ended December 31, 2003 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated \$1.6 million, \$1.7 million and \$1.3 million for the years ended December 31, 2003, 2002 and 2001, respectively. 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 our equity investments in Promix, Dixie, Neptune, La Porte, Nemo and GulfTerra GP. 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 the excess cost related to these investments.

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.

EXIT AND DISPOSAL COSTS are those charges associated with an exit activity that does not involve an entity newly acquired in a business combination or with a disposal activity covered by SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets.*" Examples of these costs include (i) termination benefits provided to current employees that are involuntarily terminated under the terms of a benefit arrangement that, in substance, is not an ongoing benefit arrangement or an individual deferred compensation contract, (ii) costs to terminate a contract that is not a capital lease, and (iii) costs to consolidate facilities or relocate employees. In accordance with SFAS No. 146, "*Accounting for Costs Associated with Exit and Disposal Activities*," we recognize such costs when they are incurred rather than at the date of our commitment to an exit or disposal plan. We adopted SFAS No. 146 on January 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

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.

On January 1, 2001, we adopted SFAS No. 133 which required us to recognize the fair value of our commodity financial instrument portfolio on the balance sheet based upon then current market conditions. The fair market value of the then outstanding commodity financial instruments portfolio was a net payable of $42.2 million (the "cumulative transition adjustment") with an offsetting equal amount recorded in Other Comprehensive Income ("OCI"). The amount in OCI was fully reclassified to earnings during 2001. See Note 18 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. We have not recognized any impairment losses related to our goodwill for any of the periods presented.

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.

We did not recognize any such impairment losses during 2002 or 2001; however, we did record a $1.2 million asset impairment charge related to our Petal NGL fractionator during 2003. This non-cash amount is a component of operating costs and expenses as shown on our 2003 Statement of Consolidated Operations. The Petal NGL fractionation facility was decommissioned in December 2003 after management decided that this older facility did not fit into our long-range plans due to poor economics of continued operations at the site. We continue to own this facility, the carrying value of which has been adjusted to its fair value of approximately $0.1 million.

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 Enterprise. 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 except for BEF, which became a majority-owned consolidated subsidiary on September 30, 2003. Prior to January 1, 2004, 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. As a result, our consolidated statement of operations for the first quarter of 2004 will reflect the cumulative effect of change in accounting method associated with the removal of BEF's $7.0 million liability for accrued costs for planned future major maintenance activities.

PROVISION FOR INCOME TAXES is primarily applicable to certain federal and/or state tax obligations of our Mid-America and Seminole pipelines. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. See Note 12 for additional information regarding our provision of income taxes.

Our limited partnership structure is not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

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 NYMEX exchange. At December 31, 2003 and 2002, cash and cash equivalents includes $13.9 million and $8.8 million of restricted cash related to these requirements, respectively.

REVENUE is recognized using the following criteria: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. See Note 3 for additional information regarding our revenue recognition process.

When the contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), a determination of the necessity of an allowance is made and recorded accordingly. Our allowance for doubtful accounts amount 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. Our allowance for doubtful accounts was $20.4 million and $21.2 million at December 31, 2003 and 2002, respectively.

UNIT OPTION PLAN ACCOUNTING is based on the intrinsic-value method described in APB No. 25, "*Accounting for Stock Issued to Employees.*" Under this method, no compensation expense is recorded related to options granted when the exercise price is equal to or greater than the market price of the underlying equity on the date of grant. In accordance with SFAS No. 148, "*Accounting for Stock-Based Compensation – Transition and Disclosure,*" we disclose the pro forma effect on our earnings as if the fair-value method of SFAS No. 123, "Accounting for Stock-Based Compensation" had been used instead of the intrinsic-value of APB No. 25. The effects of applying SFAS No. 123 in the following pro forma disclosure may not be indicative of future amounts as additional awards in future years are anticipated. The following table shows the pro forma effects for the periods indicated.

	For Year Ended December 31,		
	2003	2002	2001
Net income:			
As reported	$ 104,546	$ 95,500	$ 242,178
Additional unit option-based compensation expense estimated using fair-value based method	(1,107)	(2,077)	(1,684)
Pro forma	$ 103,439	$ 93,423	$ 240,494
Basic earnings per unit:			
As reported	$ 0.42	$ 0.55	$ 1.70
Pro forma	0.41	0.53	1.68
Diluted earnings per unit:			
As reported	$ 0.41	$ 0.48	$ 1.39
Pro forma	0.40	0.47	1.38

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the assumptions shown in the following table.

	2003	2002	2001
Expected life of options	7 years	7 years	7 years
Risk-free interest rate	3.79%	3.10%	3.83%
Expected dividend yield	9.12%	5.65%	5.30%
Expected Unit price volatility	29%	25%	20%

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 and the reported amounts of revenues and expenses during the reporting period 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.

2. OTHER RECENTLY ISSUED ACCOUNTING STANDARDS AND GUIDANCE

Other than those discussed in our general accounting policies (see Note 1), 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.

- *FIN 45,* "*Guarantor's Accounting and Disclosure Requirement from Guarantees, Including Indirect Guarantees of Indebtedness of Others*." We implemented this 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 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.

3. REVENUE RECOGNITION

The following summarizes our consolidated revenue recognition policies by business activity:

Pipeline, storage and import/export businesses. We enter into pipeline, storage and product handling contracts. Under our NGL, petrochemical and certain natural gas pipeline throughput contracts, revenue is recognized when volumes have been physically delivered for the customer through the pipeline. Revenue from this type of throughput contract is typically based upon a fixed fee per gallon of liquids or MMBtus of natural gas transported, whichever the case may be, multiplied by the volume delivered. The throughput fee is generally contractual or as regulated by various governmental agencies, including the FERC. Additionally, we have product sales contracts associated with our natural gas pipeline business whereby revenue is recognized when we sell and deliver a volume of natural gas to a customer. These natural gas sales contracts are based upon market-related prices as determined by the individual agreements.

In our storage contracts, we collect a fee based on the number of days a customer has NGL or petrochemical volumes in storage multiplied by a storage rate for each product. Under these contracts, revenue is recognized ratably over the length of the storage contract based on the storage rates specified in each contract. Revenues from product handling contracts (applicable to our import and export operations) are recorded once the services have been performed with the applicable fees stated in the individual contracts. In our export operations and certain of our pipelines, we record revenues related to demand fees collected from exporters and shippers when they contract for use of our facilities and later fail to do so. The demand fees are contractual and vary by agreement. We recognize revenue from contractual demand fees after the exporter or shipper fails to utilize our facilities during the slated timeframe.

NGL fractionation, isomerization and propylene fractionation businesses. We enter into NGL fractionation, isomerization and propylene fractionation fee-based (or tolling) arrangements, NGL fractionation percent-of-liquids contracts and propylene fractionation sales contracts. Under our tolling arrangements, we recognize revenue upon completion of all contract services and obligations. These tolling arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the principal variable costs of fractionation and isomerization operations.

At certain of our NGL fractionation facilities, a percent-of-liquids arrangement is utilized. A percent-of-liquids processing contract allows us to retain a contractually determined percentage of NGL products fractionated for our customer in lieu of collecting a cash-tolling fee per gallon. Under a percent-of-liquids arrangement, fractionation revenue is recognized and recorded on a monthly basis for transfers of retained NGL products to the NGL working inventory maintained within our Processing segment where it is then held for sale. Transfer pricing for these retained NGLs is based upon monthly market posted prices for such products. This intersegment revenue and offsetting cost to the Processing segment is eliminated in our reporting of consolidated revenues and expenses.

In our propylene fractionation product sales contracts, we recognize revenue once the products have been delivered to the customer. Pricing for sales contracts is based upon market-related prices as determined by the individual agreements.

Natural gas processing and related NGL marketing business. In our natural gas processing activities, we enter into margin-band/keepwhole contracts, percent-of-liquids contracts and fee-based contracts. The most significant contract affecting our natural gas processing activities is the 20-year Shell agreement, which is a margin-band, or a modified keepwhole arrangement which grants us the right to process Shell's current and future production with the state and federal waters of the Gulf of Mexico off Texas, Louisiana, Mississippi, Alabama and Florida. Under margin-band/keepwhole arrangements, we retain all of the mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered out of our inventory and sold to customers on sales contracts within our NGL marketing activities. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract, inventory, sell and deliver is less than the total amount of NGLs extracted. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. If a cash fee for services is stipulated by the contract, we record revenue once the natural gas has been processed and sent back to the producer (i.e., delivery has taken place).

Our NGL marketing activities within this segment use product sales contracts to sell and deliver out of inventory the NGLs transferred to it as a result of our keepwhole and percent-of-liquids arrangements and those it purchases for cash in the open market. These NGL sales contracts may include forward product sales contracts from time-to-time. Revenues from NGL sales contracts are recognized and recorded upon the delivery of the NGL products specified in each individual contract. Pricing terms in these sales contracts are based upon market-related prices for such products and can include pricing differentials due to factors such as differing delivery locations.

Octane enhancement business. Our octane enhancement business consists of our interest in Belvieu Environmental Fuels ("BEF"), which owns and operates a facility that produces motor gasoline additives to enhance octane. This facility currently produces MTBE. BEF's operations primarily occur as a result of a contract with Sunoco, Inc. ("Sun") whereby Sun is obligated to purchase all of the facility's MTBE output at market-related prices through September 2004. BEF recognizes its revenue once the product has been delivered to Sun.

In September 2003, we acquired an additional 33.3% interest in BEF. As a result, BEF became a majority-owned consolidated subsidiary of ours on September 30, 2003. Previously, BEF was accounted for as an equity-method unconsolidated affiliate. For the periods prior to our consolidation of BEF, gross operating margin for this segment consisted of our equity earnings from BEF, which in turn were dependent upon BEF's general revenue recognition policy. There has been no change in BEF's revenue recognition policies since we began consolidating its financial results with those of our own.

Other businesses. As part of our Other segment activities, we perform NGL marketing services for a small number of customers for which we charge a commission. Commissions are based on either a percentage of the final sales price negotiated on behalf of the client or a fixed-fee per gallon based on the volume sold for the client. Revenues are recorded at the time the services are complete.

Consolidated revenues compared to segment revenues. Segment revenues include intersegment and intrasegment revenues, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions. See Note 20 for additional information regarding intersegment and intrasegment revenues and a reconciliation of total segment revenues to total consolidated revenues.

4. BUSINESS COMBINATIONS

During 2003, we acquired EPIK's remaining 50% ownership interest, the Port Neches Pipeline, an additional 33.33% interest in BEF, an additional 37.4% interest in Wilprise and the remaining capital stock of OTC. We also made minor adjustments to the allocation of the purchase price we paid to acquire indirect interests in Mid-America and Seminole pipelines. Due to the immaterial nature of each transaction or event, individually and in the aggregate, our discussion of each of these transactions is limited to the following:

Acquisition of remaining 50% interest in EPIK. In March 2003, we purchased the remaining 50% ownership interests in EPIK. EPIK owns an NGL export terminal located in southeast Texas on the Houston Ship Channel. As a result of this acquisition, EPIK became a consolidated wholly owned subsidiary of ours (previously, it had been an equity-method unconsolidated affiliate).

Acquisition of Port Neches Pipeline. In March 2003, we acquired entities owning the Port Neches Pipeline (formerly known as the Quest Pipeline). The 70-mile Port Neches Pipeline transports high-purity grade isobutane produced at our facilities in Mont Belvieu to customers in Port Neches, Texas.

Acquisition of 33.3% interest in BEF. At the end of September 2003, we acquired an additional 33.3% ownership interest in BEF, which owns a facility that currently produces MTBE (a motor gasoline additive that enhances octane and is used in reformulated 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.

Acquisition of 37.4% interest in Wilprise. In October 2003, we acquired an additional 37.4% in Wilprise, which is a 30-mile NGL pipeline that extends from the interconnect with the Tri-States pipeline near Kenner, Louisiana to Sorrento, Louisiana. Due to this acquisition, Wilprise became a majority-owned consolidated subsidiary of ours on October 1, 2003. Previously, Wilprise was accounted for as an equity-method unconsolidated affiliate.

Acquisition of remaining capital stock of OTC. In November 2003, we purchased the remaining 50% of OTC's outstanding capital stock. OTC owns an above ground polymer grade propylene storage and export facility located in Seabrook, Texas that is affiliated with our Mont Belvieu propylene fractionation operation. Due to this acquisition, OTC became a wholly owned consolidated subsidiary of ours. In August 2003, we became operator of the export facility. As a result of obtaining significant control over OTC through our role as operator and having an existing owner and customer relationship with the facility, we began consolidating OTC's financial statements with ours beginning August 1, 2003. Previously, OTC was accounted for as an equity-method unconsolidated affiliate.

Other purchase price adjustments. We made purchase price adjustments relating to our $1.2 billion acquisition of indirect interests in the Mid-America and Seminole pipelines. These adjustments total a net $4.9 million and primarily relate to liabilities existing at July 31, 2002, which was the closing date of the acquisitions.

The following table shows our allocation of the purchase price for 2003 acquisitions, effects of consolidating entities that were formerly accounted for under the equity-method, and adjustments to purchase price allocations from prior periods. The fair value estimates for the EPIK, Port Neches, BEF, Wilprise and OTC transactions were developed using recognized business valuation techniques.

	2003 Business Acquisitions	Purchase Price Adjustments	Total
Cash and cash equivalents	$ 19,800		$ 19,800
Accounts receivable	8,906	$ (172)	8,734
Inventories	10,727		10,727
Prepaid and other current assets	7,024	(1,525)	5,499
Property, plant and equipment, net	110,522	20,930	131,452
Investments in and advances to unconsolidated affiliates	(57,172)		(57,172)
Intangible assets	4,057		4,057
Goodwill	880		880
Other assets	3,332	(124)	3,208
Accounts payable	(5,094)		(5,094)
Accrued gas payables	(5,370)		(5,370)
Accrued expenses	(3,725)	(1,887)	(5,612)
Other current liabilities	(4,615)	(11,449)	(16,064)
Other liabilities	(5,001)	(1,062)	(6,063)
Minority interest	(32,002)	168	(31,834)
Total net assets recorded	$ 52,269	$ 4,879	$ 57,148
Investee cash balances recorded upon consolidation	(19,800)		(19,800)
Business combinations, net of cash received	$ 32,469	$ 4,879	$ 37,348

Proposed Merger with GulfTerra

On December 15, 2003, we and certain of our affiliates, El Paso, and GulfTerra and certain of its affiliates entered into a series of agreements under which one of our wholly-owned subsidiaries and GulfTerra would merge, with GulfTerra surviving the merger and becoming a wholly-owned subsidiary of ours. 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 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 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 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, we 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, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method and GulfTerra will be a consolidated subsidiary of our company. Step Two of the proposed merger includes the following transactions:

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

  - Our 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 Enterprise common units, resulting in the issuance of approximately 103 million Enterprise common units to GulfTerra unitholders.

- *Step Three*. Immediately after Step Two is completed, we expect 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 we will acquire from El Paso as the South Texas midstream assets.

Our preliminary estimate of the total consideration for Steps One, Two and Three we 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 us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in 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 the Company and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions 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 our Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2003.

5. INVENTORIES

Our inventories were as follows at the dates indicated:

	December 31,	
	2003	2002
Working inventory	$ 135,451	$ 131,769
Forward-sales inventory	14,710	35,600
Inventory	$ 150,161	$ 167,369

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 OPIS and 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, see Note 3), 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. These non-cash adjustments are charged to operating costs and expenses in the period they are recognized and generally affect our segment operating results in the following manner:

- NGL inventory write-downs are recorded as a cost of the Processing segment's NGL marketing activities;
- Natural gas inventory write downs are recorded as a cost of the Pipeline segment's Acadian Gas operations; and
- Petrochemical inventory write downs are recorded as a cost of the Fractionation segment's petrochemical marketing activities or as a cost of the Octane Enhancement segment's MTBE operations, as applicable.

For the years ended December 31, 2003, 2002 and 2001, we recognized LCM adjustments of approximately $16.9 million, $6.3 million and $40.7 million, respectively. 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 18 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 the dates indicated:

	Estimated Useful Life in Years	December 31, 2003	December 31, 2002
Plants and pipelines [1]	5-35 [4]	$ 3,214,463	$ 2,860,180
Underground and other storage facilities [2]	5-35 [5]	288,199	283,114
Transportation equipment [3]	3-10	5,676	5,118
Land		23,447	23,817
Construction in progress		74,431	49,586
Total		3,606,216	3,221,815
Less accumulated depreciation		642,711	410,976
Property, plant and equipment, net		$ 2,963,505	$ 2,810,839

(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).

Depreciation expense for the years ended December 31, 2003, 2002 and 2001 was $101.0 million, $72.5 million and $43.4 million, respectively.

Asset retirement obligations. SFAS No. 143 establishes accounting standards for the recognition and measurement of an 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 AROs, 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. 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, Neptune and 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 20.

The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated:

	Ownership Percentage	December 31, 2003	December 31, 2002
Accounted for on equity basis:			
Fractionation:			
BRF	32.3%	$ 27,892	$ 28,293
BRPC	30.0%	16,584	17,616
Promix	33.3%	38,903	41,643
La Porte	50.0%	5,422	5,737
OTC (1)	50.0%		2,178
Pipeline:			
EPIK (1)	50.0%		11,114
Wilprise (1)	37.4%		8,566
Tri-States (2)	50.0%	44,119	25,552
Belle Rose	41.7%	10,780	11,057
Dixie	19.9%	35,988	36,660
Starfish	50.0%	40,664	28,512
Neptune	25.7%	74,647	77,365
Nemo	33.9%	12,294	12,423
Evangeline	49.5%	2,519	2,383
GulfTerra GP (3)	50.0%	424,947	
Octane Enhancement:			
BEF (1)	33.3%		54,894
Accounted for on cost basis:			
Processing:			
VESCO	13.1%	33,000	33,000
Total		$ 767,759	$ 396,993

(1) We acquired additional ownership interests in these entities during 2003 resulting in our consolidation of each company's post-acquisition financial results with those of our own. See Note 4 for information regarding these acquisitions.
(2) In October 2003, we acquired an additional 16.7% ownership interest in Tri-States from Williams.
(3) 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.

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 but is subject to evaluation for impairment as described in Note 1 under "Excess Cost over Underlying Equity in Net Assets." 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	Unamortized balance at December 31, 2002	Amortization charged against equity earnings during 2003
Fractionation segment:						
Promix	20 years	$ 7,955		$ 6,256	$ 6,596	$ 340
La Porte	35 years	873		789	833	44
Pipelines segment:						
Dixie	35 years (1)	28,448	$ 9,246	34,084	34,901	817
Neptune	35 years	12,768		11,674	12,039	365
Nemo	35 years	727		676	697	21
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.

The table below shows the potential decrease in equity earnings from GulfTerra GP if certain amounts of the $328.2 million of excess cost preliminarily attributable to goodwill were ultimately assigned to fixed or intangible assets. For purposes of calculating this sensitivity, we have applied the straight-line method of cost allocation (i.e. depreciation or amortization) over an estimated useful life of 20-years to various fair values.

	Excess Cost attributed to tangible or intangible assets	Estimated Annual Reduction in Equity Earnings
20% of excess cost	$ 65,643	$ 3,282
40% of excess cost	131,286	6,564
60% of excess cost	196,928	9,846
80% of excess cost	262,571	13,129
100% of excess cost	328,214	16,411

The following table shows our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	Ownership Percentage	For Year Ended December 31, 2003	2002	2001
Fractionation:				
BRF	32.3%	$ 832	$ 2,427	$ 1,583
BRPC	30.0%	1,198	997	1,161
Promix	33.3%	2,106	3,936	4,201
La Porte	50.0%	(698)	(559)	
OTC [1]	50.0%	(77)	378	
Pipelines:				
EPIK [1]	50.0%	1,818	4,688	345
Wilprise [1]	37.4%	276	948	472
Tri-States [2]	33.3%	1,542	1,959	1,565
Belle Rose	41.7%	(55)	203	103
Dixie	19.9%	1,323	1,231	2,092
Starfish	50.0%	3,279	7,346	4,122
Ocean Breeze [3]	25.7%			32
Neptune	25.7%	1,014	2,111	4,081
Nemo	33.9%	1,268	1,077	75
Evangeline	49.5%	131	(58)	(145)
Gulf Terra [4]	50.0%	(53)		
Octane Enhancement:				
BEF [1,5]	33.3%	(27,864)	8,569	5,671
Total		$ (13,960)	$ 35,253	$ 25,358

(1) We acquired additional ownership interests in these entities during 2003 resulting in our consolidation of each company's post-acquisition financial results with those of our own. Equity earnings presented for 2003 for each company are for the period January 1, 2003 through acquisition date. See Note 4 for information regarding these acquisitions.
(2) In October 2003, we acquired an additional 16.7% ownership interest in Tri-States from Williams.
(3) Ocean Breeze was merged into Neptune in November 2001.
(4) On December 15, 2003, we acquired a 50% interest in the general partner of GulfTerra Energy Partners, L.P. from El Paso. Equity earnings presented for GulfTerra GP are for the period December 15, 2003 through December 31, 2003.
(5) Equity earnings from BEF for 2003 include a $22.5 million charge related to an asset impairment.

As used in the following condensed financial data, operating income represents earnings before non-operating income and expense items such as interest income and interest expense. The equity earnings we record from these investments represent our share of the net income of each.

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, we 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 ours. See Note 4 for additional information regarding our business combinations.

The combined balance sheet information for the last two years and results of operations data for the last three years of the Fractionation segment's equity method investments are summarized below.

	At December 31,	
	2003	**2002**
BALANCE SHEET DATA:		
Current assets	$ 16,049	$ 23,496
Property, plant and equipment, net	237,433	250,096
Total assets	$ 253,482	$ 273,592
Current and other liabilities	$ 4,216	$ 18,029
Combined equity	249,266	255,563
Total liabilities and combined equity	$ 253,482	$ 273,592

	For Year Ended December 31,		
	2003	**2002**	**2001**
INCOME STATEMENT DATA:			
Revenues	$ 72,217	$ 78,350	$ 76,480
Operating income	12,613	23,464	22,396
Net income	12,574	23,399	22,738

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, we 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. We purchased this interest from El Paso on December 15, 2003 for $425 million. Our purchase of this interest is Step One of our 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, we 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, we purchased an additional 37.4% interest in Wilprise Pipeline Company, LLC ("Wilprise"), at which time it became a 74.7% owned consolidated subsidiary of ours. See Note 4 for additional information regarding our business combinations.

The combined balance sheet information for the last two years and results of operations data for the last three years of the Pipelines segment's equity method investments are summarized below:

	At December 31,	
	2003	**2002**
BALANCE SHEET DATA:		
Current assets	$ 53,291	$ 76,930
Property, plant and equipment, net	486,696	510,483
Other assets	234,953	47,501
Total assets	$ 774,940	$ 634,914
Current liabilities	$ 53,477	$ 60,484
Other liabilities	55,619	56,230
Combined equity	665,844	518,200
Total liabilities and combined equity	$ 774,940	$ 634,914

	For Year Ended December 31,		
	2003	**2002**	**2001**
INCOME STATEMENT DATA:			
Revenues	$ 353,183	$ 303,567	$ 305,404
Operating income	90,723	65,855	54,459
Net income	75,098	56,736	41,015

Octane Enhancement segment:

In September 2003, we acquired an additional 33.3% interest in *Belvieu Environmental Fuels* ("BEF"), which owns a facility that currently produces 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 and is recorded as a component of "Equity in income (loss) of unconsolidated affiliates" in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2003.

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 flows 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 the present value of expected future cash flows being less than the new carrying value of the facility, additional impairment charges may result in the future. See Note 19 for additional information regarding risks associated with our investment in BEF.

The following table summarizes balance sheet and income statement data for BEF at and for the periods indicated prior to its consolidation with our financial results beginning on September 30, 2003:

	At December 31, 2002
BALANCE SHEET DATA: (1)	
Current assets	$ 37,237
Property, plant and equipment, net	129,019
Other assets	9,050
Total assets	$ 175,306
Current liabilities	$ 16,787
Other liabilities	4,017
Partners' equity	154,502
Total liabilities and partners' equity	$ 175,306

	For Nine Months Ended September 30, 2003 (2)	For Year Ended December 31, 2002	For Year Ended December 31, 2001
INCOME STATEMENT DATA:			
Revenues	$ 134,543	$ 229,358	$ 213,734
Non-cash impairment charge	(67,482)		
Operating income (loss)	(83,677)	25,461	15,984
Net income (loss)	(83,592)	25,707	17,014

(1) We began consolidating the financial position and results of operations of BEF beginning on September 30, 2003; therefore, only 2002 balance sheet data is shown.
(2) The 2003 period reflects the nine months that we accounted for BEF as an equity method investment.

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. As part of Other Income and Expense as shown in our Statements of Consolidated Operations and Comprehensive Income, we record dividend income from our investment in VESCO.

8. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

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

		At December 31, 2003		At December 31, 2002	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Shell natural gas processing agreement	$ 206,216	$ (34,063)	$ 172,153	$ (23,015)	$ 183,201
Storage II contracts	8,127	(464)	7,663	(232)	7,895
Splitter III contracts	53,000	(2,902)	50,098	(1,388)	51,612
Toca-Western natural gas processing contracts	11,187	(885)	10,302	(326)	10,861
Toca-Western NGL fractionation contracts	20,042	(1,587)	18,455	(585)	19,457
Venice contracts (1)	6,635	(136)	6,499		4,635
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	$ (25,546)	$ 277,661

(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 (see Note 4).
(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 (see Note 4).

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

- The Shell natural gas processing agreement that we 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 we acquired in connection with 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 we 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 (See Note 4). These fees are being amortized over the expected 20-year remaining useful life of the operations to which they relate.

The following table shows amortization expense associated with our intangible assets for the periods indicated:

	For Year Ended December 31,		
	2003	2002	2001
Shell natural gas processing agreement	$ 11,048	$ 11,054	$ 7,260
Mont Belvieu Storage II contracts	232	232	
Mont Belvieu Splitter III contracts	1,514	1,388	
Toca-Western natural gas processing contracts	559	326	
Toca-Western NGL fractionation contracts	1,002	585	
Venice contracts	136		
Port Neches pipeline contracts	310		
BEF UOP license fee (1)	24		
MBA acquisition goodwill (2)			449
Total	$ 14,825	$ 13,585	$ 7,709

(1) Amortization is for the three-month period that BEF was a consolidated subsidiary of ours.
(2) MBA acquisition goodwill was reclassified from Intangible Assets to Goodwill on January 1, 2002 per the transition provisions of SFAS No. 142, "*Goodwill and Other Intangible Assets*." In accordance with this accounting standard, we discontinued the amortization of goodwill on January 1, 2002.

For 2004, amortization expense attributable to these intangible assets is currently estimated at $15.3 million. Based on information currently available, we expect that amortization expense relating to existing intangible assets will also approximate $15.3 million for each of the years 2005 through 2008.

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

	Segment affiliation	At December 31, 2003	At December 31, 2002
Splitter III acquisition (1)	Fractionation	$ 73,690	$ 73,690
MBA acquisition (2)	Fractionation	7,857	7,857
Wilprise acquisition (3)	Pipelines	880	
		$ 82,427	$ 81,547

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

Since our adoption of SFAS No. 142 on January 1, 2002, our goodwill amounts are no longer amortized but are assessed annually for recoverability. Prior to our adoption of this standard, the only goodwill amortization we recorded was that associated with the MBA acquisition in July 1999. Due to the immaterial nature of such amortization expense ($0.4 million in 2001), the pro forma effect of not amortizing this goodwill in 2001 would have had a negligible effect on our net income and basic and diluted earnings per unit.

9. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

	December 31, 2003	December 31, 2002
Borrowings under:		
364-Day Term Loan, variable rate, repaid during 2003 (1)		$ 1,022,000
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	99,000
Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity (2)	115,000	225,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005 (3)	30,000	45,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed rate, due February 2013	350,000	
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	
Total principal amount	2,144,000	2,245,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,531	1,774
Less unamortized discounts on Senior Notes A, B and D	(5,983)	(311)
Subtotal long-term debt	2,139,548	2,246,463
Less current maturities of debt (4)	(240,000)	(15,000)
Long-term debt (4)	$ 1,899,548	$ 2,231,463
Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility (2)	$ 1,300	$ 2,400

(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, borrowings under this facility are not included in current maturities because we have the option and ability to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the agreement.

See Note 16 for our scheduled future maturities of long-term debt at December 31, 2003.

Parent-subsidiary guarantor relationships

We act as guarantor of all of our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own 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 our $425 million purchase from El Paso of a 50% membership interest in GulfTerra GP (see Note 7). The maturity date of this term loan is the earlier of September 2004 or the date our proposed merger with GulfTerra (see Note 4) is completed. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to our General Partner. We have 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 1/2% 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 ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires us 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 us, which would impair our ability to make distributions to our partners. As defined in the agreement, we 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 our General Partner. We have 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 1/2% 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 our General Partner. We have 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 1/2% 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 our General Partner. We have 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, we issued $350 million in principal amount of 6.375% fixed-rate senior notes due February 2013 ("Senior Notes C"), from which we 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, we exchanged 100% of the private placement Senior Notes C for publicly registered Senior Notes C.

In February 2003, we issued $500 million in principal amount of 6.875% fixed-rate senior notes due March 2033 ("Senior Notes D"), from which we 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, we 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 our October 2002 equity offering to partially repay this loan. We also used $252.8 million of the $258.1 million in proceeds from the January 2003 equity offering (see Note 10), $347.0 million of the $347.7 million in proceeds from our issuance of Senior Notes C and $421.4 million in proceeds from our 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. CAPITAL STRUCTURE

General

Our common units and Class B special units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Third Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement," together with any amendments thereto). Our outstanding common units are listed on the New York Stock Exchange under the symbol "EPD."

In December 2003, we issued Class B special units to an affiliate of EPCO. Class B special units have rights identical to our common units with respect to distributions and other matters. However, the Class B special units do not have voting rights and are not deemed to be outstanding for purposes of determining whether a quorum is present or whether the approval of the requisite number of holders of our units has been obtained. The Class B special units are convertible into common units on a one-for-one basis upon the receipt of approval of holders of not less than a majority of our common units (not including for this purpose the Class B special units) present and entitled to vote at a meeting of our common unitholders or by the holders of a majority of our common units (not including for this purpose the Class B special units) pursuant to written consents. We will request that our common unitholders approve the conversion of all of the Class B special units into common units at the special meeting that will be held to approve our merger with GulfTerra.

In December 2003, we restructured our General Partner's ownership interest in us and our Operating Partnership from a 1% ownership in us and a 1.0101% ownership in the Operating Partnership to a 2% ownership in us. As a result, our effective ownership in the Operating Partnership increased to 100% from 98.9899%. The purpose of the restructuring was to simplify and reduce the cost of compliance with the SEC rules relating to financial reporting requirements of subsidiaries. As a result of the restructuring, the Operating Partnership became exempt from the reporting requirements of Section 15(d) of the Securities Exchange Act of 1934 pursuant to Rule 12h-5 thereunder.

In February 2002, our General Partner approved a two-for-one split of each class of our partnership units. The unit split was accomplished by distributing one additional partnership unit for each partnership unit outstanding to holders of record on April 20, 2002. The units were distributed on May 15, 2002.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that the common units, Class B special units and General Partner will receive. See Note 11 for additional information regarding our distributions to partners.

The Partnership Agreement also contains provisions for the allocation of net earnings and losses to the unitholders and the General Partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. For financial accounting and tax purposes, the Class A special units (prior to their final conversion to common units in August 2003), were not allocated any portion of net income or loss; however, for tax purposes these units were allocated a certain amount of depreciation. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated 100% to the General Partner. See Note 11 for information regarding incentive cash distributions.

Equity offerings

The Partnership Agreement generally authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as shall be established by the General Partner in its sole discretion with the approval of unitholders. Since October 2002, we have completed a number of common unit offerings.

The following table reflects the number of common units issued and the net proceeds received from each offering:

		Net Proceeds from Common Unit Offerings			
Month of offering	**Number of common units issued**	**Contributed by Limited Partners**	**Contributed by General Partner**	**Contributed by General Partner in Minority Interest (1)**	**Total**
October 2002 (2)	9,800,000	$ 178,859	$ 1,807	$ 1,844	$ 182,510
January 2003 (3)	14,662,500	$ 252,942	$ 2,555	$ 2,608	$ 258,105
June 2003 (4)	11,960,000	255,891	2,584	2,639	261,114
August 2003 (5)	1,306,059	26,416	266	280	26,962
November 2003 (6)	1,577,744	32,696	334	334	33,364
Total 2003	29,506,303	$ 567,945	$ 5,739	$ 5,861	$ 579,545

(1) Prior to the restructuring of our General Partner's ownership interest in December 2003, the General Partner owned 1.0101% of the Operating Partnership. This ownership interest was accounted for as a component of minority interest in our historical Consolidated Balance Sheets.
(2) We used $178.8 million of the proceeds from this offering to repay a portion of the indebtedness outstanding under our 364-Day Term Loan. The remaining proceeds were used for working capital purposes.
(3) We used $252.8 million of the proceeds from this offering to repay a portion of the indebtedness outstanding under our 364-Day Term Loan. The remaining proceeds were used for working capital purposes.
(4) We used the net proceeds from this offering to reduce indebtedness outstanding under our revolving credit facilities.
(5) We used the net proceeds from this offering to reduce indebtedness outstanding under our revolving credit facilities and for general partnership purposes.
(6) We used the net proceeds from this offering for general partnership purposes.

In January 2003, we filed a $1.5 billion universal registration statement with the SEC covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). Our June 2003 equity offering utilized capacity available under this shelf. At December 31, 2003, we had approximately $1.2 billion of unused capacity under this shelf registration statement.

During 2003, we instituted a distribution reinvestment plan ("DRP") for our unitholders. The DRP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional common units. The registration statement we filed with the SEC relating to the DRP allows us to issue up to 5,000,000 common units under this program. As a result of any reinvestment proceeds we receive, our General Partner is required to make cash contributions to us in order to maintain its ownership interest. Initial reinvestments under this program occurred in August 2003.

In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO for $100 million in a private transaction. Our General Partner contributed approximately $2 million in connection with this offering in order to maintain its ownership interest. The purchase price for the Class B special units was approximately $22.66 per unit, representing a 5% discount from the $23.85 closing price of our common units on the NYSE on December 16, 2003. The 5% discount was consistent with the 5% discount available to all our unitholders under our distribution reinvestment plan. We used the net proceeds from this offering to repay $100 million of the debt we incurred to finance our December 2003 purchase of a 50% interest in GulfTerra GP (see Note 7) and the remainder for general partnership purposes.

Conversion of subordinated units to common units

During 2003, the remaining 32,114,804 subordinated units owned by EPCO converted to common units as a result of our satisfying certain financial tests. The subordinated units had no voting rights until their conversion to common units; however, they did receive allocations of income and loss. These conversions had no impact on our earnings per unit calculations or cash distributions since subordinated units were already included in both the basic and fully diluted earnings per unit calculations and were distribution bearing.

Conversion of Class A special units to common units

Class A special units were issued to Shell in conjunction with the 1999 TNGL acquisition and a related contingent unit agreement. We issued 29,000,000 Class A special units in August 1999 in connection with the acquisition. Subsequently, Shell met certain performance criteria in 2000 and 2001 that obligated us to issue an additional 12,000,000 Class A special units to Shell (6,000,000 in August 2000 and 6,000,000 in August 2001) under a contingent unit agreement. Of the cumulative 41,000,000 Class A special units issued, 2,000,000 converted to common units in August 2000, 10,000,000 converted in August 2001, 19,000,000 converted in August 2002 and 10,000,000 converted in August 2003. These conversions had a dilutive impact on basic earnings per unit since they increase the number of common units used in the computation. Class A special units were excluded from the computation of basic earnings per unit because they did not share in income or loss nor were they entitled to cash distributions until they were converted to common units. Under NYSE rules, the conversion of the Class A special units to common units required the approval of a majority of common unitholders. An affiliate of EPCO (which owns a majority of outstanding common units) voted in favor of such conversion, which provided the necessary votes for approval.

Treasury units

During 1999, our Operating Partnership established the EPOLP 1999 Grantor Trust (the "1999 Trust") to fund potential future obligations under the EPCO Agreement with respect to EPCO's long-term incentive plan (through the exercise of options granted to EPCO employees or directors of the General Partner). The 1999 Trust is included in our consolidated financial statements. Beginning in 2000, we and the 1999 Trust were authorized by the General Partner to repurchase up to 2,000,000 publicly held common units under a buy-back program. The repurchases will be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. Under the terms of the original buy-back program, common units repurchased by us were retired and common units repurchased by the 1999 Trust were classified as treasury units. In 2002, the buy-back program was modified to classify common units repurchased by us as treasury units.

The common units repurchased by us or the 1999 Trust are accounted for in a manner similar to treasury stock under the cost method of accounting. For the purpose of calculating both basic and diluted earnings per unit (see Note 13), treasury units are not considered to be outstanding.

The 1999 Trust purchased 792,800 common units during 2001 at a cost of $18 million and 100,000 common units during 2002 at a cost of $2.4 million. In 2001, the 1999 Trust sold 1,000,000 common units held in treasury to EPCO for $22.6 million. The sales price of these treasury units exceeded the purchase price of the treasury units by $6.0 million and was credited to partners' equity as a general contribution. We purchased 432,000 common units during 2002 at a cost of $10.3 million. In addition, 51,959 treasury units were reissued during 2002 at a weighted-average cost of $1.2 million to fulfill our obligations under EPCO employee unit option agreements. During 2003, we reissued 30,887 treasury units at a cost of $0.6 million primarily due to our obligations under EPCO employee unit option agreements and recorded a small gain on the transactions. We also retired 30,000 treasury units at a cost of $0.6 million during 2003.

Unit History table

The following table details the outstanding balance of each class of units for the periods and at the dates indicated:

	Limited Partners				
	Common Units	Subordinated Units	Class A Special Units	Class B Special Units	Treasury Units
Balance, January 1, 2001	92,514,630	42,819,740	33,000,000		534,400
Class A special units issued to Shell in connection with contingent unit agreement in August 2001			6,000,000		
Conversion of Class A special units to common units in August 2001	10,000,000		(10,000,000)		
Treasury unit transactions:					
Purchased	(792,800)				792,800
Reissued	1,000,000				(1,000,000)
Balance, December 31, 2001	102,721,830	42,819,740	29,000,000		327,200
Conversion of Class A special units to common units in August 2002	19,000,000		(19,000,000)		
Conversion of subordinated units to common units in August 2002	10,704,936	(10,704,936)			
Common units issued in October 2002	9,800,000				
Treasury unit purchases	(532,000)				532,000
Balance, December 31, 2002	141,694,766	32,114,804	10,000,000		859,200
Common units issued in January 2003	14,662,500				
Conversion of subordinated units to common units in May 2003	10,704,936	(10,704,936)			
Common units issued in June 2003	11,960,000				
Conversion of Class A special units to common units in August 2003	10,000,000		(10,000,000)		
Conversion of subordinated units to common units in August 2003	21,409,868	(21,409,868)			
Common units issued in August 2003 (1)	1,306,059				
Common units issued in November 2003 (1)	1,577,744				
Common units issued in December 2003	20,000				
Class B special units issued in December 2003				4,413,549	
Treasury unit transactions:					
Reissued	30,887				(30,887)
Retired					(30,000)
Balance, December 31, 2003	213,366,760	-	-	4,413,549	798,313

(1) Units issued primarily due to distribution reinvestment plan.

11. DISTRIBUTIONS

We intend, to the extent there is sufficient available cash from Operating Surplus (as defined by the Partnership Agreement) to distribute to each holder of common units at least a minimum quarterly distribution of $0.225 per common unit. The minimum quarterly distribution is not guaranteed and is subject to adjustment as set forth in the Partnership Agreement.

As an incentive, our General Partner's percentage interest in our quarterly cash distributions is increased after certain specified target levels are met. In December 2002, we amended our Partnership Agreement to eliminate the General Partner's right to receive 50% of our quarterly cash distributions with respect to that portion of the distribution based on declared rates that exceed $0.392 per common unit. Furthermore, our General Partner has capped its incentive distribution rights at 25% of our quarterly cash distributions with respect to that portion of the distribution based on declared rates that exceed $0.3085 per common unit. No consideration was paid to the General Partner to give up this right. As amended, our General Partner's quarterly incentive distribution thresholds are as follows (which include adjustments for the December 2003 restructuring of the General Partner's ownership interest in us and our Operating Partnership):

- 2% of quarterly cash distributions up to $0.253 per unit;
- 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and
- 25% of quarterly cash distributions that exceed $0.3085 per unit.

We made incentive distributions to the General Partner of $19.7 million, $9.8 million and $3.2 million during the years ended December 31, 2003, 2002 and 2001, respectively.

The following table summarizes quarterly cash distribution rates per unit during the periods indicated and the related record and distribution payment dates.

	Cash Distribution History		
	Distribution per Unit (1)	**Record Date**	**Payment Date**
2001			
1st Quarter	$ 0.2750	Apr. 30, 2001	May 10, 2001
2nd Quarter	$ 0.2938	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$ 0.3125	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$ 0.3125	Jan. 31, 2002	Feb. 11, 2002
2002			
1st Quarter	$ 0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	$ 0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter	$ 0.3450	Oct. 31, 2002	Nov. 12, 2002
4th Quarter	$ 0.3450	Jan. 31, 2003	Feb. 12, 2003
2003			
1st Quarter	$ 0.3625	Apr. 30, 2003	May 12, 2003
2nd Quarter	$ 0.3625	Jul. 31, 2003	Aug. 11, 2003
3rd Quarter	$ 0.3725	Oct. 31, 2003	Nov. 12, 2003
4th Quarter	$ 0.3725	Jan. 30, 2004	Feb. 11, 2004

(1) Distributions are paid on common units, subordinated units and Class B special units.

The quarterly cash distribution amounts shown in the table correspond to the cash flows for the quarters indicated. The actual cash distributions occur within 45 days after the end of such quarter.

12. PROVISION FOR INCOME TAXES FOR CERTAIN PIPELINE OPERATIONS

Our provision for income taxes is limited to certain income-based state franchise tax obligations of our Mid-America pipeline and our Seminole pipeline and federal tax obligations of our Seminole pipeline (both were acquired in 2002). One of our subsidiaries, which owns the Seminole pipeline, is a corporation and substantially our only consolidated entity subject to federal income taxes.

The following is a summary of the provision for income taxes for the above-mentioned pipeline operations for the periods indicated:

	For Year Ended December 31,	
	2003	2002
Current:		
Federal tax benefit		$ (391)
State tax expense (benefit)	$ 47	(55)
Total current	47	(446)
Deferred:		
Federal	4,556	1,812
State	690	268
Total deferred	5,246	2,080
Provision for income taxes	$ 5,293	$ 1,634

Our net deferred tax assets primarily relate to book versus tax basis differences in property, plant and equipment.

13. EARNINGS PER UNIT

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of common and subordinated units and Class B special units outstanding during a period. In general, diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of:

- the weighted-average number of common and subordinated units and Class A and Class B special units outstanding during a period; and
- the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net operating losses, the Class A special units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. Treasury units are not considered to be outstanding units; therefore, they are excluded from the computation of both basic and diluted earnings per unit.

The dilutive incremental option units are calculated in accordance with the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the beginning of each period are used to repurchase common units at average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

Beginning in August 2003, we reissued treasury units to satisfy the exercise of a small number of common unit options by employees of EPCO. The reissuance of these treasury units to satisfy EPCO's unit option liability has a dilutive effect on our earnings per unit. Prior to August 2003, EPCO had purchased practically all of the common units associated with its 1998 Plan in the open market. As a result, EPCO's unit option plan did not have any effect on our fully diluted earnings per unit in prior periods.

The amount of net income or loss allocated to limited partner interests is derived by subtracting our General Partner's share of our net income or loss and that attributable to the minority interest from income before minority interest.

The following table shows the allocation of net income or loss to our General Partner for the periods indicated:

	For Year Ended December 31,		
	2003	2002	2001
Net income	$ 104,546	$ 95,500	$ 242,178
Less priority earnings allocations to General Partner (1)	(19,699)	(9,806)	(3,218)
Net income available after priority earnings allocation	84,847	85,694	238,960
Multiplied by General Partner ownership interest (2)	1.2%	1.0%	1.0%
Standard earnings allocation to General Partner	$ 1,030	$ 857	$ 2,390
Priority earnings allocation to General Partner	$ 19,699	$ 9,806	$ 3,218
Standard earnings allocation to General Partner	1,030	857	2,390
General Partner interest	$ 20,729	$ 10,663	$ 5,608

(1) See Note 10 for information regarding priority earnings allocations to our General Partner.
(2) The General Partner's ownership interest in us increased from 1% to 2% in December 2003 as a result of restructuring its overall ownership interest in us and our Operating Partnership. The amount shown in the table represents a weighted-average of the General Partner's ownership interest in us during 2003. See Note 10 for information regarding this change in ownership structure.

The following table shows our calculation of net income available to limited partners, basic earnings per unit and diluted earnings per unit for the periods indicated:

	For Year Ended December 31,		
	2003	2002	2001
Income before minority interest	$ 108,405	$ 98,447	$ 244,650
General partner interest	(20,729)	(10,663)	(5,608)
Minority interest	(3,859)	(2,947)	(2,472)
Net income available to limited partners	$ 83,817	$ 84,837	$ 236,570
BASIC EARNINGS PER UNIT			
Numerator			
Net income available to limited partners	$ 83,817	$ 84,837	$ 236,570
Denominator			
Common units outstanding	183,779	119,820	96,633
Subordinated units outstanding	15,955	35,634	42,820
Class B special units outstanding	181		
Total	199,915	155,454	139,453
Basic earnings per unit			
Net income available to limited partners	$ 0.42	$ 0.55	$ 1.70
DILUTED EARNINGS PER UNIT			
Numerator			
Net income available to limited partners	$ 83,817	$ 84,837	$ 236,570
Denominator			
Common units outstanding	183,779	119,820	96,633
Subordinated units outstanding	15,955	35,634	42,820
Class A special units outstanding	5,808	21,036	31,334
Class B special units outstanding	181		
Incremental option units	644		
Total	206,367	176,490	170,787
Diluted Earnings per unit			
Net income available to limited partners	$ 0.41	$ 0.48	$ 1.39

14. RELATED PARTY TRANSACTIONS

Relationship with EPCO and its affiliates

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, the remaining executive and other officers of our General Partner are employees of EPCO, including O.S. Andras who is our President and Chief Executive Officer and a director of the General Partner. The principal business activity of the General Partner is to act as our managing partner.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the common units and Class B special 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. In addition, EPCO and Dan Duncan LLC, together, own 100% of our General Partner, which in turn owns a 2% general partner interest in us.

In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust) owned 4,478,236 of our common units at December 31, 2003. Collectively, EPCO, Dan L. Duncan, the 1998 Trust and the 2000 Trust owned 54.5% of our 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. Under the terms of the Administrative Services Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through our General Partner);
- 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 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 us 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 to us (the "retained leases"). EPCO remains liable for the cash lease payments associated with these assets.

Operating costs and expenses (as shown in our Statements of Consolidated Operations) treat the lease payments made by EPCO on our behalf as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the partnership. 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. In addition to retained lease expense, operating costs and expenses include compensation charges for EPCO's employees who operate our facilities.

Selling, general and administrative costs (as shown in our Statements of Consolidated Operations) include the costs we pay EPCO for administrative support. Through December 31, 2003, our payments to EPCO and related non-cash expenses for administrative support were based on the following:

- We reimbursed EPCO for our share of the costs of certain of its employees in administrative positions that were active at the time of our initial public offering in July 1998 (the "pre-expansion" administrative personnel). This includes costs associated with equity-based awards granted to certain individuals within this group. Our obligation for reimbursing these costs was covered by the EPCO Administrative Service Fee. During 2003, we paid $17.9 million in such fees to EPCO.

- To the extent that EPCO's actual cost of providing the pre-expansion administrative personnel exceeded the Administrative Service Fee charged us during a given year, we recorded a non-cash expense equal to the difference as a non-cash selling, general and administrative cost. The offset was recorded in Partners' Equity on the Consolidated Balance Sheets as a general contribution to the partnership. The actual amounts incurred by EPCO did not materially exceed the capped amounts for the years ended December 31, 2002 and 2001. For the year ended December 31, 2003, we recorded $0.4 million in non-cash expense related to this excess.

- We also reimburse EPCO for all costs it incurs related to administrative personnel it hires in response to our expansion and new business activities. This includes costs attributable to equity-based awards granted to members of this group.

Effective January 1, 2004, the Administrative Services Agreement was amended to eliminate a fixed Administrative Services Fee and to provide that we will reimburse EPCO for all costs related to administrative support regardless of whether the costs are related to pre-expansion or expansion 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. During 2003, 2002 and 2001, we paid EPCO $0.8 million, $0.8 million and $0.9 million for such services, respectively. Such payments were terminated effective 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.

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

	For Year Ended December 31,		
	2003	**2002**	**2001**
Revenues from consolidated operations			
EPCO and subsidiaries	$ 4,241	$ 3,630	$ 5,439
Operating costs and expenses			
EPCO and subsidiaries	149,626	103,210	62,919
Selling, general and administrative expenses			
Base fees payable under EPCO Agreement	17,940	16,638	15,125
Other EPCO compensation reimbursement	9,578	7,566	4,824
Other expenses paid by EPCO on our behalf	442	n/a	n/a

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 our partnership interests. Shell sold its 30.0% interest in our General Partner to an affiliate of EPCO in September 2003.

Our largest customer is Shell. For the years ended December 31, 2003, 2002 and 2001, they 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.

The most significant contract affecting our natural gas processing business is the Shell margin-band/keepwhole processing agreement, which grants us the right to process Shell's current and future production within state and federal waters of the Gulf of Mexico. The Shell processing agreement includes a life of lease dedication, which may extend the agreement well beyond its initial 20-year term ending in 2019. This contract was amended effective March 1, 2003. In general, the amended contract includes the following rights and obligations:

- the exclusive right, but not the obligation in all cases, to process substantially all of Shell's Gulf of Mexico natural gas production; plus
- the exclusive right, but not the obligation in all cases, to process all natural gas production from leases dedicated by Shell for the life of such leases; plus

- the right to all title, interest and ownership in the mixed NGL stream extracted by our gas processing plants from Shell's natural gas production from such leases; with
- the obligation to re-deliver to Shell the natural gas stream after any mixed NGLs are extracted.

As part of our natural gas processing obligations under this contract, we reimburse Shell for the energy value of (i) the NGLs we extract from the natural gas stream and (ii) the natural gas we remove from the stream and consume as fuel. This energy value is referred to as plant thermal reduction ("PTR") and is based on the energy content of the natural gas taken out of the stream (measured in Btus). The amended contract contains a mechanism (termed "Consideration Adjustment Outside of Normal Operations" or "CAONO") to adjust the value of the PTR we reimburse to Shell. The CAONO, in effect, protects us from processing Shell's natural gas at an economic loss when the value of the NGLs we extract is less than the sum of the cost of the PTR reimbursement, operating costs of the gas processing facility and other costs such as NGL fractionation and pipeline fees.

In general, the CAONO adjustment requires the comparison of our average net gas processing margin to an upper and lower limit (all as defined within the agreement). If our average net processing margin is below the lower limit, the PTR reimbursement payable to Shell is decreased by the product of the absolute value of the difference between our average net processing margin and the specified lower limit multiplied by the volume of NGLs extracted. To the extent our average net processing margin is higher than the upper limit, the PTR reimbursement payable to Shell is increased by the product of the difference between the average net gas processing margin and the specified upper limit multiplied by the volume of NGLs extracted. The underlying purpose of the CAONO mechanism is to provide Shell with relative assurance that its gas will continue to be processed during periods when natural gas prices are high relative to NGL prices (times when we would normally choose not to process a producer's natural gas stream) while continuing to protect us from processing Shell's gas at an economic loss.

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

	For Year Ended December 31,		
	2003	**2002**	**2001**
Revenues from consolidated operations			
Shell	$ 293,109	$ 282,820	$ 333,333
Operating costs and expenses			
Shell	607,277	531,712	705,440

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

- the acquisition of TNGL's natural gas processing and related businesses in 1999 for approximately $528.8 million (this purchase price includes both the $166 million in cash we paid to Shell and the value of the 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.

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

	For Year Ended December 31,		
	2003	2002	2001
Revenues from consolidated operations			
Evangeline	$ 212,662	$ 131,635	$ 117,283
BEF (1)	32,765	50,494	45,778
Promix	19,575	12,697	8,952
EPIK (2)	58	259	297
Other unconsolidated affiliates	1,834	1,182	1,374
Operating costs and expenses			
Dixie	11,296	12,184	12,695
BEF (1)	6,646	9,794	8,073
Promix	17,465	18,408	12,676
EPIK (2)	6,607	19,788	7,438
Other unconsolidated affiliates	1,738	483	193

(1) Amounts shown in the table reflect the period of time that we accounted for our investment in BEF using the equity-method. BEF became a consolidated subsidiary of ours on September 30, 2003. For additional information regarding our prior equity investment in BEF, please read Note 7.
(2) Amounts shown in the table reflect the period of time that we accounted for our investment in EPIK using the equity-method. EPIK became a consolidated subsidiary of ours on March 1, 2003. For additional information regarding our prior equity investment in EPIK, please read Note 7.

As part of Other Income and Expense as shown in our Statements of Consolidated Operations and Comprehensive Income, we record dividend income from our investment in VESCO.

15. UNIT OPTION PLAN ACCOUNTING

During 1998, EPCO adopted its 1998 Long-Term Incentive Plan (the "1998 Plan"). Under this program, non-qualified incentive options to purchase a fixed number of our common units may be granted to EPCO's key employees who perform management, administrative or operational functions for us. The exercise price per unit, vesting and expiration terms, and rights to receive distributions on units granted are determined by EPCO for each grant agreement. EPCO purchases common units to fund its obligations under the 1998 Plan at fair value either in the open market or from us (in the form of newly-issued common units or reissued treasury units).

We account for our share of the costs of these awards using the intrinsic value-based method in accordance with APB No. 25, "*Accounting for Stock Issued to Employees*." The exercise price of each option granted is equivalent to or greater than the market price of the unit at the date of grant. Accordingly, no compensation expense related to unit option grants has been recognized in our Statements of Consolidated Operations and Comprehensive Income. Any special distributions (as described in the following information) that we make to reimburse EPCO for its costs related to these awards are a component of "Cash distributions to partners" as shown in our Statements of Consolidated Partners' Equity.

Through December 31, 2003, our responsibility for reimbursing EPCO for the cash outlay it incurred when these options were exercised was as follows:

- We paid EPCO for the costs attributable to unit option awards granted to operations personnel it employs on our behalf. Our payment to EPCO is in the form of a special distribution.
- We paid EPCO for the costs attributable to unit option awards granted to administrative and management personnel it hired in response to our expansion and business activities. Our payment to EPCO is in the form of a special distribution.
- We paid EPCO for our share of the costs attributable to unit option awards granted to certain of its employees in administrative and management positions that were active at the time of our initial public offering in July 1998 under one of two methods.

    1. If EPCO purchased common units in open market to fund its obligation to any employee of this group, the cost was reimbursed by us through the Administrative Service Fees we paid EPCO (see Note 14). EPCO was responsible for the actual cost of such award when the option was exercised. To the extent that EPCO's total administrative expense incurred on our behalf (including the expense associated with equity-based awards satisfied through open market purchases) exceeded the annual Administrative Service Fee we paid to EPCO, such excess costs resulted in a non-cash charge to our earnings as a related-party expense and a corresponding increase in Partners' Equity recorded as a general contribution.

    2. If EPCO requested us to provide units to satisfy its obligations to these employees, we reimbursed EPCO in the form of a special distribution.

Effective January 1, 2004, the Administrative Services Agreement was amended to provide that we will reimburse EPCO for all costs (including those related to unit options) related to administrative support personnel regardless of whether the costs are related to pre-expansion or expansion personnel who work on our behalf. Our obligation regarding operations-related personnel remains the same. Under the amended agreement, our payment to EPCO for both administrative and operations personnel who exercise unit options will be in the form of a special distribution regardless of how the option liability is satisfied (i.e., through open market purchases or units acquired from EPCO affiliates or us). During 2003, we made $2.7 million of special cash distributions to EPCO to meet our obligations under EPCO's 1998 Plan.

Summary of 1998 Plan Activity

EPCO's 1998 Plan is used to issue unit option awards to the three categories of employees discussed previously in this Note 15. The information in the following table shows unit option activity for EPCO personnel who work on our behalf.

	Number of Units	Weighted-average strike price
Outstanding at January 1, 2001	1,931,758	$ 6.66
Granted	1,050,000	16.41
Exercised	(760,118)	4.94
Forfeited	(20,000)	9.00
Outstanding at December 31, 2001	2,201,640	11.88
Granted	379,000	23.42
Exercised	(270,562)	4.98
Outstanding at December 31, 2002	2,310,078	14.57
Granted	35,000	22.26
Exercised	(372,078)	7.10
Forfeited	(35,000)	18.86
Outstanding at December 31, 2003	1,938,000	$ 16.07
Options exercisable at:		
December 31, 2001	221,640	$ 1.65
December 31, 2002	711,078	$ 7.83
December 31, 2003	509,000	$ 9.68

				Options Exercisable at December 31, 2003	
Range of Strike Prices	Options outstanding at December 31, 2003	Weighted-Average Remaining Contractual Life (in Years)	Weighted Average Strike Price	Number Exercisable at December 31, 2003	Weighted Average Strike Price
\$7.75 - \$9.00	339,000	5.75	$ 8.63	339,000	$ 8.63
\$11.63 - \$12.56	210,000	6.83	11.91	170,000	11.76
\$15.93 - \$17.63	925,000	7.10	16.12		
\$21.15 - \$24.73	464,000	8.26	23.30		
	1,938,000			509,000	

The weighted-average fair value of options granted during 2003, 2002 and 2001 was \$2.17, \$3.12 and \$1.97 per option, respectively.

16. 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 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 (see Note 14). 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. See Note 15 for additional information regarding our accounting for unit options.

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 following table 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 following table 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 following table 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 following table 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 following table 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 million for 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 for 2016.

EPCO has assigned to us 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.

Third-party lease and rental expense included in operating income for the years ended December 31, 2003, 2002 and 2001 was approximately $17.8 million, $16.4 million and $13.0 million, respectively.

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.

17. SUPPLEMENTAL CASH FLOWS DISCLOSURE

The net effect of changes in operating assets and liabilities is as follows:

	For Year Ended December 31,		
	2003	2002	2001
(Increase) decrease in:			
Accounts and notes receivable	$ (54,388)	$ (127,365)	$ 231,532
Inventories	49,932	(84,254)	11,048
Prepaid and other current assets	11,073	15,340	(26,427)
Other assets	(226)	(3,322)	162
Increase (decrease) in:			
Accounts payable	(6,720)	23,901	(82,075)
Accrued gas payable	128,050	262,527	(178,102)
Accrued expenses	(16,677)	7,884	(1,576)
Accrued interest	15,012	5,369	14,234
Other current liabilities	(4,196)	(6,921)	3,073
Other liabilities	(972)	(504)	(9,012)
Net effect of changes in operating accounts	$ 120,888	$ 92,655	$ (37,143)
Cash payments for interest, net of $1,595, $1,083 and $2,946 capitalized in 2003, 2002 and 2001, respectively	$ 112,712	$ 82,535	$ 37,536
Cash payments for federal and state income taxes	$ 453	n/a	n/a

During 2003, we completed several business acquisitions, made adjustments to the 2002 purchase price allocation of the Mid-America and Seminole acquisitions; and consolidated entities that had been previously accounted for using the equity-method (see Note 4). During 2002, we completed $1.8 billion in business acquisitions, the most significant of which were the acquisition of interests in the Mid-America and Seminole pipelines from Williams and propylene fractionation and NGL and petrochemical storage assets from Diamond-Koch. During 2001, we acquired Acadian Gas from Shell. These transactions and events over the last three years affected various balance sheet categories summarized as follows:

	For Year Ended December 31,		
	2003	2002	2001
Current assets	$ 24,960	$ 53,287	$ 83,123
Property, plant and equipment	131,452	1,507,243	225,169
Investments in unconsolidated affiliates	(57,172)	7,550	2,723
Intangible assets	4,057	92,356	
Goodwill	880	73,691	
Deferred tax asset		17,307	
Other assets	3,208	2,699	
Current liabilities	(32,140)	(17,747)	(83,890)
Long-term debt		(60,000)	
Other liabilities	(6,063)	(90)	(1,460)
Minority interest	(31,834)	(55,569)	
Total	$ 37,348	$ 1,620,727	$ 225,665

We record various financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. The amount for 2003 was negligible. During 2002, we recognized a net $10.2 million in non-cash mark-to-market decreases in the fair value of these instruments, primarily in our commodity financial instruments portfolio. During 2001, we recognized a net $5.6 million in non-cash mark-to-market increases in the fair value of our financial instruments portfolio.

During 2003 and 2002, we acquired 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. Of the $6.6 million value of this intangible asset, $2.6 million was reclassified from construction-in-progress during 2002 and $4.0 million represents the actual cash payments made to the third-party during 2003 and 2002. The prior expenditures recorded as construction-in-progress were reclassified due to the direct linkage between these expenditures and the successful negotiation of the Venice contracts.

Cash and cash equivalents (as shown on our Statements of Consolidated Cash Flows) excludes restricted cash amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for our physical purchase transactions made on the NYMEX exchange. The restricted cash balance at December 31, 2003 and 2002 was $13.9 million and $8.8 million, respectively.

18. 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 established by the General Partner. 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. The General Partner 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.

During 2003, we recognized a loss of $0.6 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses in the Statements of Consolidated Operations. Of the loss recognized in 2003, $0.8 million loss is related to commodity hedging activities associated with natural gas purchases within the Pipeline segment offset by a $0.2 million gain from commodity hedging activities associated with the hedging of NGL production within the Processing segment.

During 2002, we recognized a loss of $51.3 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses in the Statements of Consolidated Operations. Of the loss recognized in 2002, $5.6 million is related to non-cash mark-to-market income recorded on open positions at December 31, 2001. During 2001, we posted income of $101.3 million from our commodity hedging activities, which served to reduce operating costs and expenses.

Beginning in late 2000 and extending through March 2002, a large number of our commodity hedging transactions were based on the historical relationship between natural gas prices and NGL prices. This type of hedging strategy utilized the forward sale of natural gas at a fixed-price with the expected margin on the settlement of the position offsetting or mitigating changes in the anticipated margins on NGL marketing activities and the value of our equity NGL production. Throughout 2001, this strategy proved very successful to us (as the price of natural gas declined relative to our fixed positions) and was responsible for most of the $101.3 million in commodity hedging income we recorded during 2001.

In late March 2002, the effectiveness of this strategy deteriorated due to an unexpected rapid increase in natural gas prices whereby the loss in the value of our fixed-price natural gas financial instruments was not offset by increased gas processing margins. Due to the inherent uncertainty that was controlling natural gas prices at the time, we decided that it was prudent to exit this strategy, and we did so by late April 2002. The failure of this strategy is the primary reason for the $51.3 million in commodity hedging losses we recorded during 2002.

We had a limited number of commodity financial instruments open at December 31, 2003 and 2002. The fair value of these open positions at December 31, 2003 and 2002 was an asset of $4 thousand and a liability of $26 thousand, respectively (both amounts based on market prices on these dates).

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. The

General Partner 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.

At December 31, 2002, we had one interest rate swap outstanding having a notional amount of $54 million that extends through March 2010. Under this agreement, we exchanged a fixed-interest rate of 8.7% for a variable-interest rate that ranged from 1.8% to 4.5% during 2002 (the variable-interest rate we paid under this swap fluctuated over time depending on market conditions). The counterparty exercised its right to early termination of this swap in March 2003; therefore, only a minimal amount of income was recognized in 2003 from this financial instrument. We recognized income from our interest rate swaps of $0.9 million during 2002 compared to $13.2 million during 2001. This income is recorded as a reduction of interest expense in our Statements of Consolidated Operations. 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. The fair value of these instruments at December 31, 2002 was a current liability of $3.8 million offset by a current asset of $0.2 million. The net $3.6 million non-cash mark-to-market liability was recorded as a component of comprehensive income on that date, with no impact to current earnings.

We elected to settle all of the treasury locks by early February 2003 in connection with our 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.

Of the $5.4 million recorded in other comprehensive income during the first quarter of 2003, $4.0 million is attributable to our issuance of Senior Notes C and will be amortized to earnings as a reduction in interest expense over the 10-year term of this debt. The remaining $1.4 million is attributable to our issuance of Senior Notes D and will be amortized to earnings as a reduction in interest expense over the 10-year term of the anticipated transaction as required by SFAS No. 133. The amount reclassified from accumulated other comprehensive income to earnings during 2003 was $0.4 million. We expect to reclassify $0.4 million from other comprehensive income as a reduction to interest expense during 2004. With the settlement of the treasury locks, the $3.6 million non-cash mark-to-market liability recorded at December 31, 2002 was reclassified out of accumulated other comprehensive income in Partners' Equity to offset the current asset and liabilities we recorded at December 31, 2002 with no impact to earnings.

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 and 2002:

	At December 31, 2003		At December 31, 2002	
Financial instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 44,317	$ 44,317	$ 22,568	$ 22,568
Accounts receivable	462,545	462,545	399,415	399,415
Commodity financial instruments (1)	358	358	513	513
Interest rate hedging financial instruments (2)			203	203
Financial liabilities:				
Accounts payable and accrued expenses	799,456	799,456	663,715	663,715
Fixed-rate debt (principal amount)	1,734,000	1,849,327	899,000	1,027,749
Variable-rate debt	410,000	410,000	1,346,000	1,346,000
Commodity financial instruments (1)	355	355	539	539
Interest rate hedging financial instruments (2)			3,766	3,766

(1) Represent commodity financial instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(2) Represent interest rate hedging financial instrument transactions that had not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

19. 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 amount 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.

20. 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 the CEO of the General Partner. 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.

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

We define total segment gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions.

Segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. These transactions include, but are not limited to the following types:

- NGL fractionation revenues from separating our mixed NGL inventories into distinct NGL products using our fractionation plants as directed by our NGL marketing activities (an intersegment revenue of the Fractionation segment offset by an intersegment expense of the Processing segment);
- NGL pipeline revenues from transporting mixed NGL volumes using our pipelines to our NGL fractionation plants as directed by our NGL marketing activities (an intersegment revenue of the Pipelines segment offset by an intersegment expense of the Processing segment);
- Transfer sales of mixed NGLs retained under keepwhole or percent-of-liquids arrangements between our natural gas processing plants to our NGL marketing activities (an intrasegment revenue of the Processing segment offset by an intrasegment expense of the Processing segment); and
- Transfer sales of mixed NGLs retained under percent-of-liquids arrangements by our Norco NGL fractionator to our NGL marketing activities (an intersegment revenue of the Fractionation segment offset by an intrasegment expense of the Processing segment).

Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions. See Note 3 for information regarding our revenue recognition policies.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be 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. For example, we use the Promix NGL fractionator to process a portion of the mixed NGLs extracted by our gas plants. Another example would be our use of the Dixie pipeline to transport propane sold to customers through our NGL marketing activities. See Note 14 for additional information regarding our related party relationships with unconsolidated affiliates.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States. Most of our plant-based operations are located primarily along the western Gulf Coast in Texas, Louisiana and Mississippi. Our pipelines and related operations are in a number of regions of the United States including the Gulf of Mexico offshore Louisiana (certain natural gas pipelines); the south and southeastern United States (primarily in the Texas, Louisiana and Mississippi regions); and certain regions of the central and western United States. The Mid-America pipeline system extends from the Hobbs hub located on the Texas-New Mexico border to Wyoming along one route and to Minnesota, Wisconsin and Illinois along other routes. Our marketing activities are headquartered in Houston, Texas at our main office and service customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are 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.

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

	For Year Ended December 31,		
	2003	2002	2001
Revenues [(1)]	$ 5,346,431	$ 3,584,783	$ 3,154,369
Less operating costs and expenses [(1)]	(5,046,777)	(3,382,839)	(2,862,582)
Add equity in income (loss) of unconsolidated affiliates [(2)]	(13,960)	35,253	25,358
Subtotal	285,694	237,197	317,145
Add: Depreciation and amortization in operating costs and expenses [(3)]	115,643	86,028	48,775
Retained lease expense, net in operating expenses allocable to us [(4)]	9,010	9,033	10,309
Retained lease expense, net in operating expenses allocable to our General Partner's minority interest in us [(5)]	84	92	105
Loss (gain) on sale of assets in operating costs and expenses [(1)]	(16)	(1)	(390)
Total segment gross operating margin	$ 410,415	$ 332,349	$ 375,944

(1) These amounts are comprised of both third party and related party totals as shown on our Statements of Consolidated Operations and Comprehensive Income.
(2) This amount is taken directly from our Statements of Consolidated Operations and Comprehensive Income.
(3) This amount is taken directly from the operating activities section of our Statements of Consolidated Cash Flows.
(4) This non-cash amount represents our share of the value of the operating leases contributed by EPCO to the Operating Partnership for which EPCO has retained the cash payment obligation (the "retained leases", see Note 14). This amount is taken from the operating activities section ("Operating lease expense paid by EPCO" line item) of our Statements of Consolidated Cash Flows.
(5) This non-cash amount represents a minority interest holder's share of the value of the retained leases. This amount is a component of "Contributions from minority interests" as shown in the financing activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our measurement of total segment gross operating margin to consolidated income before provision for income taxes and minority interest follows:

	For Year Ended December 31,		
	2003	2002	2001
Operating income	$ 248,104	$ 194,307	$ 286,849
Adjustments to reconcile operating income to total gross operating margin:			
Depreciation and amortization in operating costs and expenses	115,643	86,028	48,775
Retained lease expense, net in operating costs and expenses	9,094	9,125	10,414
Loss (gain) on sale of assets in operating costs and expenses	(16)	(1)	(390)
Selling, general and administrative costs	37,590	42,890	30,296
Total segment gross operating margin	$ 410,415	$ 332,349	$ 375,944

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

	Operating Segments					Adjs.	
	Fractionation	Pipelines	Processing	Octane Enhancement	Other	and Elims.	Consol. Totals
Revenues from third parties:							
Year ended December 31, 2003	$ 768,472	$ 622,630	$ 3,338,808	$ 49,654	$ 2,642		$ 4,782,206
Year ended December 31, 2002	592,681	458,427	2,049,202		1,756		3,102,066
Year ended December 31, 2001	301,263	239,489	2,100,224		937		2,641,913
Revenues from related parties:							
Year ended December 31, 2003	2,302	245,992	315,931				564,225
Year ended December 31, 2002	19,121	161,727	301,747		122		482,717
Year ended December 31, 2001	23,013	163,941	324,057		1,445		512,456
Intersegment and intrasegment Revenues:							
Year ended December 31, 2003	260,261	173,194	899,025	1,338	424	$(1,334,242)	-
Year ended December 31, 2002	203,750	102,330	604,981		401	(911,462)	-
Year ended December 31, 2001	158,853	89,907	683,524		389	(932,673)	-
Total revenues:							
Year ended December 31, 2003	1,031,035	1,041,816	4,553,764	50,992	3,066	(1,334,242)	5,346,431
Year ended December 31, 2002	815,552	722,484	2,955,930		2,279	(911,462)	3,584,783
Year ended December 31, 2001	483,129	493,337	3,107,805		2,771	(932,673)	3,154,369
Equity income in unconsolidated affiliates:							
Year ended December 31, 2003	3,361	10,543		(27,864)			(13,960)
Year ended December 31, 2002	7,179	19,505		8,569			35,253
Year ended December 31, 2001	6,945	12,742		5,671			25,358
Gross operating margin by individual business segment and in total:							
Year ended December 31, 2003	132,822	282,854	30,328	(32,701)	(2,888)		410,415
Year ended December 31, 2002	129,000	214,932	(17,633)	8,569	(2,519)		332,349
Year ended December 31, 2001	118,610	96,569	154,989	5,671	105		375,944
Segment assets (see Note 6):							
At December 31, 2003	471,221	2,188,694	163,199	42,220	23,739	74,432	2,963,505
At December 31, 2002	444,016	2,166,524	134,237		16,825	49,237	2,810,839
Investments in and advances to unconsolidated affiliates (see Note 7):							
At December 31, 2003	88,801	645,958	33,000				767,759
At December 31, 2002	95,467	213,632	33,000	54,894			396,993
Intangible Assets (see Note 8):							
At December 31, 2003	68,553	9,753	188,954	1,633			268,893
At December 31, 2002	71,069	7,895	198,697				277,661
Goodwill (see Note 8):							
At December 31, 2003	81,547	880					82,427
At December 31, 2002	81,547						81,547

In general, our historical operating results and/or financial position have been affected by the following acquisitions since 2001:

- a 50% interest in GulfTerra GP from El Paso in December 2003 for $425 million;
- the Mid-America and Seminole pipeline systems from Williams in July 2002 for $1.2 billion;
- a Mont Belvieu, Texas propylene fractionation business from Diamond-Koch in February 2002 for $239 million;
- a Mont Belvieu, Texas NGL and petrochemical storage business from Diamond-Koch in January 2002 for $129.6 million;
- the Acadian Gas pipeline system from Shell in April 2001 for $243.7 million; and
- equity interests in four Gulf of Mexico natural gas pipelines from affiliates of El Paso in January 2001 for $113 million.

These acquisitions were accounted for as purchases and therefore operating results of these acquired entities are included in our financial results prospectively from the purchase date.

During 2002, we recognized a loss of $51.3 million from our Processing segment's commodity hedging activities that was recorded as an increase in our operating costs and expenses which reduced segment gross operating margin. During 2001, we posted income of $101.3 million from this segment's commodity hedging activities, which served to reduce operating costs and expenses and increase segment gross operating margin. See Note 18 for additional information regarding our use of financial instruments.

Due to a 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 and is recorded as a component of "Equity in income (loss) of unconsolidated affiliates" in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2003.

21. CONDENSED FINANCIAL INFORMATION OF OPERATING PARTNERSHIP

The Operating Partnership and its subsidiaries conduct substantially all of our business. We have no independent operations and no material assets outside of those of the Operating Partnership. In December 2003, we restructured our General Partner's ownership interest in us and our Operating Partnership from a 1% ownership in us and 1.0101% ownership in the Operating Partnership to a 2% ownership in us. As a result, our effective ownership in the Operating Partnership increased from 98.9899% to 100%. For additional information regarding our capital structure, see Note 10.

The Operating Partnership has outstanding publicly traded debt securities consisting of its Senior Notes A, B, C and D. We act as guarantor of all of our Operating Partnership's consolidated debt obligations (including its publicly-traded debt securities), with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. Our guarantee of the Operating Partnership's debt obligations is full and unconditional. For additional information regarding our consolidated debt obligations, see Note 9.

The number and dollar amount of reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. The primary reconciling items between the consolidated balance sheet of the Operating Partnership and our consolidated balance sheet are the treasury units we own directly and minority interest. The differences in consolidated net income are primarily dividends recognized by the 1999 Trust (which are eliminated in consolidation) and minority interest. The minority interest differences are attributable to the General Partner's 1.0101% ownership of the Operating Partnership prior to December 2003.

The following tables show condensed financial information for the Operating Partnership for the periods and at the dates indicated:

Consolidated Balance Sheet Data:

	December 31, 2003	December 31, 2002
ASSETS		
Current assets	$ 687,530	$ 638,857
Property, plant and equipment, net	2,963,505	2,810,839
Investments in and advances to unconsolidated affiliates, net	767,759	396,993
Intangible assets, net	268,893	277,661
Goodwill	82,427	81,547
Deferred tax asset	10,437	15,846
Other assets	22,610	9,818
Total	$ 4,803,161	$ 4,231,561
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 1,093,747	$ 721,360
Long-term debt	1,899,548	2,231,463
Other long-term liabilities	14,081	7,666
Minority interest	89,216	59,336
Partners' equity	1,706,569	1,211,736
Total	$ 4,803,161	$ 4,231,561
Total Operating Partnership debt obligations guaranteed by us	$ 2,114,000	$2,200,000

Consolidated Statements of Operations Data:

	For Year Ended December 31, 2003	2002	2001
Revenues	$ 5,346,431	$ 3,584,783	$ 3,154,369
Costs and expenses	5,083,701	3,425,503	2,893,394
Equity in income (loss) of unconsolidated affiliates	(13,960)	35,253	25,358
Operating income	248,770	194,533	286,333
Other income (expense)	(133,798)	(93,810)	(41,471)
Income before provision of income taxes and minority interest	114,972	100,723	244,862
Provision for income taxes	(5,293)	(1,634)	
Income before minority interest	109,679	99,089	244,862
Minority interest	(3,095)	(2,137)	(144)
Net income	$ 106,584	$ 96,952	$ 244,718

22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table contains selected quarterly financial data for 2003 and 2002 (dollars in thousands, except per unit amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2002:				
Revenues	$ 662,054	$ 786,257	$ 943,313	$ 1,193,159
Operating income (loss)	(1,233) [1,2]	39,930 [2]	68,325 [2]	87,285 [2]
Net income (loss)	(17,203) [1]	22,320	34,850 [3]	55,533
Comprehensive income (loss)	(17,203) [1]	22,320	34,850 [3]	51,973
Net income (loss) per unit, basic	$ (0.13) [1]	$ 0.14	$ 0.20	$ 0.30
Net income (loss) per unit, diluted	$ (0.13) [1]	$ 0.11	$ 0.18	$ 0.28
For the Year Ended December 31, 2003:				
Revenues	$ 1,481,586	$ 1,210,659	$ 1,234,780	$ 1,419,406
Operating income	85,032	66,348	30,622 [4]	66,102
Net income (loss)	40,505	33,105	(3,261) [4]	34,197
Comprehensive income (loss)	49,351	33,008	(3,360) [4]	34,097
Net income (loss) per unit, basic	$ 0.20	$ 0.15	$ (0.04) [4]	$ 0.13
Net income (loss) per unit, diluted	$ 0.19	$ 0.14	$ (0.04) [4]	$ 0.13

(1) We recorded an operating loss and net loss for the first quarter of 2002 primarily due to $45.1 million of commodity hedging losses within our Processing segment caused by an unexpected increase in natural gas prices. Overall, we recorded $51.3 million of such losses during 2002.

(2) Beginning in the first quarter of 2003, we reclassified certain expenses that had been a component of other expenses in our Statements of Consolidated Operations to operating expenses within our Other segment. As a result of this reclassification, operating income was reduced by $129 thousand for the first quarter of 2002; $34 thousand for the second quarter of 2002; $31 thousand for the third quarter of 2002; and by $84 thousand for the fourth quarter of 2002. This reclassification had no effect on reported 2002 quarterly net income or loss, comprehensive income or loss, or earnings per unit amounts.

(3) Operating income, net income and comprehensive income beginning with the third quarter of 2002 increased as a result of our acquisition of interests in the Mid-America and Seminole pipelines in July 2002.

(4) Equity earnings from BEF for the third quarter of 2003 include a $22.5 million charge related to an asset impairment. This non-cash charge resulted in our posting a net loss for the quarter.

Market and Cash Distribution History for Common Units and Related Unitholder Matters

Our common units are traded on the NYSE under the symbol "EPD." The following table sets forth, for the periods indicated, the high and low closing sales price ranges for the common units, as reported on the NYSE Composite Transaction Tape, and the amount, record date and payment date of the quarterly cash distributions paid per common unit.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit (1)	Record Date	Payment Date
2002					
1st Quarter	$ 25.800	$ 22.945	$ 0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	$ 24.500	$ 16.250	$ 0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter	$ 22.230	$ 15.000	$ 0.3450	Oct. 31, 2002	Nov. 12, 2002
4th Quarter	$ 19.800	$ 16.410	$ 0.3450	Jan. 31, 2003	Feb. 12, 2003
2003					
1st Quarter	$ 21.000	$ 17.850	$ 0.3625	Apr. 30, 2003	May 12, 2003
2nd Quarter	$ 24.690	$ 20.620	$ 0.3625	Jul. 31, 2003	Aug. 11, 2003
3rd Quarter	$ 24.100	$ 20.250	$ 0.3725	Oct. 31, 2003	Nov. 12, 2003
4th Quarter (2)	$ 24.980	$ 20.760	$ 0.3725	Jan. 30, 2004	Feb. 11, 2004

(1) For each quarter, we paid an identical cash distribution on all outstanding subordinated units. The remaining outstanding subordinated units converted into an equal number of common units on August 1, 2003. For additional information regarding the subordinated units, please read Note 10 of the Notes to Consolidated Financial Statements.
(2) Our Class B special units received quarterly cash distributions equal to those paid to common units beginning with the fourth quarter of 2003 distribution paid in February 2004. For additional information regarding the Class B special units, please read Note 10 of the Notes to Consolidated Financial Statements.

The quarterly cash distribution amounts shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., payments to our limited partners) occur within 45 days after the end of such quarter. Although the payment of such quarterly distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future. We have agreed in the merger agreement with GulfTerra, subject to the terms of our partnership agreement, to increase the quarterly cash distribution for the quarterly distribution date immediately following the closing of the merger to at least $0.395 per unit, or $1.58 per common unit on an annualized basis.

As of February 24, 2004, there were 39,642 beneficial owners of our common units, which includes an estimated 351 unitholders of record.

Issuance of Class B special units in December 2003

On December 17, 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO, for $100 million in a private transaction that was exempt from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof. The purchase price for the Class B special units was $22.6575 per unit, representing a 5% discount from the $23.85 closing price of our common units on the NYSE on December 16, 2003. The 5% discount was consistent with the 5% discount available to all our unitholders under our distribution reinvestment plan. The Class B special units have rights identical to our common units with respect to distributions and other matters. However, the Class B special units do not have voting rights and are not deemed to be outstanding for purposes of determining whether a quorum is present or whether the approval of the requisite number of holders of our units has been obtained. The Class B special units are convertible into common units on a one-for-one basis upon the receipt of approval of holders of not less than a majority of our common units (not including for this purpose the Class B special units) present and entitled to vote at a meeting of our common unitholders or by the holders of a majority of our common units (not including for this purpose the Class B special units) pursuant to written consents. We will request that our common unitholders approve the conversion of all of the Class B special units into common units at the special meeting that will be held to approve our merger with GulfTerra.

Common Units Authorized for Issuance Under Equity Compensation Plans

For information regarding securities authorization under our equity compensation plans, please read Item 12 of our 2003 Form 10-K filed with the Securities and Exchange Commission.

Repurchase of Common Units during 2003

We did not repurchase any of our common units during 2003. Previously, on December 23, 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the two-for-one unit split in May 2002). As of December 31, 2003, we and our affiliates are authorized to repurchase up to 618,400 additional common units under this repurchase program. Common units repurchased under this program are classified as treasury units.

EMPLOYEES

We do not have any employees. EPCO employs most of the persons necessary for the operation of our business. At December 31, 2003, EPCO had approximately 1,325 employees involved in the management and operations of our business, none of whom where members of a union. We fully reimburse EPCO for the costs of approximately 1,220 of these employees, with the remainder of this group covered under the fixed-fee payments we made under the Administrative Services Agreement prior to January 1, 2004 (for a detailed discussion of the Administrative Services Agreement, please read Note 14 beginning on page 87 of this annual report). In addition to EPCO employees, we have engaged approximately 125 contract maintenance and other personnel who support our operations.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND RISK FACTORS

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "intend," "could," "believe," "may" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our General Partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please read our summarized "*Risk Factors*" in our 2003 Form 10-K filed with the Securities and Exchange Commission.

ENTERPRISE PRODUCTS PARTNERS L.P.
Supplemental Information — Reconciliation of GAAP Financial Statements to Non-GAAP Financial Measures

	For the Year Ended December 31,				
	2003	2002	2001	2000	1999
Reconciliation of Non-GAAP "EBITDA" to GAAP "Net Income" and GAAP "Operating Activities Cash Flows"					
Net Income	$ 104,546	$ 95,500	$ 242,178	$ 220,506	$ 120,295
Adjustments to reconcile EBITDA to Net Income:					
Interest expense	140,806	101,580	52,456	33,329	16,439
Provision for income taxes	5,293	1,634			
Depreciation and amortization (excluding amortization component in interest expense)	115,801	86,106	51,116	37,310	23,793
EBITDA	$ 366,446	$ 284,820	$ 345,750	$ 291,145	$ 160,527
Reconciliation of "EBITDA" to "Operating Activities Cash Flows":					
Interest expense	(140,806)	(101,580)	(52,456)	(33,329)	(16,439)
Amortization in interest expense	12,634	8,819	787	3,735	1,522
Provision for income taxes	(5,293)	(1,634)			
Earnings from unconsolidated affiliates	13,960	(35,253)	(25,358)	(24,119)	(13,477)
Distributions from unconsolidated affiliates	31,882	57,662	45,054	37,267	6,008
Loss (gain) on sale of assets	(16)	(1)	(390)	2,270	123
Provision for impairment of asset	1,200				
Operating lease expense paid by EPCO (excluding minority interest portion)	9,010	9,033	10,309	10,537	10,557
Other expenses paid by EPCO (excluding minority interest portion)	436				
Minority interest	3,859	2,947	2,472	2,253	1,226
Deferred income tax expense	10,534	2,080			
Changes in fair market value of financial instruments	(29)	10,213	(5,697)		
Net effect of changes in operating accounts	120,888	92,655	(37,143)	71,111	27,906
Operating Activities Cash Flows	$ 424,705	$ 329,761	$ 283,328	$ 360,870	$ 177,953
Reconciliation of Non-GAAP "Distributable Cash Flow" to GAAP "Net Income" and GAAP "Operating Activities Cash Flows"					
Net Income	$ 104,546	$ 95,500	$ 242,178	$ 220,506	$ 120,295
Adjustments to reconcile Distributable Cash Flow to Net Income:					
Operating lease expense paid by EPCO (excluding minority interest portion)	9,010	9,033	10,309	10,537	10,557
Operating lease expense paid by EPCO (minority interest portion)	84	92	105	107	108
Other expenses paid by EPCO (excluding minority interest portion)	436				
Other expenses paid by EPCO (minority interest portion0	6				
Earnings from unconsolidated affiliates	13,960	(35,253)	(25,358)	(24,119)	(13,477)
Distributions from unconsolidated affiliates	31,882	57,662	45,054	37,267	6,008
Provision for impairment of asset	1,200				
Loss (gain) on sale of assets	(16)	(1)	(390)	2,270	123
Proceeds from sale of assets	212	165	568	92	8
Changes in fair market value of financial instruments	(29)	10,213	(5,697)		
Depreciation and amortization	128,435	94,925	51,903	41,045	25,315
Sustaining capital expenditures	(20,313)	(7,201)	(5,994)	(3,548)	(2,440)
Collection of notes receivable from unconsolidated affiliates				6,519	19,979
Non-cash reduction in reserves established for Enron bankruptcy recorded as a component of changes in operating accounts	(2,073)		(11,246)		
General Partner minority interest in net income	892	979	2,472	2,253	1,229
Distributable Cash Flow	$ 268,232	$ 226,114	$ 303,904	$ 292,929	$ 167,705
Reconciliation of "Distributable Cash Flow" to "Operating Activities Cash Flows"					
Sustaining capital expenditures	20,313	7,201	5,994	3,548	2,440
Deferred income tax expense	10,534	2,080			
Proceeds from sale of assets	(212)	(165)	(568)	(92)	(8)
Minority interest in earnings not included in calculation of Distributable Cash Flow	2,967	1,968			(3)
Minority interest of General Partner in subsidiary's allocation of leases and other expenses paid by EPCO	(90)	(92)	(105)	(107)	(108)
Non-cash reduction in reserves established for Enron bankruptcy recorded as a component of changes in operating accounts	2,073		11,246		
Collection of notes receivable from unconsolidated affiliates recorded as a component of financing activities cash flows				(6,519)	(19,979)
Net effect of changes in operating accounts	120,888	92,655	(37,143)	71,111	27,906
Operating Activities Cash Flows	$ 424,705	$ 329,761	$ 283,328	$ 360,870	$ 177,953

DIRECTORS AND OFFICERS OF ENTERPRISE PRODUCTS GP, LLC

Directors
Dan L. Duncan (1) (3)
Chairman of the Board, Enterprise Products GP, LLC

O.S. Andras (1) (3)
President and Chief Executive Officer, Enterprise Products GP, LLC

Dr. Ralph S. Cunningham (2)
former President and Chief Executive Officer, CITGO Petroleum Corporation

Lee W. Marshall, Sr. (2)
Managing Partner and Principal Owner, Bison Resources, LLC

Richard S. Snell (2)
Partner, Thompson Knight, LLP

Officers in addition to Directors
Richard H. Bachmann (1) (3)
Executive Vice President, Chief Legal Officer and Secretary, Enterprise Products GP, LLC

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Executive Vice President and Chief Financial Officer

William D. Ray (3)
Executive Vice President, Marketing and Supply

A.J. "Jim" Teague (3)
Executive Vice President

Lynn L. Bourdon, III (3)
Senior Vice President, Marketing and Supply

James A. Cisarik (3)
Senior Vice President, Natural Gas Assets

James M. Collingsworth (3)
Senior Vice President, NGL Assets

Charles E. Crain (3)
Senior Vice President, Operations, Engineering, Safety and Environmental

William Ordemann (3)
Senior Vice President, NGL Assets

G. H. Radtke (3)
Senior Vice President, Petrochemical Assets

Charles M. Brabson
Vice President, Engineering

Frank A. Chapman
Vice President, Corporate Risk

DIRECTORS AND OFFICERS OF ENTERPRISE PRODUCTS GP, LLC (continued)

W. Randall Fowler [3]
Vice President and Treasurer

James D. Gernentz
Vice President, Texas Operations

Vance L. Harrington
Vice President, Wholesale Propane Marketing

Theodore Helfgott, Ph.D.
Vice President, Environmental Administration

Terrance L. Hurlbert
Vice President and General Manager, Operations

Michael J. Knesek [3]
Vice President, Controller and Principal Accounting Officer

Earl M. Lambert, II
Vice President and Chief Information Officer

James N. McGrew
Vice President, Accounting

Rudy A. Nix
Vice President, Distribution

Daniel P. Olsen
Vice President, Business Support

John L. Tomerlin
Vice President, Human Resources

A. Monty Wells
Vice President, Marketing and Supply

John E. Smith, II
Assistant Secretary

Patricia Totten
Assistant Secretary

Thomas M. Zulim
Assistant Secretary

(1) Member of Executive Committee
(2) Member of Audit Committee
(3) Executive Officer

Glossary

The following abbreviations, acronyms or terms used in this Annual Report are defined below:

Acadian Gas	Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001
Accum. OCI	Accumulated Other Comprehensive Income
Administrative Services Agreement	First Amended and Restated Administrative Services Agreement, effective as of January 1, 2004, among EPCO, the Company, the Operating Partnership, the General Partner and the OLP General Partner (formerly, the "EPCO Agreement")
AICPA	American Institute of Certified Public Accountants
BBtus	Billion British thermal units, a measure of heating value
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BEF	Belvieu Environmental Fuels
Belle Rose	Belle Rose NGL Pipeline LLC, an equity investment
BP	BP PLC and affiliates
BPD	Barrels per day
BRF	Baton Rouge Fractionators LLC, an equity investment
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity investment
Burlington Resources	Burlington Resources Inc. and its affiliates
CEO	Chief Executive Officer
CFO	Chief Financial Officer
ChevronTexaco	ChevronTexaco Corp. and its affiliates
CMAI	Chemical Market Associates, Inc.
Cogeneration	Cogeneration is the simultaneous production of electricity and heat using a single fuel such as natural gas.
Company	Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Operating Partnership
ConocoPhillips	ConocoPhillips Petroleum Company and its affiliates
CPG	Cents per gallon
Deepwater	Deepwater refers to oil and gas production areas located at depths of 1,000 feet or more such as those found in the Gulf of Mexico.
Diamond-Koch	Refers to common affiliates of both Valero Energy Corporation and Koch Industries, Inc.
DIB	Deisobutanizer
Dixie	Dixie Pipeline Company, an equity investment
DRP	Distribution Reinvestment Plan
Duke	Duke Energy Corporation and its affiliates
El Paso	El Paso Corporation and its affiliates
EPA	Environmental Protection Agency
EPCO	Enterprise Products Company, an affiliate of the Company and our ultimate parent company (including its affiliates)
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the "Operating Partnership")
Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity investment
FASB	Financial Accounting Standards Board
Feedstock	A raw material required for an industrial process such as in petrochemical manufacturing
FERC	Federal Energy Regulatory Commission
Forward sales contracts	The sale of a commodity or other product in a current period for delivery in a future period.

Fractionation	For a discussion of our Fractionation segment, please read "*The Company's Operations – Fractionation*" beginning on page 8 of this annual report.
FTC	U.S. Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States of America
General Partner	Enterprise Products GP, LLC, the general partner of the Company
GulfTerra	GulfTerra Energy Partners, L.P. (for a discussion of GulfTerra, please read "*The Company's Operations – Recent Developments*" beginning on page 19 of this annual report.
GulfTerra GP	GulfTerra Energy Company, L.L.C., the general partner of GulfTerra
HSC	Denotes our Houston Ship Channel pipeline system
ICA	Interstate Commerce Act
IRS	Internal Revenue Service
Isomerization	For a discussion of the isomerization process, please read "*The Company's Operations – Fractionation – Isomerization*" beginning on page 8 of this annual report.
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity investment
LIBOR	London interbank offered rate
MBA	Mont Belvieu Associates, see "MBA acquisition" below
MBA acquisition	Refers to the acquisition of Mont Belvieu Associates' remaining interest in the Mont Belvieu NGL fractionation facility in 1999
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
Mid-America	Mid-America Pipeline Company, LLC
Midstream Energy Assets	The intermediate segments of the energy industry downstream of oil and gas production and upstream of end user consumption. These segments provide services to producers and consumers of energy. These services generally include but are not limited to natural gas gathering, processing and wholesale marketing and NGL fractionation, transportation and storage.
MMBbls	Millions of barrels
MMBtus	Million British thermal units, a measure of heating value
Mont Belvieu	Mont Belvieu, Texas
Moody's	Moody's Investors Service
MTBE	Methyl tertiary butyl ether
Natural gas processing	For a discussion of our natural gas processing business, please read "*The Company's Operations – Processing*" beginning on page 4 of this annual report.
Nemo	Nemo Gathering Company, LLC, an equity investment
Neptune	Neptune Pipeline Company, L.L.C., an equity investment
NGL or NGLs	Natural gas liquid(s)
NGL marketing activities	For a discussion of our NGL marketing activities, please read "*The Company's Operations – Processing*" beginning on page 4 of this annual report.
NYSE	New York Stock Exchange
Ocean Breeze	Ocean Breeze Pipeline Company, LLC, an equity investment (merged into Neptune during fourth quarter of 2001)
OLP General Partner	Enterprise Products OLPGP, Inc., the general partner of the Operating Partnership and a wholly-owned subsidiary of the Company
OPIS	Oil Price Information Service
Operating Partnership	Enterprise Products Operating L.P. and its affiliates
OTC	Olefins Terminal Corporation
Petrochemical marketing	For a discussion of our petrochemical marketing activities, please read "*The Company's Operations – Fractionation – Propylene fractionation*" beginning on page 8 of this annual report.
Promix	K/D/S Promix LLC, an equity investment

Glossary (continued)

PTR	Refers to "plant thermal reduction." For a discussion of PTR, please read "*The Company's Operations – Processing*" beginning on page 4 of this annual report.
SEC	U.S. Securities and Exchange Commission
Seminole	Seminole Pipeline Company
SFAS	Statement of Financial Accounting Standards issued by the FASB
Shell	Shell Oil Company, its subsidiaries and affiliates
Splitter III	Refers to the propylene fractionation facility we acquired from Diamond-Koch
Spot market	Refers to a market where buyers and sellers consummate routine transactions where performance by both parties is short-term in nature and prices are based on market conditions at the time the transaction is executed. For a discussion of "spot market" transactions, please read "*The Company's Operations – Fractionation – Propylene fractionation*" beginning on page 8 of this annual report.
Starfish	Starfish Pipeline Company, LLC, an equity investment
Straddle plants	A natural gas processing facility situated on a pipeline that is the sole inlet and outlet for the processing facility
Sun	Sunoco Inc. and its affiliates
Throughput	Refers to the physical movement of volumes through a pipeline
TNGL acquisition	Refers to the acquisition of Tejas Natural Gas Liquids, LLC, an affiliate of Shell, in 1999
Tri-States	Tri-States NGL Pipeline LLC, an equity investment
VESCO	Venice Energy Services Company, LLC, a cost method investment
Williams	The Williams Companies, Inc. and its affiliates
Wilprise	Wilprise Pipeline Company, LLC
1998 Trust	Duncan Family 1998 Trust (formerly Enterprise Products 1998 Unit Option Plan Trust), an affiliate of EPCO
1999 Trust	EPOLP 1999 Grantor Trust, a subsidiary of EPOLP
2000 Trust	Duncan Family 2000 Trust (formerly Enterprise Products 2000 Rabbi Trust), an affiliate of EPCO

COMPANY INFORMATION

STOCK EXCHANGE AND COMMON UNIT TRADING PRICES

Enterprise Products Partners L.P. Common Units trade on the New York Stock Exchange under the ticker symbol EPD. Enterprise had 213,366,760 Common Units and 4,413,549 Class B Special Units outstanding at December 31, 2003. For a complete description of these units, see page 80. For a table of the high and low market prices of the Common Units by quarter, see page 109.

CASH DISTRIBUTIONS

Enterprise has paid 22 consecutive quarterly cash distributions to Unitholders since its public offering of Common Units in 1998. On January 14, 2004, the Company declared a quarterly distribution of $0.3725 per unit. This distribution was made to Unitholders of record as of January 30, 2004. For a summary of the cash distributions paid, see page 84.

INDEPENDENT AUDITORS

Deloitte & Touche, LLP
Suite 2300
333 Clay Street
Houston, Texas 77002-4196

PUBLICLY TRADED PARTNERSHIP ATTRIBUTES

Enterprise Products Partners L.P. is a publicly traded master limited partnership, which operates in the following ways that are different from a publicly traded stock corporation.

Unitholders own limited partnership units instead of shares of common stock and receive cash distributions rather than dividends.

A partnership generally is not a taxable entity and does not pay federal income taxes. All of the annual income, gains, losses, deductions or credits flow through the partnership to the unitholders on a per unit basis. The unitholders are required to report their allocated share of these amounts on their income tax returns whether or not any cash distributions are made by the partnership to its unitholders.

Cash distributions paid by a partnership to a unitholder are generally not taxable, unless the amount of any cash distributed is in excess of the unitholder's adjusted basis in their partnership interest. Enterprise provides each unitholder a Schedule K-1 tax package that includes their allocated share of reportable partnership items and other partnership information necessary to be reported on state and federal income tax returns. The K-1 provides a unitholder required tax information for their ownership interest in the partnership similar to the Form 1099DIV a stockholder of a corporation would receive.

TRANSFER AGENT, REGISTRAR AND CASH DISTRIBUTION PAYING AGENT

Mellon Investor Services LLC
Overpeck Center
85 Challenger Road
Ridgefield Park, NJ 07660
(800) 635-9270
www.melloninvestor.com

ADDITIONAL INVESTOR INFORMATION

Additional information about Enterprise Products Partners L.P., including our SEC annual report on form 10-K, can be obtained by contacting Investor Relations at (713) 880-6812, writing to the Company's mailing address provided below or accessing the company's internet home page at www.epplp.com.

K-1 INFORMATION

Information concerning the company's K-1s can be obtained by calling toll free (800) 599-9985.

PARTNERSHIP OFFICES

Enterprise Products Partners L.P.
2727 North Loop West, Suite 700
Houston, TX 77008-1044
Mailing Address:
P.O. Box 4324
Houston, TX 77210-4324
(713) 880-6500

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2727 North Loop West, Suite 700
Houston, TX 77008-1044