Enterprise Products Partners L.P.
Consolidated Financial Statements
for the Years Ended December 31, 2002 and 2001

Index to Financial Statements

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 98.9899% 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 1.0% interest in us and a 1.0101% interest in our Operating Partnership. 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 the audited consolidated financial statements and accompanying footnotes. In addition, the reader should review "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" on page 96 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*" beginning on page 41. For a discussion of related-party matters, including our relationship with Shell, please read footnote 14 titled "Related Party Transactions" in the Notes to Consolidated Financial Statements.

Our results of operations

We have five reportable 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 interest in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and various operational support activities.

Our management evaluates segment performance based on our measurement of segment gross operating margin. Gross operating margin for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and selling, general and administrative expenses. Segment gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges.

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 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, see the Notes to our Consolidated Financial Statements.

Under the terms of an agreement we executed with EPCO at our formation in 1998 (the "EPCO Agreement", see footnote 14 titled "Related Party Transactions" in the Notes to Consolidated Financial Statements), EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for one dollar per year (the "retained leases"). EPCO holds these items pursuant to operating leases for which it has agreed to retain the corresponding 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 partnership. 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. These purchase options are based on the estimated fair market values of the equipment at the end of their respective lease terms. For additional information regarding these retained leases, see footnote 14, "Related Party Transactions" and our "*Capital spending*" disclosure on page 33.

The following table shows our measurement of total gross operating margin for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2002	**2001**	**2000**
Revenues *(1)*	$ 3,584,783	$ 3,154,369	$ 3,049,020
Operating costs and expenses *(1)*	(3,382,561)	(2,861,743)	(2,801,060)
Equity in income of unconsolidated affiliates *(2)*	35,253	25,358	24,119
Subtotal	237,475	317,984	272,079
Add: Depreciation and amortization in operating costs and expenses *(3)*	86,029	48,775	35,621
Retained lease expense, net in operating costs and expenses *(4)*	9,124	10,414	10,645
(Gain) loss on sale of assets in operating costs and expenses *(3)*	(1)	(390)	2,270
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615

(1) Amounts are comprised of both third party and related party totals from the Statements of Consolidated Operations and Comprehensive Income
(2) Amount taken from Statements of Consolidated Operations and Comprehensive Income
(3) Amount taken from Statements of Consolidated Cash Flows
(4) Amount represents leases paid by EPCO and the related contribution by the minority interest as reflected on the Statements of Consolidated Cash Flows

Our measurement of gross operating margin amounts by segment along with a reconciliation to consolidated operating income were as follows for the periods indicated (dollars in thousands):

	For Year Ended December 31,		
	2002	**2001**	**2000**
Gross operating margin by segment:			
Pipelines	$ 214,932	$ 96,569	$ 56,099
Fractionation	129,000	118,610	129,376
Processing	(17,633)	154,989	122,240
Octane enhancement	8,569	5,671	10,407
Other	(2,241)	944	2,493
Total segment gross operating margin	332,627	376,783	320,615
Depreciation and amortization	(86,029)	(48,775)	(35,621)
Retained lease expense, net	(9,124)	(10,414)	(10,645)
Gain (loss) on sale of assets	1	390	(2,270)
Selling, general and administrative expenses	(42,890)	(30,296)	(28,345)
Consolidated operating income	$ 194,585	$ 287,688	$ 243,734

Our significant plant production and other volumetric data were as follows for the periods indicated:

	For Year Ended December 31,		
	2002 *(1)*	**2001** *(1)*	**2000** *(1)*
MBPD, Net			
Propylene Fractionation	55	31	33
Isomerization	84	80	74
NGL Fractionation	235	204	213
Equity NGL Production	73	63	72
Octane Enhancement	5	5	5
NGL and petrochemical pipelines *(2)*	1,357	453	367
BBtus per day, Net			
Natural gas pipelines	1,207	1,349	n/a
Equivalent MBPD, Net			
NGL, petrochemical and natural gas pipelines *(3)*	1,675	808	367

(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

The following table illustrates selected average quarterly prices for natural gas, crude oil and selected NGL and petrochemical products since the first quarter of 2000:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound
	(a)	(b)	(a)	(a)	(a)	(a)	(a)	(a)
2000								
1st Quarter	$2.49	$28.84	$0.38	$0.54	$0.64	$0.64	$0.21	$0.17
2nd Quarter	$3.41	$28.79	$0.36	$0.52	$0.60	$0.68	$0.26	$0.24
3rd Quarter	$4.22	$31.61	$0.40	$0.60	$0.68	$0.67	$0.26	$0.18
4th Quarter	$5.22	$31.98	$0.49	$0.67	$0.75	$0.73	$0.24	$0.19
Average	$3.84	$30.31	$0.41	$0.58	$0.67	$0.68	$0.24	$0.19
2001								
1st Quarter	$7.05	$28.77	$0.49	$0.63	$0.70	$0.74	$0.23	$0.17
2nd Quarter	$4.65	$27.86	$0.37	$0.50	$0.56	$0.66	$0.19	$0.12
3rd Quarter	$2.90	$26.64	$0.27	$0.41	$0.49	$0.49	$0.16	$0.13
4th Quarter	$2.43	$21.04	$0.21	$0.34	$0.40	$0.39	$0.18	$0.13
Average	$4.26	$26.07	$0.33	$0.47	$0.54	$0.57	$0.19	$0.14
2002								
1st Quarter	$2.34	$21.41	$0.22	$0.30	$0.38	$0.44	$0.16	$0.12
2nd Quarter	$3.38	$26.26	$0.26	$0.40	$0.48	$0.51	$0.20	$0.17
3rd Quarter	$3.16	$28.30	$0.26	$0.42	$0.52	$0.58	$0.21	$0.16
4th Quarter	$3.99	$28.33	$0.31	$0.49	$0.60	$0.63	$0.20	$0.15
Average	$3.22	$26.08	$0.26	$0.40	$0.50	$0.54	$0.19	$0.15

(a) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including OPIS and CMAI
(b) Crude Oil price is representative of the index price for West Texas Intermediate

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

The following table shows our consolidated revenues, costs and expenses, and operating income for the years ended December 31, 2002 and 2001 (dollars in thousands):

	For Year Ended December 31, 2002	2001
Revenues	$ 3,584,783	$ 3,154,369
Costs and expenses	$ 3,425,451	$ 2,892,039
Operating income	$ 194,585	$ 287,688

Revenues for 2002 increased $430.4 million over those of 2001. The increase is primarily due to acquisitions we completed during 2002 such as the purchase of Mid-America and Seminole from Williams and Splitter III 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 the results of our commodity hedging activities. Operating income decreased $93.1 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 1,669 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 results from 2002 including a full year's results of operations from Acadian Gas, 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 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, see “Quantitative and Qualitative Disclosures about Market Risk on page 44.

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 less 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 $3.2 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.

Year ended December 31, 2001 compared to year ended December 31, 2000

The following table shows our consolidated revenues, costs and expenses, and operating income for the years ended December 31, 2001 and 2000 (dollars in thousands):

	For Year Ended December 31,	
	2001	**2000**
Revenues	$ 3,154,369	$ 3,049,020
Costs and expenses	$ 2,892,039	$ 2,829,405
Operating income	$ 287,688	$ 243,734

Revenues for 2001 increased $105.3 million over those of 2000. The increase in revenue is primarily due to the acquisition of Acadian Gas from Shell during 2001. The higher pipeline revenues were offset by a decline in NGL product prices during 2001 relative to 2000 which lowered revenues from our NGL marketing activities. Costs and expenses during 2001 were $62.6 million higher than 2000 primarily due to the addition of costs and expenses of acquired businesses offset by decreased NGL product purchase prices and improved results from commodity hedging activities. Operating income increased $44.0 million year-to-year primarily as a result of such changes.

Pipelines. Gross operating margin from our Pipelines segment was $96.6 million for 2001 compared to $56.1 million for 2000. On an energy equivalent basis, net pipeline throughput volume for 2001 was 809 MBPD compared to 367 MBPD during 2000. Of the $40.5 million increase in segment gross operating margin, $20.0 million is due to the addition of earnings from natural gas pipelines we acquired during 2001. Specifically, we acquired Acadian Gas from Shell in April 2001 and equity ownership interests in four Gulf of Mexico systems from El Paso in January 2001. The natural gas throughput on these systems accounted for 355 MBPD of the 442 MBPD increase in segment volumes, on an energy equivalent basis.

An additional $12.2 million of the year-to-year increase in segment gross operating margin is attributable to our Lou-Tex NGL pipeline, which was completed and began operations during the fourth quarter of 2000. Gross operating margin from our Houston Ship Channel NGL import facility and related HSC pipeline increased $5.2 million in 2001 due to a rise in commercial butane imports related to isobutane production. The increase in NGL import activity and related pipeline movements accounted for 63 MBPD of the year-to-year increase in segment volumes.

Fractionation. Gross operating margin from our Fractionation segment was $118.6 million for 2001 compared to $129.4 million for 2000. Our propylene fractionation volumes declined slightly in 2001 to 31 MBPD from 33 MBPD in 2000. Gross operating margin from propylene fractionation increased $0.3 million in 2001 over 2000 due to additional margins from BRPC, which did not commence operations until the third quarter of 2000. Our isomerization business posted an $8.4 million increase in gross operating margin during 2001 when compared to 2000. Isomerization volumes increased to 80 MBPD during 2001 from 74 MBPD during 2000. The increase in isomerization earnings is primarily due to certain of our isomerization fees being indexed to historical natural gas prices (which were higher in 2001 relative to 2000). Lastly, gross operating margin from our NGL fractionation business in 2001 declined $21.0 million from 2000 levels, primarily as a result of lower in-kind fees at Norco. In-kind fee arrangements expose us to commodity price risk in that our revenues are dependent upon NGL market prices, which were generally lower in 2001 as compared to 2000. NGL fractionation volumes decreased to 204 MBPD during 2001 from 213 MBPD during 2000. The year-to-year decrease in NGL fractionation volumes is primarily due to lower mixed NGL extraction rates at regional gas plants during early 2001, which in turn was caused by higher natural gas prices.

Processing. Gross operating margin from our Processing segment was $155.0 million for 2001 compared to $122.2 million for 2000. Our equity NGL production decreased 9 MBPD to 63 MBPD during 2001 versus 72 MBPD during 2000. The decrease in our equity NGL production rate is primarily due to less favorable gas processing economics during early 2001 caused by higher natural gas prices. Segment gross operating margin for 2001 includes $101.3 million of commodity hedging income, an increase of $74.5 million over such income in 2000. The increase in our commodity hedging income mitigated or exceeded the loss in value of our NGL production caused by commodity price movements during 2001. In addition, our NGL marketing activities benefited from unusually strong demand for propane and isobutane during early and mid-2001.

We are exposed to settlement risk (a form of credit risk) with the counterparties of our financial instruments. On all transactions where we are exposed to settlement risk, we analyze the counterparty's financial condition prior to entering an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. In December 2001, Enron North America (the counterparty to some of our commodity financial instruments) filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As a result, we recorded a charge against earnings of $10.6 million for all amounts owed to us by Enron. The Enron amounts were unsecured and the amount that we may ultimately recover, if any, is not presently determinable.

Octane Enhancement. Our equity earnings from BEF were $5.7 million for 2001 compared to $10.4 million for 2000. The decrease in equity earnings is primarily due to lower MTBE and by-product prices in 2001. On a gross basis, BEF's MTBE production was 14 MBPD during 2001 and 2000.

Other. Gross operating margin from this segment decreased $1.5 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 $30.3 million during 2001 compared to $28.3 million during 2000. The increase is primarily due to the additional staff and resources needed to support our expansion activities resulting from acquisitions and other business development.

Interest expense. Interest expense increased to $52.5 million during 2001 compared to $33.3 million during 2000. The increase is primarily due to debt obligations we incurred as a result of business acquisitions completed during 2001. In addition, income from our interest rate hedging activities (which is recorded as a reduction in interest expense) increased $3.2 million in 2001 when compared to 2000. The change in interest rate hedging results is primarily due to certain elections by counterparties during 2001 and a general decrease in interest rates.

General outlook for 2003

We expect our business to be affected by the following key trends and events during 2003. 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 a result of abnormally high natural gas prices during the first quarter of 2003, we anticipate that NGL extraction rates at natural gas processing plants will be reduced. High natural gas prices may result in the cost of energy consumed by our natural gas processing facilities exceeding the market value of NGLs they extract. During periods of unusually high natural gas prices, we discuss with natural gas producers possible ways to limit the unfavorable impact of these energy costs.
- The expected reduction in NGL extraction rates during the first quarter of 2003 may also result in lower pipeline throughput rates and NGL fractionation volumes.
- As a result of the lower NGL extraction rates noted above, the demand for and price of certain NGL products increased. We expect that gross operating margin for our Processing segment will benefit from these market price increases as NGL inventories held by our NGL marketing group are sold.
- The expansion of our Neptune gas processing facility (which began in October 2002) is expected to be complete during the fourth quarter of 2003. This expansion will increase Neptune's gross gas processing capacity from 0.3 Bcf/d to 0.65 Bcf/d and will increase our NGL production capacity by 25 MBPD.
- In late 2003, Starfish is scheduled to complete construction of a 41-mile Gulf of Mexico natural gas pipeline that will connect its Stingray pipeline to new sources of deepwater Gulf of Mexico natural gas production.
- In March 2003, we completed the purchase of the remaining 50% ownership interests in EPIK from Idemitsu. As a result of this acquisition, segment earnings from NGL export activities will increase beginning in the first quarter of 2003 as we consolidate 100% of this operation.
- We expect a modest decline in demand for isomerization services during 2003 as refiners reduce their MTBE production in advance of California's ban on MTBE (of which isobutane is a feedstock) which takes effect in January 2004. The decline in isobutane demand attributable to MTBE production may be offset by increased demand for isobutane in producing alkylate (which could act as a replacement gasoline additive in place of MTBE).
- As a result of California's switch from using MTBE in its clean fuels program to ethanol in January 2004, we expect that overall demand for MTBE over the course of 2003 will be weaker than in prior years. This development will probably lead to lower MTBE prices which in turn will affect our equity earnings from BEF.

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 and the issuance of additional partnership equity and public and 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.

Operating cash flows primarily reflect the effects of net income adjusted for depreciation and amortization, equity income and cash distributions from unconsolidated affiliates, fluctuations in fair values 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 including fluctuations in NGL and energy prices, competitive practices in the midstream energy industry and the impact of operational and systems 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 NGL products, increased competition from petroleum-based products due to pricing differences or other reasons, could have a negative impact on earnings and thus the availability of cash from operating activities. For a more complete discussion of these and other risk factors pertinent to our businesses, see the section titled "Cautionary Statement Regarding Forward-Looking Information and Risk Factors" on page 96.

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, 2002, we had approximately $2.2 billion outstanding under various debt agreements. On that date, total borrowing capacity under our commercial bank credit facilities was $500 million of which $176 million of capacity was available. For additional information regarding our debt, see "*Our debt obligations*" on page 30.

In February 2001, we filed a universal shelf registration with the SEC covering the issuance of an unspecified amount of partnership equity or public debt obligations (separately or in combination). In October 2002, we sold 9.8 million Common Units under this shelf registration which generated net proceeds to us of approximately $183.3 million before offering expenses. In January 2003, we sold an additional 14.7 million Common Units under this shelf registration which generated $258.9 million in net proceeds before offering expenses. We used net proceeds before offering expenses from both equity issues to reduce debt outstanding under our 364-Day Term Loan and for working capital purposes. Also, in January and February 2003, we completed the issuance of $850 million of private placement debt (Senior Notes C and D) that we expect to convert to public debt. For additional information regarding the general use of proceeds from the Senior Notes C and D and the January 2003 equity offering, see our footnote titled "*Subsequent Events*" in the Notes to Consolidated Financial Statements. In addition, please read the section titled "*Our debt obligations*" within this "*Our liquidity and capital resources*" discussion for information regarding our debt obligations.

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 accordance with Rule 457(p) promulgated under the Securities Act of 1933, as amended, the registration fee associated with the unsold portion of the securities under the shelf registration statement filed in February 2001 was used to offset the registration fee due in connection with our $1.5 billion universal shelf registration statement. As a result, at the time our $1.5 billion shelf registration statement is declared effective by the SEC, the securities remaining under the shelf registration statement filed in February 2001 will be deemed deregistered.

We have the ability to issue an unlimited number of Common Units to finance acquisitions and capital improvements if Adjusted Operating Surplus (as defined within our partnership agreement) for each of the four fiscal quarters immediately preceding the expenditure, on a pro forma basis, would have increased as a result of such expenditure (i.e., would have been accretive on a pro forma basis for each of the quarters in the test). For those acquisitions and other transactions that do not qualify under the aforementioned pro forma "accretive" test, we have 54,550,000 Units available for general partnership purposes during the Subordination Period. The Subordination Period generally extends until the first day of any quarter beginning after June 30, 2003 when certain financial tests have been satisfied. After the Subordination Period expires, we may prudently issue an unlimited number of Units for general partnership purposes that do not meet the pro forma "accretive" test.

If deemed necessary, we believe that additional financing arrangements can be obtained at 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.

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. The following table summarizes the major components of operating cash flows for 2002 and 2001 (dollars in thousands):

	For Year Ended December 31,	
	2002	**2001**
Net income	$ 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	94,925	51,903
Equity in income of unconsolidated affiliates	(35,253)	(25,358)
Distributions received from unconsolidated affiliates	57,662	45,054
Non-cash changes in fair market value of financial instruments	10,213	(5,697)
Other	14,059	12,391
Cash flow from operating activities before changes in operating accounts	$ 237,106	$ 320,471
Net effect of changes in operating accounts	92,655	(37,143)
Operating activities cash flows	$ 329,761	$ 283,328

As shown in the table above, cash flow before changes in operating accounts was an inflow of $237.1 million during 2002 versus $320.5 million during 2001. We believe that cash flow from operating activities before changes in operating accounts is an important measure of our liquidity. We believe it provides an indication of our ability to generate core cash flows from the assets and investments we own or in which we have an interest. 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 see our footnote titled "*Supplemental Cash Flows Disclosure*" in the Notes to Consolidated Financial Statements.

Investing cash flows. During 2002, we used $1.7 billion in cash for investing activities compared to $491.2 million during 2001. 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. 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 9.8 million new Common Units. Net proceeds before offering expenses from the sale of the Common Units were $183.3 million (from which offering expenses of approximately $0.8 million were paid). This amount includes the General Partner's aggregate contribution to us and our Operating Partnership of $3.6 million to maintain its combined 2% general partner interest. Cash distributions to our partners 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 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 issue costs increased $16.2 million year-to-year primarily due to the $15.0 million in fees we paid to banks in July 2002 associated with the short-term financing of the Mid-America and Seminole acquisitions.

Year ended December 31, 2001 compared to year ended December 31, 2000

Operating cash flows. Cash flow from operating activities was an inflow of $283.3 million during 2001 compared to $360.9 million during 2000. The following table summarizes the major components of operating cash flows for 2001 and 2000 (dollars in thousands):

	For Year Ended December 31,	
	2001	**2000**
Net income	$ 242,178	$ 220,506
Adjustments to reconcile net income to cash flows provided by		
(used for) operating activities before changes in operating accounts:		
Depreciation and amortization	51,903	41,045
Equity in income of unconsolidated affiliates	(25,358)	(24,119)
Distributions received from unconsolidated affiliates	45,054	37,267
Non-cash changes in fair market value of financial instruments	(5,697)	
Other	12,391	15,060
Cash flow from operating activities before changes in operating accounts	$ 320,471	$ 289,759
Net effect of changes in operating accounts	(37,143)	71,111
Operating activities cash flows	$ 283,328	$ 360,870

As shown in the table above, cash flow before changes in operating accounts was an inflow of $320.5 million during 2001 versus $289.8 million during 2000. The $30.7 million increase in this element of our operating cash flows was primarily due to improved commodity hedging results offset by an increase in interest expense. The $10.9 million increase in depreciation and amortization is primarily due to businesses we acquired during 2001. 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 see our footnote titled "*Supplemental Cash Flows Disclosure*" in the Notes to Consolidated Financial Statements.

Investing cash flows. During 2001, we used $491.2 million in cash for investing activities compared to $268.8 million during 2000. 2001 reflects the $225.7 million paid to acquire Acadian Gas from Shell and $113.0 million paid to acquire equity interests in four Gulf of Mexico natural gas pipelines from El Paso. During 2001, our capital expenditures were $149.9 million compared to $243.9 for 2000. The majority of capital expenditures made during both periods were for projects within our Pipelines segment.

Financing cash flows. Our financing activities generated $279.5 million of cash receipts in 2001 compared to cash payments of $36.9 million in 2000. Net borrowings for 2001 reflect our issuance of Senior Notes B whereas 2000 includes the issuance of Senior Notes A and the MBFC Loan and the associated repayments on various commercial bank credit facilities. Cash distributions to our partners increased $25.0 million year-to-year primarily due to increases in both the declared quarterly distribution rates and the number of Units eligible for distributions. When compared to 2000, the number of Units eligible for distributions during 2001 increased due to the conversion of 10.0 million of Shell's Special Units to an equal number of Common Units in August 2001.

Our debt obligations

Our debt consisted of the following at (dollars in thousands):

	December 31, 2002	December 31, 2001
Borrowings under:		
364-Day Term Loan, variable rate, due July 2003	$ 1,022,000	
364-Day Revolving Credit facility, variable rate, due November 2004	99,000	
Multi-Year Revolving Credit facility, variable rate, due November 2005	225,000	
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	$ 350,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005	45,000	
Total principal amount	2,245,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,774	1,653
Less unamortized discount on:		
Senior Notes A	(81)	(117)
Senior Notes B	(230)	(258)
Less current maturities of debt	(15,000)	-
Long-term debt	$ 2,231,463	$ 855,278

The table above does not reflect the issuance of our $350 million principal amount Senior Notes C in January 2003 and $500 million principal amount Senior Notes D in February 2003 nor does it reflect the repayment of debt using proceeds from our January 2003 equity offering. We used a combination of proceeds from the issuance of Senior Notes C and D and the January 2003 equity offering to completely repay the 364-Day Term Loan by the end of February 2003 (see the section titled "*General description of debt—364-Day Term Loan*" within this "*Our debt obligations*" discussion for additional information regarding the use of proceeds to extinguish this debt). In addition, also read the section titled "*New debt obligations issued during first quarter of 2003"* within this "*Our debt obligations*" discussion for information regarding our Senior Notes C and D.

As to the assets of our subsidiary, Seminole Pipeline Company, our $2.2 billion in senior indebtedness at December 31, 2002 is structurally subordinated and ranks junior in right of payment to the $45 million of indebtedness of Seminole Pipeline Company. 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, 2002 reflect the classification of such debt obligations at March 7, 2003.

Letters of credit. At December 31, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Revolving Credit facility, of which $2.4 million was outstanding.

Parent-Subsidiary guarantor relationships. Enterprise Products Partners L.P. (the "MLP", on a stand-alone basis) acts as guarantor of certain of the Operating Partnership's debt obligations. These parent-subsidiary guaranty provisions exist under all of our debt obligations with the exception of the Seminole Notes. The Seminole Notes are unsecured obligations solely of Seminole Pipeline Company. If the Operating Partnership were to default on any guaranteed debt obligation, the MLP would be responsible for full payment of that obligation.

General description of debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2002.

364-Day Term Loan. The Operating Partnership entered into a $1.2 billion senior unsecured 364-day term loan to fund the Mid-America and Seminole acquisitions in July 2002. We applied proceeds of $178.8 million from our October 2002 equity offering to partially repay this loan. We used $252.8 million of the $258.9 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 completely repay the 364-Day Term Loan by February 2003. Base variable interest rates under this facility generally bore interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent or (2) a Eurodollar rate. Whichever base interest rate we selected, the rate was increased by an appropriate applicable margin (as defined within the loan agreement). During 2002, the weighted-average interest rate charged was 3.1%. This facility contained various covenants similar to those of our revolving credit facilities. We were in compliance with these covenants at December 31, 2002.

364-Day Revolving Credit facility. In November 2000, we entered in a 364-Day revolving credit agreement. Currently, the stand-alone borrowing capacity under this credit facility is $230 million with the maturity date for any amount outstanding being November 2003. We have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due November 2004) in accordance with the terms of the credit agreement. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. We applied $60.0 million in proceeds from our February 2003 issuance of Senior Notes D to reduce the balance outstanding under this facility during 2003.

Variable interest rates charged under this facility generally bear interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent 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. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.5%.

The 364-Day Revolving Credit facility 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 quarter. As defined within 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, 2002.

Multi-Year Revolving Credit facility. In conjunction with the 364-Day Revolving Credit facility, we entered into a five-year revolving credit facility (the "Multi-Year Revolving Credit facility") that includes a sublimit capacity of $75 million for standby letters of credit. Currently, the stand-alone borrowing capacity under this credit facility is $270 million. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. The interest rates charged under this facility are determined in the same manner as that described under our 364-Day Revolving Credit facility. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.4%.

This facility contains various covenants similar to those of our 364-Day Revolving Credit facility (please refer to our discussion regarding restrictive covenants of the "*364-Day Revolving Credit facility*" within this "*General description of debt*" section). We were in compliance with these covenants at December 31, 2002.

Senior Notes A and B. These fixed-rate notes are an unsecured obligation of the Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness. Both notes are guaranteed by the MLP through an unsecured and unsubordinated guarantee and are non-recourse to the General Partner. These notes were issued under an indenture containing certain covenants and are subject to a make-whole redemption right. 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, 2002.

MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, we entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by MLP through an unsecured and unsubordinated guarantee. The indenture agreement for this loan contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable within 120 days if our credit ratings decline below a Baa3 rating by Moody's (currently Baa2) and below a BBB- rating by Standard and Poors (currently BBB). Under these circumstances, the trustee (as defined within the loan agreement) may, and if requested to do so by holders of at least 25% of the principal amount of the underlying bonds, shall accelerate the maturity of the MBFC Loan, whereby the principal and all accrued and unpaid interest would become immediately due and payable. If such an event occurred, we would have the option of (1) to redeem the MBFC Loan or (2) to provide an alternate credit agreement to support our obligation under the MBFC Loan. We would have 120 days to exercise these options upon receiving notice of the decline in our credit ratings.

The MBFC Loan agreement contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility and restrictions regarding mergers. We were in compliance with these covenants at December 31, 2002.

Seminole Notes. As a result of our acquisition of 78.4% of Seminole in July 2002, we are required to consolidate its debt with our other debt obligations. At December 31, 2002, Seminole had $45 million in fixed-rate senior unsecured notes, of which $15 million is due annually each December through December 2005. The Seminole Notes contain various covenants, such as minimum net worth requirements and those restricting Seminole's ability to borrow additional funds. Seminole was in compliance with these covenants at December 31, 2002.

New debt obligations issued during first quarter of 2003

January 2003 Senior Notes Offering. In January 2003, we issued $350 million in principal amount of 6.375% Senior Notes due 2013 ("Senior Notes C"), from which we received net proceeds before offering expenses of approximately $347.7 million. 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.

February 2003 Senior Notes Offering. In February 2003, we issued $500 million in principal amount of 6.875% Senior Notes due 2033 ("Senior Notes D"), from which we received net proceeds before offering expenses of approximately $489.8 million. 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.

Credit ratings

Our current investment grade credit ratings are Baa2 by Moody's Investor Service and BBB by Standard and Poors. Upon our acquisitions of the Mid-America and Seminole pipelines, which were financed by the $1.2 billion 364-Day Term Loan, both agencies maintained our ratings; however, each placed us on negative outlook pending the issuance of an appropriate amount of equity. The agencies have responded positively to our recent equity and debt offerings. 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 which independently judge our creditworthiness based on a variety of quantitative and qualitative factors.

Cash requirements for future growth

Acquisitions. We are committed to the long-term growth and viability of the Company. Our strategy involves expansion through business acquisitions and internal growth projects. In recent years, major oil and gas companies have sold non-strategic assets in the midstream energy industry in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestures. Management continues to analyze potential acquisitions, joint venture or similar transactions with businesses that operate in complementary markets and geographic regions. We believe that the Company is positioned to continue to grow through acquisitions that will expand its platform of assets and through internal growth projects. Our goal is to invest $500 million annually in such opportunities to the extent we believe such investments will be accretive to our Unitholders.

We expect that the funds needed to achieve this goal will be obtained through a combination of operating cash flows; public and private placement debt; and the issuance of partnership equity. Our $1.7 billion in business acquisitions and internal growth projects we completed during 2002 were initially funded with approximately $1.5 billion of debt. This will translate into increased debt service costs in the future. To the extent proceeds from future partnership equity offerings are used to reduce the principal amount of debt, our interest expense will be reduced. To the extent we refinance our existing debt with new debt, our interest expense will generally be affected by differences in interest rates charged on the existing debt versus the new debt and by any fees associated with the new debt.

Distributions. Another stated goal of management is to increase the distribution rate to our partners by at least 10% annually. At the end of 2002, the declared annual rate was $1.38 per Common Unit, which was 10.4% higher than the rate in effect at the end of 2001. An increase in our distribution rate will translate into additional cash payments to existing Unitholders. In addition, an increase in the number of Units eligible for cash distributions will result in higher payments. We issued 14.7 million new Common Units in January 2003 and expect to convert Shell's remaining 10.0 million Special Units to distribution-bearing Common Units in August 2003. Both of these transactions will have the effect of increasing cash distributions over those paid during 2002. On an annualized basis assuming a distribution rate of $1.38 per Common Unit, our distributions to partners would increase by $34.1 million as a result of these additional 24.7 million Common Units. We believe that all cash distributions will be paid out of operating cash flows over the long-term; however, from time to time, we may temporarily borrow under our debt agreements for the purpose of paying cash distributions until the full impact of our operations are realized.

Capital spending. At December 31, 2002, we had $7.8 million in estimated outstanding purchase commitments attributable to capital projects. Of this amount, $1.5 million is related to the construction of assets that will be recorded as property, plant and equipment and $6.3 million is associated with our share of capital projects of our unconsolidated affiliates which will be recorded as additional investments in unconsolidated affiliates.

During 2003, we expect capital spending on internal growth projects to approximate $110.2 million, of which $22.8 million is forecasted for various projects within our Pipelines segment; $38.6 million for the expansion of our Norco NGL fractionator and $40.0 million for the expansion of our Neptune gas processing facility. Our unconsolidated affiliates forecast a combined $63.1 million in capital expenditures during 2003, the majority of which relate to expansion projects on our Gulf of Mexico natural gas pipeline systems. Our share of these forecasted capital expenditures is estimated at $26.2 million.

At our formation, EPCO contributed various equipment leases to us for which they have retained the liability for the lease payments (the "retained leases"). These leases relate to an isomerization unit, a DIB tower, two cogeneration units and approximately 100 railcars. EPCO has assigned to us the purchase options associated with these leases. If we decide to exercise these purchase options (which are at fair market value), up to $26.0 million is expected to be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016.

As a result of new regulations imposing stricter air emissions requirements on petrochemical production and similar facilities in the Houston-Galveston area, we are required to redesign and modify certain components of our Mont Belvieu facility to comply with these new Clean Air Act requirements. Based upon these newly approved regulations, we estimate capital expenditures of $25 to $30 million (in the aggregate) will be required to modify our Mont Belvieu facilities. Through December 31, 2002, we spent $0.2 million related to this project. We forecast to spend between two and three million dollars for such modifications during 2003. The remaining amount is expected to be spent between 2004 and 2007.

Summary of material contractual obligations

The following table summarizes our material contractual obligations at December 31, 2002 (dollars in thousands, volumes as stated):

Contractual Obligations	Total	2003	2004 through 2005	2006 through 2007	After 2007
Scheduled principal payments to be made					
Under debt obligations	$ 2,245,000	$ 1,037,000	$ 704,000		$ 504,000
Potential payments under					
letter of credit agreements	$ 2,400		$ 2,400		
Payments due under operating leases	$ 17,793	$ 7,148	$ 5,840	$ 1,182	$ 3,623
Capital expenditure commitments	$ 7,797	$ 7,797			
Long-term purchase commitments:					
(Expressed in terms of minimum					
volumes under contract per period:)					
NGLs (MBbls)	60,848	15,986	22,752	11,310	10,800
Petrochemicals (MBbls)	82,096	25,428	42,144	14,524	
Natural gas (BBtus)	190,282	23,053	39,084	36,895	91,250

Our scheduled principal payments reflect consolidated amounts due under public and private placement debt obligations. Total principal amount outstanding under debt obligations as shown in the table above does not reflect the issuance of our $350 million Senior Notes C in January 2003 (due 2013) and $500 million Senior Notes D in February 2003 (due 2033) nor does it reflect the complete repayment of the 364-Day Term Loan in February 2003. Our potential payments under letter of credit agreements are associated with our purchase of hydrocarbon imports and the guarantee of our share of Evangeline's debt service reserve requirements. For additional information regarding our debt obligations, please see "*Our debt obligations*" on page 30.

We lease certain equipment and processing facilities under noncancelable and cancelable operating leases. The payments due under these leases (as shown above) represent our minimum future rental payments. The operating lease commitments shown above 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").

We routinely invest in capital projects of our own and in those of our unconsolidated affiliates. The amount shown above reflects the committed expenditures under these projects at December 31, 2002. Lastly, we have long-term purchase commitments for NGLs, petrochemicals and natural gas with several suppliers. In general, the purchase prices contained within these supply contracts approximate market prices at the time we take delivery of the volumes.

Recent accounting developments

We adopted SFAS No. 142, "*Goodwill and Other Intangible Assets*", on January 1, 2002. This standard establishes accounting standards for all goodwill and other intangible assets recognized in our consolidated balance sheet. In addition, we adopted SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*" on January 1, 2002. This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. For information regarding our goodwill, intangible assets and long-lived assets, please see the Notes to Consolidated Financial Statements.

We adopted SFAS No. 143, "*Accounting for Asset Retirement Obligations*," on January 1, 2003. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation ("ARO") and the associated asset retirement cost. An ARO exists when a company determines that it has a clearly defined legal obligation upon retirement of a long-lived asset or any component part thereof and that the legal obligation will lead to the future payment of funds to a third party upon retirement of the asset. In general, legal obligations underlying AROs result from enacted laws and regulations or from contractual provisions related to long-lived assets. AROs can also arise through the normal course of operating a long-lived fixed asset.

An ARO liability will be recorded on the balance sheet if a reasonable estimate of fair value of the obligation can be made. Our estimate of fair value for each ARO is primarily dependent upon a clearly defined plan of retirement (dates, methods, etc.) and costs associated with the retirement activity. If a reasonable estimate cannot be made (i.e., no current or required plans for retirement of the asset, etc.), footnote disclosure is required but the ARO is not recorded until a reasonable estimate can be made. Any earnings impact resulting from the recognition of an ARO upon adoption of SFAS No. 143 should be reflected as the cumulative effect of a change in accounting principle.

Upon adoption of SFAS No. 143, we reviewed our long-lived assets for ARO's by segment. We identified, but have not recognized, ARO liabilities in several operational areas. These include ARO liabilities related to easements over property not currently owned by us. Our rights to the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently plan to renew all such easement agreements and use these properties indefinitely. Therefore, the ARO liability is not estimable for such easements. If we decide not to renew these agreements, an ARO liability would be recorded at that time.

ARO liabilities related to statutory regulatory requirements for abandonment or retirement of certain currently operated facilities were also identified. 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 occurred.

Certain Gulf of Mexico natural gas pipelines, in which we have an equity interest, have identified ARO's relating to regulatory requirements. There is no current intention to abandon or retire these pipelines. If these pipelines were abandoned or retired, an ARO liability would then be disclosed.

In July 2002, the FASB issued SFAS No. 146, "*Accounting for Costs Associated with Exit or Disposal Activities*." This standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operations, plant closing, or other exit or disposal activity. Previous accounting guidance was provided by EITF Issue No. 94-3, "*Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)*." SFAS No. 146 replaces Issue 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. We adopted this statement on January 1, 2003 and determined that it had no material impact on our financial statements.

In November 2002, the FASB issued Interpretation No. 45, "*Guarantor's Accounting and Disclosure Requirements from Guarantees, Including Indirect Guarantees of Indebtedness of Others*". 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. The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in this interpretation are applicable for financial statements of interim or annual periods after December 15, 2002. See "*Our debt obligations*" on page 30 for a discussion of our Parent-Subsidiary guarantor relationships.

In December 2002, the FASB issued SFAS No. 148, "*Accounting for Stock-Based Compensation-Transition and Disclosure*," which 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 in both annual and interim financial statements. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. EPCO has stock-based employee compensation plans for which we have a funding commitment for certain employees. We do not believe that the adoption of this statement will have a 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. Examples of these estimates and assumptions include depreciation methods and estimated lives of property, plant and equipment, amortization methods and estimated lives of qualifying intangible assets, methods employed to measure the fair value of goodwill, revenue recognition policies and mark-to-market accounting procedures. The following describes the estimation risk in each of these significant financial statement items:

- *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 35 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. Additionally, if we determine that an asset's undepreciated cost may not be recoverable due to economic obsolescence, the business climate, legal or other factors, we would review the asset for impairment and record any necessary reduction in the asset's value as a charge against earnings. At December 31, 2002 and 2001, the net book value of our property, plant and equipment was $2.8 billion and $1.3 billion, respectively.

- *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 (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.

  At December 31, 2002, our significant intangible assets consisted of the following (along with unamortized balances of each group at that date):

  - the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999 ($183.2 million);
  - certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002 ($59.5 million); and
  - certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002 ($30.3 million).

The Shell natural gas processing agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term. The propylene fractionation and storage contracts acquired from Diamond-Koch are being amortized on a straight-line basis over the economic life of the assets to which they relate, which is currently estimated at 35 years. The Toca-Western natural gas processing contracts are being amortized on a straight-line basis over the expected 20-year remaining life of the natural gas supplies supporting these contracts. The Toca-Western NGL fractionation contracts are being amortized on a straight-line basis over the expected 20-year remaining life of the assets to which they relate.

If the underlying assumption(s) governing the amortization of an intangible asset were later determined to have significantly changed (either favorably or unfavorably), we then might need 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 then might need to reduce its carrying value and subsequent useful life. 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. During 2002, we did not recognize any impairment losses related to our intangible assets.

- *Goodwill.* At December 31, 2002, the recorded value of goodwill was $81.5 million. 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 on January 1, 2002, our goodwill amounts are no longer amortized. Instead, goodwill is tested at a reporting unit level annually, and 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.), the fair value of the reporting unit, including its related goodwill, is calculated and compared to its combined book value. Currently, all of our goodwill is 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, 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.

- *Revenue recognition.* 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. The revenues that we record are not materially based on estimates. We believe the assumptions underlying any revenue estimates that we might use will not prove to be significantly different from actual amounts due to the routine nature of these estimates and the stability of our operations. Of the contracts that we enter into with customers, the majority fall within five main categories as described below:

  - Tolling (or throughput) arrangements where we process or transport customer volumes for a cash fee (usually on a per gallon or other unit of measurement basis);
  - Product sales contracts where we sell products to customers at market-related prices for cash;
  - Storage agreements where we store volumes or reserve storage capacity for customers for a cash fee; and
  - Fee-based marketing services where we market volumes for customers for either a percentage of the final cash sales price or a cash fee per gallon handled.

A number of tolling arrangements are utilized in our Fractionation and Pipeline segments. Examples include NGL fractionation, isomerization and pipeline transportation agreements. Typically, we recognize revenue from tolling arrangements once contract services have been performed. At times, the tolling fees we or our affiliates charge for pipeline transportation services are regulated by such governmental agencies as the FERC. At certain of our NGL fractionation facilities, an in-kind tolling arrangement is utilized. An in-kind 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. Fractionation revenue is recognized and recorded on a monthly basis for transfers of "in-kind" 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.

Our Processing segment activities employ tolling and product sales contracts. If a customer pays us a cash tolling fee for our natural gas processing services, we record revenue to the extent that natural gas volumes have been processed and sent back to the producer. If the natural gas processing contract stipulates that we retain a percentage of the extracted NGLs as payment for our services, revenue is recognized and recorded when the extracted NGLs are delivered out of our inventory and sold to customers on sales contracts. Our NGL marketing activities within this segment also use product sales contracts to sell and deliver out of inventory the NGLs transferred to it as a result of the Fractionation segment's in-kind 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. In addition to the Processing segment, product sales contracts are utilized in the Fractionation segment to record revenues from the sale of petrochemical products and in the Pipelines segment to record revenues from the sale of natural gas. Pricing terms in our product sales contracts are based upon market-related prices for such products and can include pricing differentials due to factors such differing delivery locations.

- *Fair value accounting for commodity financial instruments.* Our earnings are also affected by use of the mark-to-market method of accounting required under GAAP 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. As of December 31, 2002, none of our commodity financial instruments qualify for hedge accounting treatment and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. 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 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.

  For the year ended December 31, 2002, we recognized losses from our commodity hedging activities of $51.3 million. Of this loss, $5.6 million is attributable to the negative change in market value of the commodity hedging portfolio since December 31, 2001 using the mark-to-market method of accounting for our financial instruments. The fair value of our commodity financial instrument portfolio at December 31, 2002 was a payable of $26 thousand, based upon quoted market prices. At that date, we had a limited number of open positions that extend through December 2003. 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, see the Processing segment discussion under "*Our results of operations*" on page 23.

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

Related party transactions

Relationship with EPCO and Its Affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates. EPCO is majority-owned and controlled by Dan L. Duncan, Chairman of the Board and a director of the General Partner. In addition, three other members of the Board of Directors (O.S. Andras, Randa D. Williams and Richard H. Bachmann) and the remaining executive and other officers (see Item 10 for a listing of these individuals) of the General Partner are employees of EPCO. The principal business activity of our General Partner is to act as our managing partner. Collectively, EPCO and its affiliates (which includes the 1998 Trust, 2000 Trust and Dan L. Duncan) owned 61.4% of our limited partnership interests and 70.0% of our General Partner at December 31, 2002.

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the EPCO Agreement. We reimburse EPCO for the costs of its employees who perform operating functions for us. In addition, we reimburse EPCO for the costs of certain of employees who manage our business and affairs.

EPCO is also the operator of certain facilities we own or have an equity interest in. We have also entered into an agreement with EPCO to provide trucking services to us for the loading and transportation of products. Lastly, in the normal course of business, we buy from and sell NGL products to EPCO's Canadian affiliate.

During 2002, our related party revenues from EPCO were $3.6 million and our related party expenses with EPCO were $127.4 million. For additional information regarding our relationship with EPCO, see footnote 14, titled "Related Party Transactions" on page 76.

Relationship with Shell

We have an extensive and ongoing commercial relationship with Shell as a partner, customer and vendor. Shell currently owns approximately 20.5% of our limited partnership interests and 30.0% of our General Partner. Currently, three members of the Board of Directors of the General Partner (J.A. Berget, J.R. Eagan and A.Y. Noojin, III) are employees of Shell.

Shell and its affiliates are the Company's single largest customer. During 2002, they accounted for 7.8% of our consolidated revenues. Our revenues from Shell reflect the sale of NGL and petrochemical products to them and the fees we charge them 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 (see the "*Processing*" segment discussion) and the purchase of NGL products from them. During 2002, our related party revenues from Shell were $282.8 million and our related party expenses with Shell were $531.7 million.

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 $528.8 million (this purchase price includes both the $166 million in cash we paid to Shell and the value of the three issues of Special Units granted to Shell in connection with this acquisition);
- the purchase of the Lou-Tex Propylene Pipeline System 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 the Gulf of Mexico natural gas pipelines we acquired from El Paso in 2001. 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 33.3% ownership interest in BEF, which owns a facility currently producing MTBE. At December 31, 2002, the carrying value of our investment in BEF was $54.9 million. Our equity earnings from BEF (which are recorded under our Octane Enhancement segment) were $8.5 million, $5.7 million and $10.4 million during 2002, 2001 and 2000, respectively. 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. Although these detections have been limited and the great majority have been well below levels of public health concern, there have been calls for the phase-out of MTBE in motor gasoline in various federal and state governmental agencies and advisory bodies. BEF has not been named in any MTBE legal action to date.

During 2000, the city of Santa Monica brought suit against seven major oil companies and eleven other manufacturers, suppliers, refiners and pipeline operators alleging the defendants had tainted much of the city's drinking water supply with MTBE. In mid-July 2002, the city settled with two of the major oil companies. Under the terms of this settlement, the two defendants agreed to pay to design, build and operate a facility to treat the city's water (at a cost of approximately $200 million) and to pay $30 million in other damages. The court agencies involved in this case are reviewing this settlement. The city is still pursuing legal action against the remaining defendants.

In April 2002, a jury in California found three energy companies liable for polluting Lake Tahoe's drinking water with MTBE. While this decision sets no legal precedent, this was the first time that a jury has defined gasoline containing MTBE to be a "defective product". In August 2002, two of the defendants were ordered to pay $28 million to a Lake Tahoe-area utility district. The third defendant settled out of court for $4 million in July 2002.

In light of these developments, we and the other two owners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently evaluating a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical component of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and the level of production desired by the partnership.

Two-for-one split of Limited Partner Units

On February 27, 2002, we announced that the Board of Directors of the General Partner had approved a two-for-one split for each class of our Units. The partnership Unit split was accomplished by distributing one additional partnership Unit for each partnership Unit outstanding to holders of record on April 30, 2002. The Units were distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document relate to the post-split Units, except if indicated otherwise.

Conversion of EPCO Subordinated Units and Shell Special Units to Common Units

As a result of the Company satisfying certain financial tests, 10,704,936 (or 25%) of EPCO's Subordinated Units converted to Common Units on May 1, 2002. If the financial criteria continue to be satisfied through the first quarter of 2003, an additional 25% of the Subordinated Units will undergo an early conversion on a one-for-one basis to Common Units on May 1, 2003. The remaining 50% of Subordinated Units will convert on August 1, 2003 if the balance of the conversion requirements are met. Subordinated Units have limited voting rights until converted to Common Units. The conversion(s) will have no impact upon our distributions or earnings per unit since the Subordinated Units are already distribution-bearing and included in both the basic and fully diluted calculations.

In accordance with existing agreements with Shell, 19.0 million of Shell's non-distribution bearing Special Units converted to distribution-bearing Common Units on August 1, 2002. The remaining 10.0 million Special Units will convert to Common Units on a one-for-one basis in August 2003. These conversions have a dilutive impact on basic earnings per Unit since they increase the number of Common Units used in the computation. As a result of the August 2002 conversion of the Shell Special Units to an equal number of Common Units, our basic earnings per Unit for 2002 were reduced by $0.03. Special Units are excluded from the computation of basic earnings per Unit because, under the terms of the Special Units, they do not share in income nor are they entitled to cash distributions until they are converted to Common Units.

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, see the Notes to our Consolidated Financial Statements.

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 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, 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 ommodity 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 (values in thousands of dollars):

Scenario	Resulting classification	At 12/31/01	At 12/31/02	At 03/03/03
FV assuming no change in quoted market prices	*Asset (Liability)*	$ 6,786	$ (26)	$ 84
FV assuming 10% increase in quoted market prices	*Asset (Liability)*	$ 844	$ (26)	$ 380
IE assuming 10% increase in quoted market prices	*Income (Loss)*	$ (5,942)	$ -	$ 296
FV assuming 10% decrease in quoted market prices	*Asset (Liability)*	$ 12,599	$ (26)	$ (211)
IE assuming 10% decrease in quoted market prices	*Income (Loss)*	$ 5,813	$ -	$ (295)

At December 31, 2001, the net fair value of our commodity financial instruments portfolio was a $6.8 million asset, almost all of which was based upon quoted market prices. At December 31, 2002, the net fair value of this portfolio was a payable of $26,000, based entirely upon quoted market prices. Due to commodity hedging losses we incurred during the first quarter of 2002, we exited most of our positions (see our Processing segment discussion under "*Our results of operations*"). At December 31, 2002, we had a limited number of commodity financial instruments outstanding. The fair value of the portfolio at March 3, 2003 was a $84,00 asset and was again comprised of a limited number of positions.

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.

Product purchase commitments. We have long-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.

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. 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. We believe that it is prudent to maintain an appropriate balance of variable-rate and fixed-rate debt.

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

Scenario	Resulting classification	At 12/31/01	At 12/31/02
FV assuming no change in quoted market prices	*Asset (Liability)*	$ 3,531	$ 1,634
FV assuming 10% increase in quoted market prices	*Asset (Liability)*	$ 3,345	$ 1,634
IE assuming 10% increase in quoted market prices	*Income (Loss)*	$ (186)	$ -
FV assuming 10% decrease in quoted market prices	*Asset (Liability)*	$ 3,717	$ 1,634
IE assuming 10% decrease in quoted market prices	*Income (Loss)*	$ 186	$ -

At December 31, 2002 and 2001, we had one interest rate swap outstanding having a notional amount of $54 million that extended through March 2010. Under the terms of the swap, the counterparty had the right to terminate the swap on March 1, 2003. The fair value of this swap was a $3.5 million asset at December 31, 2001. The fair value of this swap at December 31, 2002 was $1.6 million. The change in fair value of this swap during 2002 is primarily due to settlements. A change in interest rates at December 31, 2002 would have negligible effect on the fair value of this swap. The counterparty elected to terminate this swap as of March 1, 2003 and we received $1.6 million associated with the final settlement of this swap on that date.

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.

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 are 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 by early February 2003 in connection with our issuance of Senior Notes C and D (see "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Our liquidity and capital resource—Our debt obligations*"). The settlement of the treasury locks resulted in our receipt of $5.4 million of cash.

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 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 will be 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, see footnote 18 titled "*Financial Instruments*" in the Notes to Consolidated Financial Statements on page 85.

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, 2002 and 2001, 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, 2002. 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, 2002 and 2001, and the results of its consolidated operations and its consolidated cash flows for each of the three years in the period ended December 31, 2002 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 7, 2003

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

	December 31,			
ASSETS		**2002**		**2001**
Current Assets				
Cash and cash equivalents (includes restricted cash of $8,751 at December 31, 2002 and $5,752 at December 31, 2001)	$	22,568	$	137,823
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $21,196 at December 31, 2002 and $20,642 at December 31, 2001		399,187		256,024
Accounts receivable – affiliates		228		4,375
Inventories		167,369		62,942
Prepaid and other current assets		48,216		51,110
Total current assets		637,568		512,274
Property, Plant and Equipment, Net		2,810,839		1,306,790
Investments in and Advances to Unconsolidated Affiliates		396,993		398,201
Intangible assets, net of accumulated amortization of $25,546 at December 31, 2002 and $13,084 at December 31, 2001		277,661		202,226
Goodwill		81,547		
Deferred Tax Asset		15,846		
Other Assets		9,818		5,201
Total	$	4,230,272	$	2,424,692
LIABILITIES AND PARTNERS' EQUITY				
Current Liabilities				
Current maturities of long-term debt	$	15,000		
Accounts payable – trade		67,283	$	54,269
Accounts payable – affiliates		40,772		29,885
Accrued gas payables		489,562		227,035
Accrued expenses		35,760		22,460
Accrued interest		30,338		24,302
Other current liabilities		42,641		44,764
Total current liabilities		721,356		402,715
Long-Term Debt		2,231,463		855,278
Other Long-Term Liabilities		7,666		8,061
Minority Interest		68,883		11,716
Commitments and Contingencies				
Partners' Equity				
Common Units (141,694,766 Units outstanding at December 31, 2002 and 102,721,830 at December 31, 2001)		949,835		651,872
Subordinated Units (32,114,804 Units outstanding at December 31, 2002 and 42,819,740 at December 31, 2001)		116,288		193,107
Special Units (10,000,000 Units outstanding at December 31, 2002 and 29,000,000 December 31, 2001)		143,926		296,634
Treasury Units acquired by Trust, at cost (859,200 Common Units outstanding at December 31, 2002 and 327,200 at December 31, 2001)		(17,808)		(6,222)
General Partner		12,223		11,531
Accumulated Other Comprehensive Loss		(3,560)		
Total Partners' Equity		1,200,904		1,146,922
Total	$	4,230,272	$	2,424,692

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,		
	2002	**2001**	**2000**
REVENUES			
Revenues from consolidated operations			
Third parties	$ 3,102,066	$ 2,641,913	$ 2,689,541
Related parties	482,717	512,456	359,479
Total revenues	3,584,783	3,154,369	3,049,020
COST AND EXPENSES			
Operating costs and expenses			
Third parties	2,686,982	2,052,309	1,953,341
Related parties	695,579	809,434	847,719
Selling, general and administrative			
Third parties	18,686	10,347	12,665
Related parties	24,204	19,949	15,680
Total costs and expenses	3,425,451	2,892,039	2,829,405
EQUITY IN INCOME OF UNCONSOLIDATED AFFILIATES	35,253	25,358	24,119
OPERATING INCOME	194,585	287,688	243,734
OTHER INCOME (EXPENSE)			
Interest expense	(101,580)	(52,456)	(33,329)
Interest income from related parties	139	31	1,787
Dividend income from unconsolidated affiliates	4,737	3,462	7,091
Interest income - other	2,313	7,029	3,748
Other, net	(113)	(1,104)	(272)
Other income (expense)	(94,504)	(43,038)	(20,975)
INCOME BEFORE PROVISION FOR INCOME TAXES AND MINORITY INTEREST	100,081	244,650	222,759
PROVISION FOR INCOME TAXES	(1,634)		
INCOME BEFORE MINORITY INTEREST	98,447	244,650	222,759
MINORITY INTEREST	(2,947)	(2,472)	(2,253)
NET INCOME	95,500	242,178	220,506
Cumulative transition adjustment related to financial instruments recorded upon adoption of SFAS No. 133 (see Note 1)		(42,190)	
Reclassification of cumulative transition adjustment to earnings		42,190	
Change in fair value of financial instruments recorded as cash flow hedges	(3,560)		
COMPREHENSIVE INCOME	$ 91,940	$ 242,178	$ 220,506
ALLOCATION OF NET INCOME TO:			
Limited partners	$ 84,837	$ 236,570	$ 217,909
General partner	$ 10,663	$ 5,608	$ 2,597
BASIC EARNINGS PER UNIT			
Income before minority interest	$ 0.56	$ 1.71	$ 1.64
Net income per Common and Subordinated unit	$ 0.55	$ 1.70	$ 1.62
DILUTED EARNINGS PER UNIT			
Income before minority interest	$ 0.50	$ 1.40	$ 1.34
Net income per Common, Subordinated and Special unit	$ 0.48	$ 1.39	$ 1.32

See Notes to Consolidated Financial Statements

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

	For Year Ended December 31,		
	2002	**2001**	**2000**
OPERATING ACTIVITIES			
Net income	$ 95,500	$ 242,178	$ 220,506
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:			
Depreciation and amortization in operating costs and expenses	86,029	48,775	35,621
Depreciation in selling, general and administrative costs	77	2,341	1,689
Amortization in interest expense	8,819	787	3,735
Equity in income of unconsolidated affiliates	(35,253)	(25,358)	(24,119)
Distributions received from unconsolidated affiliates	57,662	45,054	37,267
Leases paid by EPCO	9,033	10,309	10,537
Minority interest	2,947	2,472	2,253
Loss (gain) on sale of assets	(1)	(390)	2,270
Deferred income tax expense	2,080		
Changes in fair market value of financial instruments (see Note 18)	10,213	(5,697)	
Net effect of changes in operating accounts	92,655	(37,143)	71,111
Operating activities cash flows	329,761	283,328	360,870
INVESTING ACTIVITIES			
Capital expenditures	(72,135)	(149,896)	(243,913)
Proceeds from sale of assets	165	568	92
Business acquisitions, net of cash received	(1,620,727)	(225,665)	
Acquisition of intangible asset	(2,000)		
Collection of note receivable from unconsolidated affiliate			6,519
Investments in and advances to unconsolidated affiliates	(13,651)	(116,220)	(31,496)
Investing activities cash flows	(1,708,348)	(491,213)	(268,798)
FINANCING ACTIVITIES			
Borrowings under debt agreements	1,968,000	449,717	598,818
Repayments of debt	(637,000)		(490,000)
Debt issuance costs	(19,329)	(3,125)	(4,043)
Distributions paid to partners	(214,869)	(164,308)	(139,577)
Distributions paid to minority interest by Operating Partnership	(3,324)	(1,687)	(1,429)
Contributions from minority interest	1,976	105	108
Common Units repurchased and retired			(770)
Proceeds from issuance of Common Units	180,666		
Treasury Units purchased	(12,788)	(18,003)	
Treasury Units reissued		22,600	
Increase in restricted cash	(2,999)	(5,752)	
Financing activities cash flows	1,260,333	279,547	(36,893)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(118,254)	71,662	55,179
CASH AND CASH EQUIVALENTS, JANUARY 1	132,071	60,409	5,230
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 13,817	$ 132,071	$ 60,409

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	Special Units	Treasury Units	General Partner	Accum. OCI	Total
Balance, December 31, 1999	$ 439,196	$ 136,618	$ 210,436	$ (4,727)	$ 7,942		$ 789,465
Net income	148,656	69,253			2,597		220,506
Leases paid by EPCO	7,117	3,315			105		10,537
Special Units issued to Shell under contingency agreement			55,241		557		55,798
Conversion of 2.0 million Shell Special Units to Common Units	14,513		(14,513)				-
Common Units repurchased and retired	(687)	(43)	(32)		(8)		(770)
Cash distributions to partners	(93,899)	(43,890)			(1,788)		(139,577)
Balance, December 31, 2000	514,896	165,253	251,132	(4,727)	9,405		935,959
Net income	163,795	72,775			5,608		242,178
Leases paid by EPCO	7,078	3,128			103		10,309
Special Units issued to Shell under contingency agreement			117,066		1,183		118,249
Conversion of 10.0 million Shell Special Units to Common Units	72,554		(72,554)				-
Cash distributions to partners	(109,969)	(49,510)			(4,829)		(164,308)
Treasury Units purchased				(18,003)			(18,003)
Treasury Units reissued				16,508			16,508
Gain on reissuance of Treasury Units by consolidated Trust	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
Leases paid by EPCO	6,872	2,071			90		9,033
Conversion of 19.0 million Shell Special Units to Common Units	152,708		(152,708)				-
Conversion of 10.7 million EPCO Subord. Units to Common Units	44,265	(44,265)					-
Cash distributions to partners	(153,449)	(49,564)			(11,856)		(214,869)
Proceeds from issuance of Common Units in October 2002	178,859				1,807		180,666
Treasury Units purchased				(12,788)			(12,788)
Treasury Units reissued to satisfy EPCO Unit option plans	(928)	(262)		1,202	(12)		-
Change in fair value of financial instruments recorded as cash flow hedges (see Note 18)						(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.
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 New York Stock Exchange under symbol "EPD". Unless the context requires otherwise, references to "we","us","our" or the "Company" within these notes are intended to mean Enterprise Products Partners L.P. and subsidiaries. We (including our operating subsidiary, Enterprise Products Operating L.P. (the "Operating Partnership")) were formed in April 1998 to own and operate the natural gas liquids ("NGL") business of Enterprise Products Company ("EPCO"). We conduct substantially all of our business through the Operating Partnership, in which we own a 98.9899% limited partner interest. Enterprise Products GP, LLC (the "General Partner") owns 1.0101% of the Operating Partnership and 1% of the Company and serves as the general partner of both entities. We and the General Partner are affiliates of EPCO.

Prior to their consolidation, EPCO and its affiliate companies were controlled by members of a single family, who collectively owned at least 90% of each of the entities for all periods prior to the formation of the Company. As of April 30, 1998, the owners of all the affiliated companies exchanged their ownership interests for shares of EPCO. Accordingly, each of the affiliated companies became a wholly-owned subsidiary of EPCO or was merged into EPCO as of April 30, 1998. In accordance with generally accepted accounting principles, the consolidation of the affiliated companies with EPCO was accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests.

Under terms of a contract entered into on May 8, 1998 between EPCO and our Operating Partnership, EPCO contributed all of its NGL assets through the Company and the General Partner to the Operating Partnership and the Operating Partnership assumed certain of EPCO's debt. As a result, we became the successor to the NGL operations of EPCO. Effective July 27, 1998, we filed a registration statement pursuant to an initial public offering of 24,000,000 Common Units at $11 per unit. We received approximately $243.3 million net of underwriting commissions and offering costs.

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 the Company 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 other than a temporary decline. The Company considers events affecting its equity method investments such as if they had continuing operating losses or significant and long-term changes in their industry conditions as examples of indicators of potential impairment. 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 for 2002, 2001 and 2000.

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 results of consolidated operations.

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.

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. Specifically, basic earnings per Unit is calculated by dividing the amount of income allocated to limited partners by the weighted-average number of Common and Subordinated Units outstanding during the period. Diluted earnings per Unit is based on the amount of income allocated to limited partners and the weighted-average number of Common, Subordinated and Special Units outstanding during the period. The Special Units are excluded from the computation of basic earnings per Unit because, under the terms of the Special Units, they do not share in income nor are they entitled to cash distributions until they are converted to Common Units. Treasury Units are not considered to be outstanding; therefore, they are excluded from the computation of both basic and diluted earnings per Unit. 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, 2002 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated \$1.7 million, \$1.3 million and \$1.3 million for the years ended December 31, 2002, 2001 and 2000, 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 investments in Promix, Dixie, Neptune, La Porte and Nemo. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. 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.

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 the Company. 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. 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 (as amended and interpreted) 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.

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. We have not recognized any impairment losses for any of the periods presented.

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 adopted SFAS No. 144 on January 1, 2002, and there have been no events or circumstances indicating that the carrying value of any of our assets may not be recoverable.

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

Additions and improvements to and major renewals of existing assets are capitalized and depreciated using the straight-line method over the estimated useful life of the new equipment or modifications. These expenditures result in a long-term benefit to the Company. We generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending (on existing and new assets) as expansion capital expenditures.

PROVISION FOR INCOME TAXES is only applicable to the tax obligation of our Seminole pipeline business, which is a corporation and the only entity subject to income taxes in the consolidated group. The income tax provision relates solely to Seminole's earnings before income taxes for the five month period ended December 31, 2002. Deferred income tax assets and liabilities for Seminole are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes (see Note 12).

In and of itself, 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, 2002 and 2001, cash and cash equivalents includes $8.8 million and $5.8 million of restricted cash related to these requirements, respectively.

REVENUE is recognized by our five reportable business segments 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. For additional information regarding our revenue recognition process, please see Note 2.

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 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 $21.2 million and $20.6 million at December 31, 2002 and 2001, respectively.

UNIT OPTION PLAN ACCOUNTING for reimbursement to EPCO under its 1998 Plan is accounted for by applying APB Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for equity-based awards granted to EPCO's employees whereby no compensation expense is recorded related to the options granted when the exercise price equals the market price of the underlying equity issue on the date of grant. See Note 15 for the pro forma effect on our net income and earnings per unit, as if compensation expense had been determined based on the Black-Scholes option pricing model value at the grant date for Unit option awards consistent with the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." No compensation expense was recorded during the years ended December 31, 2002, 2001 and 2000, since the options were granted at exercise prices equal to the market prices at the date of grant.

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. REVENUE RECOGNITION

The following summarizes our revenue recognition process by business segment:

Pipelines segment revenues. In our Pipelines segment, 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 Federal Energy Regulatory Commission ("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.

Fractionation segment revenues. In our Fractionation segment, we enter into NGL fractionation, isomerization and propylene fractionation tolling arrangements, NGL fractionation in-kind 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, an in-kind tolling arrangement is utilized. An in-kind 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. Fractionation revenue is recognized and recorded on a monthly basis for transfers of “in-kind” 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.

Processing segment revenues. As part of our Processing business, we have entered into a significant 20-year natural gas processing agreement with Shell (the "Shell Processing Agreement"), whereby we have the right to process Shell's current and future natural gas production (including deepwater developments) from the Gulf of Mexico within the state and federal waters off Texas, Louisiana, Mississippi, Alabama and Florida. In addition to the Shell Processing Agreement, we have contracts to process natural gas for other customers.

Under these natural gas processing contracts, the fee for our natural gas processing services is based upon contractual terms with Shell or other third parties and may be specified as either a cash fee or the retention of a percentage of the NGLs extracted from the natural gas stream. 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 Shell or other third parties (i.e., delivery has taken place).

If the natural gas processing contract stipulates that we retain a percentage of the extracted NGLs as payment for our services, revenue is recognized and recorded when the extracted NGLs are delivered out of our inventory and sold to customers on sales contracts. Our NGL marketing activities within this segment also use product sales contracts to sell and deliver out of inventory the NGLs transferred to it as a result of the Fractionation segment’s in-kind 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 differing delivery locations.

Octane Enhancement segment revenues. The Octane Enhancement segment consists of our equity 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. Gross operating margin for this segment consists of our equity earnings from BEF, which in turn is dependent upon is BEF’s general revenue recognition policy. 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.

Other segment revenues. Revenues shown for our Other segment are primarily derived from fee-based marketing services. 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.

Use of estimates in our revenue recognition process. The revenues that we record are not materially based on estimates. We believe the assumptions underlying any revenue estimates that we might use will not prove to be significantly different from actual amounts due to the routine nature of these estimates.

3. RECENTLY ISSUED ACCOUNTING STANDARDS

We adopted SFAS No. 142, "Goodwill and Other Intangible Assets", on January 1, 2002. This standard establishes accounting standards for all goodwill and other intangible assets recognized in our consolidated balance sheet. In addition, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" on January 1, 2002. This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. For information regarding our goodwill and intangible assets see Note 8. For information regarding our accounting policy for long-lived assets, please see Note 1.

We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," on January 1, 2003. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation ("ARO") and the associated asset retirement cost. An ARO exists when a company determines that it has a clearly defined legal obligation upon retirement of a long-lived asset or any component part thereof and that the legal obligation will lead to the future payment of funds to a third party upon retirement of the asset. In general, legal obligations underlying AROs result from enacted laws and regulations or from contractual provisions related to long-lived assets. AROs can also arise through the normal course of operating a long-lived fixed asset.

An ARO liability will be recorded on the balance sheet if a reasonable estimate of fair value of the obligation can be made. Our estimate of fair value for each ARO is primarily dependent upon a clearly defined plan of retirement (dates, methods, etc.) and costs associated with the retirement activity. If a reasonable estimate cannot be made (i.e., no current or required plans for retirement of the asset, etc.), footnote disclosure is required but the ARO is not recorded until a reasonable estimate can be made. Any earnings impact resulting from the recognition of an ARO upon adoption of SFAS No. 143 should be reflected as the cumulative effect of a change in accounting principle.

Upon adoption of SFAS No. 143, we reviewed our long-lived assets for ARO's by segment.
We identified, but have not recognized, ARO liabilities in several operational areas. These include ARO liabilities related to easements over property not currently owned by us. Our rights to the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently plan to renew all such easement agreements and use these properties indefinitely. Therefore, the ARO liability is not estimable for such easements. If we decide not to renew these agreements, an ARO liability would be recorded at that time.

ARO liabilities related to statutory regulatory requirements for abandonment or retirement of certain currently operated facilities were also identified. 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 occurred.

Certain Gulf of Mexico natural gas pipelines, in which we have an equity interest, have identified ARO's relating to regulatory requirements. There is no current intention to abandon or retire these pipelines. If these pipelines were abandoned or retired, an ARO liability would then be disclosed.

In July 2002, the FASB issued SFAS No. 146, "*Accounting for Costs Associated with Exit or Disposal Activities*." This standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operations, plant closing, or other exit or disposal activity. Previous accounting guidance was provided by EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 replaces Issue 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. We adopted this statement on January 1, 2003 and determined that it had no material impact on our financial statements.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements from Guarantees, Including Indirect Guarantees of Indebtedness of Others". 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. The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements in this interpretation are applicable for financial statements of interim or annual periods after December 15, 2002. See Note 9 for the disclosure of Parent-Subsidiary guarantor relationships.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure," which 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 in both annual and interim financial statements. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. EPCO has stock-based employee compensation plans for which we have a funding commitment for certain employees, see Note 15. We do not believe that the adoption of this statement will have a material effect on our financial statements.

4. BUSINESS ACQUISITIONS

Acquisition of Mid-America and Seminole in July 2002

On July 31, 2002, we acquired equity interests in affiliates of Williams, which in turn, own controlling interests in Mid-America Pipeline Company, LLC ("Mid-America," formerly Mid-America Pipeline Company) and Seminole Pipeline Company ("Seminole"). The purchase price of the acquisitions was approximately $1.2 billion. The acquisition of Mid-America and Seminole significantly enhances our existing asset base by:

- accessing NGL-rich natural gas production in major North American natural gas producing regions;
- expanding our integrated natural gas and NGL network;
- providing access to new end markets for NGL products; and
- increasing our gross margins from fee-based businesses.

In addition to our current strategic position in the Gulf of Mexico, we now have access to major supply basins throughout North America, including the Rocky Mountain Overthrust, the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada's Western Sedimentary basin. The combination of these assets with our existing assets also creates a significant link between Mont Belvieu, Texas and Conway, Kansas, the two largest NGL hubs in the United States. They also provide additional access to new end markets for NGL products.

The acquisitions include a 98% ownership interest in Mapletree, LLC, which is the sole owner of Mid-America and certain propane terminals and storage facilities. Mid-America owns a regulated 7,226-mile major NGL pipeline system (the "Mid-America Pipeline System") consisting of three NGL pipelines: the 2,548-mile Rocky Mountain pipeline, the 2,740-mile Conway North pipeline, and the 1,938-mile Conway South pipeline. The Rocky Mountain system transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. The Conway North segment links the large NGL hub at Conway, Kansas to refineries and propane markets in the upper Midwest. In addition, the Conway North segment has access to, through third-party pipeline connections, NGL supplies from Canada's Western Sedimentary basin.

The Conway South system connects the Conway hub with Kansas refineries and transports mixed NGLs from Conway, Kansas to the Hobbs hub (with interconnections to the Seminole Pipeline System at the Hobbs hub).

We also acquired a 98% ownership interest in E-Oaktree, LLC, owner of an 80% equity interest in Seminole. Seminole owns a regulated 1,281-mile pipeline (the "Seminole Pipeline System") that transports mixed NGLs and NGL products from the Hobbs hub on the Texas-New Mexico border and the Permian Basin area to Mont Belvieu, Texas. The primary source of throughput for the Seminole system are those volumes originating from the Mid-America system.

The initial funding for these acquisitions was accomplished by entering into a $1.2 billion 364-day credit facility (the "364-Day Term Loan"; see Note 9 for a description of this debt). This temporary credit facility was extinguished in February 2003 when we completed our plans for the permanent financing of these acquisitions (see our discussion of subsequent events in Note 21). These acquisitions did not require any material governmental approvals.

Acquisition of Diamond-Koch propylene fractionation business in February 2002

In February 2002, we purchased various propylene fractionation assets and certain inventories of refinery grade propylene, propane, and polymer grade propylene from Diamond-Koch. These include a 66.7% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas (the "Splitter III" facility), a 50% interest in an entity which owns a polymer grade propylene export terminal located on the Houston Ship Channel in La Porte, Texas, and varying interests in several supporting distribution pipelines and related equipment. Splitter III has the capacity to produce approximately 41 MBPD of polymer grade propylene. These assets are part of our Mont Belvieu propylene fractionation operations, which is part of the Fractionation segment. The purchase price of $239.0 million was funded by a drawdown on our Multi-Year and 364-Day Revolving Credit facilities.

Acquisition of Diamond-Koch storage business in January 2002

In January 2002, we purchased various hydrocarbon storage assets from Diamond-Koch. The storage facility consists of 25 operational salt dome storage caverns with a useable capacity of 64 million barrels, local distribution pipelines and related equipment. The facilities provide storage services for mixed natural gas liquids, ethane, propane, butanes, natural gasoline and olefins (such as ethylene), polymer grade propylene, chemical grade propylene and refinery grade propylene. The facilities are located in Mont Belvieu, Texas and serve the largest petrochemical and refinery complex in the United States. These assets are part of our Mont Belvieu storage operations, which is part of the Pipelines segment. The purchase price of $129.6 million was funded by utilizing cash on hand.

Other minor acquisitions completed during 2002

We completed the purchase of an additional interest in our Mont Belvieu NGL fractionator from ChevronTexaco, the acquisition of a gas processing plant and NGL fractionator in Louisiana from Western Resources and certain NGL terminal assets from CornerStone during 2002. Due to the immaterial nature of each of these acquisitions, our discussion of each is limited to the following:

Acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator. Effective June 2002,, we finalized the acquisition of a 12.5% undivided ownership interest in our Mont Belvieu, Texas NGL fractionator from an affiliate of ChevronTexaco. The purchase price of approximately $8.1 million was paid in May 2002. As a result of this transaction, our ownership interest in the Mont Belvieu NGL fractionator increased to 75.0% from 62.5%.

Acquisition of gas processing and NGL fractionator assets from Western Gas Resources, Inc. Effective June 2002, we acquired a 160 MMcf/d natural gas processing plant, a 14.2 MBPD NGL fractionator and supporting assets (including contracts) from Western Gas Resources, Inc. for approximately $32.6 million. The "Toca-Western" facilities are located in St. Bernard Parish, Louisiana near our existing Toca natural gas processing plant.

Acquisition of NGL terminals from CornerStone. In November 2002, we purchased four NGL terminals and existing propane inventories from an affiliate of CornerStone for approximately $11.5 million. The terminals are located in Bakersfield and Rocklin, California; Reno, Nevada and Albertville, Alabama. In addition, we acquired storage facilities related to these terminals with a capacity of 0.1 million barrels. These terminals will support our NGL marketing activities and fee-based marketing services.

Acadian Gas post-closing adjustments completed in April 2002

In April 2002, we finalized the post-closing purchase price adjustment associated with our April 2001 acquisition of Acadian Gas. Acadian Gas was acquired from an affiliate of Shell and is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. As a result, we paid Shell $18.0 million for various working capital items, the majority of which were related to natural gas inventories.

Allocation of amounts paid during 2002

The acquisitions and post-closing adjustments described previously were accounted for under the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

	D-K Storage	D-K Propylene Fractionation	Mid-America and Seminole	Other	Total
Accounts and Notes receivable			$ 11,777	$ (120)	11,657
Accounts receivable - affiliates			7,799		7,799
Inventories		$ 4,994	10,776	4,403	20,173
Prepaids and other current assets	$ 890	3,148	9,204	416	13,658
Property, plant and equipment	120,571	96,772	1,265,264	24,636	1,507,243
Investments in unconsolidated affiliates		7,550			7,550
Intangible assets	8,127	53,000		31,229	92,356
Goodwill		73,691			73,691
Deferred tax asset			17,307		17,307
Other assets			2,699		2,699
Accounts payable - affiliates			(7,799)		(7,799)
Accrued expenses			(5,529)		(5,529)
Accrued interest			(667)		(667)
Other current liabilities		(107)	(12,226)	8,581	(3,752)
Long-term debt			(60,000)		(60,000)
Other long-term liabilities			(90)		(90)
Minority interest			(55,569)		(55,569)
Total purchase price	$ 129,588	$ 239,048	$ 1,182,946	$ 69,145	$ 1,620,727

The fair value estimates for both Diamond-Koch transactions; Mid-America and Seminole; the Toca-Western and CornerStone acquisitions were developed by independent appraisers using recognized business valuation techniques. The Mid-America, Seminole and CornerStone allocations are preliminary pending completion of a final review of these businesses which is expected to be completed during the first quarter of 2003. The purchase price allocations related to the Acadian Gas post-closing adjustment and the acquisition of ChevronTexaco's interest in our Mont Belvieu NGL fractionator are based on previously issued fair value reports.

The purchase price paid for the propylene fractionation business resulted in goodwill of $73.7 million. The goodwill primarily represents the value management has attached to future earnings improvements and to the strategic location of the assets. Earnings from the propylene business are expected to improve substantially from the last few years with the years 2005 and 2006 projected to be peak years in the petrochemical business cycle based on industry forecasts. The propylene fractionation assets are located in Mont Belvieu, Texas on the Gulf Coast, the largest natural gas liquids and petrochemical marketplace in the U.S. The assets have access to substantial supply from major Gulf Coast and central U.S. producers of refinery grade propylene. The polymer grade products produced at the facility have competitive advantages because of distribution direct to customers via affiliated pipelines and through an affiliated export facility. For additional information regarding our goodwill, see Note 8.

Combined pro forma effect of Mid-America, Seminole, Diamond-Koch and Acadian Gas business acquisitions

The following table presents unaudited pro forma financial information incorporating the historical (pre-acquisition) financial results of the following acquired businesses:

- D-K storage (acquired January 1, 2002) and propylene fractionation (acquired February 1, 2002);
- Mid-America and Seminole (both acquired July 31, 2002); and
- Acadian Gas (acquired April 1, 2001).

Our historical Statements of Consolidated Operations and Comprehensive Income reflect the operations of each acquired business since their respective acquisition dates.

The following pro forma information has been prepared as if the acquisitions had been completed on January 1 of the respective periods presented as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon data currently available to and certain estimates and assumptions made by management. As a result, this information is not necessarily indicative of our financial results had the transactions actually occurred on these dates. Likewise, the unaudited pro forma information is not necessarily indicative of our future financial results.

Pro forma net income for each year includes (among other pro forma adjustments) the impact of interest expense associated with the 364-Day Term Loan we used to fund the Mid-America and Seminole acquisitions. The pro forma results for 2001 assume that the initial $1.2 billion borrowed under this facility was outstanding during the entire year. The pro forma results for 2002 reflect our actual repayment of a portion of this debt using proceeds and contributions related to our October 2002 equity offering. The pro forma earnings data do not reflect our January 2003 equity offering nor the Operating Partnership's January 2003 issuance of Senior Notes C or February 2003 issuance of Senior Notes D. The proceeds from these fiscal 2003 equity and debt offerings were used to fully repay the 364-Day Term Loan by the end of February 2003. For additional information regarding these subsequent events, see Note 21.

	For Year Ended December 31,	
	2002	2001
PRO FORMA EARNINGS DATA		
Revenues	$ 3,784,286	$ 3,952,896
Operating income	275,272	384,381
Net income	$ 130,528	$ 252,241
Income before minority interest	$ 137,391	$ 259,629
Less: General partner interest	(11,013)	(5,708)
Net income before minority interest available to Limited Partners	126,378	253,921
Less: Minority interest	(6,863)	(7,387)
Net income available to Limited Partners	$ 119,515	$ 246,534
PRO FORMA BASIC EARNINGS PER UNIT		
Numerator:		
Net income before minority interest available to Limited Partners	$ 126,378	$ 253,921
Net income available to Limited Partners	$ 119,515	$ 246,534
Denominator, weighted-average Units outstanding	155,454	139,452
Pro forma diluted earnings per Unit:		
Net income before minority interest available to Limited Partners	$ 0.81	$ 1.82
Net income available to Limited Partners	$ 0.77	$ 1.77
PRO FORMA DILUTED EARNINGS PER UNIT		
Numerator:		
Net income before minority interest available to Limited Partners	$ 126,378	$ 253,921
Net income available to Limited Partners	$ 119,515	$ 246,534
Denominator, weighted-average Units outstanding	176,490	170,786
Pro forma basic earnings per Unit:		
Net income before minority interest available to Limited Partners	$ 0.72	$ 1.49
Net income available to Limited Partners	$ 0.68	$ 1.44

5. INVENTORIES

Our inventories were as follows at the dates indicated:

	December 31,	
	2002	2001
Working inventory	$ 131,769	$ 29,393
Forward-sales inventory	35,600	33,549
Inventory	$ 167,369	$ 62,942

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. 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 2), 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.

For the years ended December 31, 2002, 2001 and 2000, we recognized LCM adjustments of approximately $6.3 million, $40.7 million and $6.9 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, 2002	December 31, 2001
Plants and pipelines	5-35	$ 2,860,180	$ 1,398,843
Underground and other storage facilities	5-35	283,114	127,900
Transportation equipment	3-35	5,118	3,736
Land		23,817	15,517
Construction in progress		49,586	98,844
Total		3,221,815	1,644,840
Less accumulated depreciation		410,976	338,050
Property, plant and equipment, net		$ 2,810,839	$ 1,306,790

Depreciation expense for the years ended December 31, 2002, 2001 and 2000 was $72.5 million, $43.4 million and $33.3 million, respectively.

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 method. The investments in and advances to these unconsolidated affiliates are grouped according to the operating 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:

	Ownership Percentage	December 31, 2002	December 31, 2001
Accounted for on equity basis:			
Fractionation:			
BRF	32.25%	$ 28,293	$ 29,417
BRPC	30.00%	17,616	18,841
Promix	33.33%	41,643	45,071
La Porte	50.00%	5,737	
OTC	50.00%	2,178	
Pipeline:			
EPIK	50.00%	11,114	14,280
Wilprise	37.35%	8,566	8,834
Tri-States	33.33%	25,552	26,734
Belle Rose	41.67%	11,057	11,624
Dixie	19.88%	36,660	37,558
Starfish	50.00%	28,512	25,352
Neptune	25.67%	77,365	76,880
Nemo	33.92%	12,423	12,189
Evangeline	49.50%	2,383	2,578
Octane Enhancement:			
BEF	33.33%	54,894	55,843
Accounted for on cost basis:			
Processing:			
VESCO	13.10%	33,000	33,000
Total		$ 396,993	$ 398,201

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

	Ownership Percentage	For Year Ended December 31, 2002	2001	2000
Fractionation:				
BRF	32.25%	$ 2,427	$ 1,583	$ 1,369
BRPC	30.00%	997	1,161	(284)
Promix	33.33%	3,936	4,201	5,306
La Porte	50.00%	(559)		
OTC	50.00%	378		
Pipelines:				
EPIK	50.00%	4,688	345	3,273
Wilprise	37.35%	948	472	497
Tri-States	33.33%	1,959	1,565	2,499
Belle Rose	41.67%	203	103	301
Dixie	19.88%	1,231	2,092	751
Starfish	50.00%	7,346	4,122	
Ocean Breeze	25.67%	-	32	
Neptune	25.67%	2,111	4,081	
Nemo	33.92%	1,077	75	
Evangeline	49.50%	(58)	(145)	
Octane Enhancement:				
BEF	33.33%	8,569	5,671	10,407
Total		$ 35,253	$ 25,358	$ 24,119

At December 31, 2002, our share of accumulated earnings of equity method unconsolidated affiliates that had not been remitted to us was approximately $15.4 million. In addition, our initial investment in Promix, La Porte, Dixie, Neptune and Nemo 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, 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 goodwill inherent in Dixie's excess cost is subject to periodic impairment testing; therefore, it and is not amortized. The following table summarizes our excess cost information:

	Initial Excess Cost	Unamortized balance at December 31, 2002	Unamortized balance at December 31, 2001	Amortization charged against equity earnings during 2002	Amortization Period
Fractionation segment:					
Promix	$ 7,955	$ 6,596	$ 7,083	$ 398	20 years
La Porte	873	833	n/a	40	35 years
Pipelines segment:					
Dixie					
Attributable to pipeline assets	28,448	26,074	26,887	813	35 years
Goodwill	9,246	8,827	8,827	n/a	n/a
Neptune	12,768	12,039	12,404	365	35 years
Nemo	727	697	718	21	35 years

As used in the following condensed financial data, gross operating margin represents operating income before applicable depreciation and amortization expense and selling, general and administrative costs. Gross operating margin is an important measure of the profitability of assets owned by our unconsolidated affiliates. We regularly evaluate our consolidated operations on the same basis. Operating income represents earnings before non-operating income and expense items such interest expense and interest income. The equity earnings we record from these investments represent our share of the net income of each.

Fractionation segment:

At December 31, 2002, the Fractionation segment included the following unconsolidated affiliates accounted for using the equity method:

- *Baton Rouge Fractionators LLC* ("BRF") – an approximate 32.25% 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 33.33% 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 are precluded from consolidating its financial statements with our financial statements.
- *Olefins Terminal Corporation* ("OTC") – a 50% interest in a polymer grade propylene export facility located in Seabrook, Texas. As with La Porte, we do not exercise management control over OTC and are precluded from consolidating its financial statements with our financial statements.

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.

	As Of or For The Year Ended December 31, 2002	2001	2000
BALANCE SHEET DATA:			
Current assets	$ 23,496	$ 27,424	
Property, plant and equipment, net	250,096	251,519	
Total assets	$ 273,592	$ 278,943	
Current liabilities	$ 11,229	$ 9,950	
Other liabilities	6,800		
Combined equity	255,563	268,993	
Total liabilities and combined equity	$ 273,592	$ 278,943	
INCOME STATEMENT DATA:			
Revenues	$ 78,350	$ 76,480	$ 71,287
Gross operating margin	40,215	36,321	33,240
Operating income	23,464	22,396	19,997
Net income	23,399	22,738	20,661

Pipelines segment:

At December 31, 2002, our Pipelines operating segment included the following unconsolidated affiliates accounted for using the equity method:

- *EPIK Terminalling L.P.* and *EPIK Gas Liquids, LLC* (collectively, "EPIK") – a 50% aggregate interest in an NGL export terminal located in southeast Texas. In March 2003, we purchased the remaining ownership interests in EPIK for $19 million plus certain post-closing purchase price adjustments, at which time EPIK became a consolidated subsidiary of ours (see Note 21). Prior to our purchase of the remaining interests, we did not exercise management control over EPIK and were precluded from consolidating its financial statements with our financial statements.
- *Wilprise Pipeline Company, LLC* ("Wilprise") – a 37.35% interest in an NGL pipeline system located in southeastern Louisiana.
- *Tri-States NGL Pipeline LLC* ("Tri-States") – an aggregate 33.33% interest in an NGL pipeline system located in Louisiana, Mississippi and Alabama.
- *Belle Rose NGL Pipeline LLC* ("Belle Rose") – a 41.67% interest in an NGL pipeline system located in south Louisiana.
- *Dixie Pipeline Company* ("Dixie") – an aggregate 19.88% 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 a natural gas gathering system 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 LLC* ("Neptune") – a 25.67% interest in the natural gas gathering and transmission 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 33.92% interest in a natural gas gathering system located in the Gulf of Mexico offshore Louisiana that became operational in August 2001.
- *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.

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:

	As Of or For The Year Ended December 31,		
	2002	**2001**	**2000**
BALANCE SHEET DATA:			
Current assets	$ 76,930	$ 68,325	
Property, plant and equipment, net	510,483	515,327	
Other assets	47,501	50,265	
Total assets	$ 634,914	$ 633,917	
Current liabilities	$ 60,484	$ 62,347	
Other liabilities	56,230	57,965	
Combined equity	518,200	513,605	
Total liabilities and combined equity	$ 634,914	$ 633,917	
INCOME STATEMENT DATA:			
Revenues	$ 303,567	$ 305,404	$ 96,270
Gross operating margin	112,455	98,682	51,414
Operating income	65,855	54,459	41,757
Net income	56,736	41,015	31,241

Octane Enhancement segment:

At December 31, 2002, the Octane Enhancement segment included our 33.33% interest in *Belvieu Environmental Fuels* ("BEF"), a facility located in southeast Texas that produces motor gasoline additives to enhance octane. The BEF facility currently produces MTBE. The production of MTBE is driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation and as an additive to increase octane in motor gasoline. Any changes to these oxygenated fuel programs that enable localities to elect to not participate in these programs, lessen the requirements for oxygenates or favor the use of non-isobutane based oxygenated fuels will reduce the demand for MTBE and could have an adverse effect on our results of operations.

In recent years, MTBE has been detected in municipal and private water supplies resulting in various legal actions. BEF has not been named in any MTBE legal action to date. In light of these developments, we and the other two partners of BEF are actively compiling a contingency plan for the BEF facility should MTBE be banned. We are currently evaluating a possible conversion of the facility from MTBE production to alkylate production. In addition to MTBE's value in reducing air pollution, it is a significant source of octane in the U.S. motor gasoline pool. Octane is a critical component of motor gasoline. Therefore, we believe that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in gasoline and that alkylate would be an economic and effective substitute. We are currently conducting a detailed engineering study that is expected to be completed by the end of 2003, at which time we expect a more definitive conversion cost estimate will be available. The cost to convert the facility will depend on the type of alkylate process chosen and level of alkylate production desired by the partnership.

Balance sheet information for the last two years and results of operations data for the last three years for BEF are summarized below:

	As Of or For The Year Ended December 31, 2002	2001	2000
BALANCE SHEET DATA:			
Current assets	$ 37,237	$ 29,301	
Property, plant and equipment, net	129,019	140,009	
Other assets	9,050	10,067	
Total assets	$ 175,306	$ 179,377	
Current liabilities	$ 16,787	$ 13,352	
Other liabilities	4,017	3,438	
Partners' equity	154,502	162,587	
Total liabilities and Partners' equity	$ 175,306	$ 179,377	
INCOME STATEMENT DATA:			
Revenues	$ 229,358	$ 213,734	$ 258,180
Gross operating margin	71,537	28,701	43,328
Operating income	25,461	15,984	30,529
Net income	25,707	17,014	31,220

Processing segment:

At December 31, 2002, 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 December 31, 2002 and 2001:

		At December 31, 2002		At December 31, 2001	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Shell natural gas processing agreement	$ 206,331	$ (23,015)	$ 183,201	$ (11,962)	$ 194,369
Mont Belvieu Storage II contracts	8,127	(232)	7,895		
Mont Belvieu Splitter III contracts	53,000	(1,388)	51,612		
Toca-Western natural gas processing contracts	11,096	(326)	10,861		
Toca-Western NGL fractionation contracts	20,041	(585)	19,457		
Venice contracts *(a)*	4,639		4,635		
MBA acquisition goodwill *(b)*	8,979			(1,122)	7,857
Total	$ 312,213	$ (25,546)	$ 277,661	$ (13,084)	$ 202,226

(a) Amortization will commence when contracted-volumes begin to be processed in 2003.
(b) Amount reclassified to Goodwill on January 1, 2002 per transition provisions of SFAS 142.

At December 31, 2002, our intangible assets consisted of:

- the Shell natural gas processing agreement that we acquired as part of the TNGL acquisition in August 1999;
- certain storage and propylene fractionation contracts we acquired in connection with the Diamond-Koch acquisitions in January and February 2002;
- certain natural gas processing and NGL fractionation contracts we acquired in connection with the Toca-Western acquisition in June 2002; and
- certain NGL-related contracts (the "Venice contracts") we acquired during the third quarter of 2002.

The following table shows amortization expense associated with our intangible assets for the years ended December 31, 2002, 2001 and 2000:

	For Year Ended December 31,		
	2002	**2001**	**2000**
Shell natural gas processing agreement	$ 11,054	$ 7,260	$ 3,576
Mont Belvieu Storage II contracts	232		
Mont Belvieu Splitter III contracts	1,388		
Toca-Western natural gas processing contracts	326		
Toca-Western NGL fractionation contracts	585		
MBA acquisition goodwill *(a)*		449	453
Total	$ 13,585	$ 7,709	$ 4,029

(a) Our MBA acquisition goodwill is no longer subject to amortization under SFAS 142 guidelines.

The value of the Shell natural gas processing agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term (currently $11.1 million annually from 2002 through 2019). The values of the propylene fractionation and storage contracts acquired from Diamond-Koch are being amortized on a straight-line basis over the economic life of the assets to which they relate, which is currently estimated at 35 years. The Toca-Western natural gas processing contracts are being amortized over the expected 20-year remaining life of the natural gas supplies supporting these contracts. The value of the Toca-Western NGL fractionation contracts is being amortized over the expected 20-year remaining life of the assets to which they relate. The value of the Venice contracts will be amortized over 14 years beginning in the third quarter of 2003.

For 2003, amortization expense attributable to these intangible assets is currently estimated at $14.5 million. Based on information currently available, we expect that amortization expense relating to existing intangibles will increase to $14.7 million during each of the years 2004 through 2007.

Goodwill

At December 31, 2002, the value of goodwill was $81.5 million. Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is comprised of the following (values as of December 31, 2002):

- $73.6 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002; and,
- $7.9 million related to the July 1999 purchase of an additional ownership interest in MBA, which in turn owned an interest in our Mont Belvieu NGL fractionation facility.

Our goodwill amounts are classified as part of the Fractionation segment since they are related to assets recorded in this operating segment. At December 31, 2001, the goodwill associated with the MBA acquisition was recorded as part of our intangible assets.

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 adoption of SFAS No. 142, the only goodwill amortization we recorded was that associated with the MBA acquisition from July 1999. Due to the immaterial nature of such amortization expense (approximately $0.4 million per year), the pro forma effect of not amortizing this goodwill in 2001 or 2000 would have had a negligible effect on our net income and earnings per Unit (both basic and diluted).

9. DEBT OBLIGATIONS

Our debt consisted of the following at:

	December 31, 2002	December 31, 2001
Borrowings under:		
364-Day Term Loan, variable rate, due July 2003	$ 1,022,000	
364-Day Revolving Credit facility, variable rate, due November 2004	99,000	
Multi-Year Revolving Credit facility, variable rate, due November 2005	225,000	
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	$ 350,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Seminole Notes, 6.67% fixed rate, $15 million due each December, 2002 through 2005	45,000	
Total principal amount	2,245,000	854,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,774	1,653
Less unamortized discount on:		
Senior Notes A	(81)	(117)
Senior Notes B	(230)	(258)
Less current maturities of debt	(15,000)	-
Long-term debt	$ 2,231,463	$ 855,278

The table above does not reflect the issuance of our $350 million principal amount Senior Notes C in January 2003 and $500 million principal amount Senior Notes D in February 2003 nor does it reflect the repayment of debt using proceeds from our January 2003 equity offering. We used a combination of proceeds from the issuance of Senior Notes C and D and the January 2003 equity offering to completely repay the 364-Day Term Loan by the end of February 2003 (see the section titled "*General description of debt—364-Day Term Loan*" within this note for additional information regarding the use of proceeds to extinguish this debt). For additional information regarding subsequent events affecting our debt balances, see Note 21.

As to the assets of our subsidiary, Seminole Pipeline Company, our $2.2 billion in senior indebtedness at December 31, 2002 is structurally subordinated and ranks junior in right of payment to the $45 million of indebtedness of Seminole Pipeline Company. 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, 2002 reflect the classification of such debt obligations at March 7, 2003.

Letters of credit

At December 31, 2002, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Revolving Credit facility, of which $2.4 million was outstanding.

Parent-Subsidiary guarantor relationships

Enterprise Products Partners L.P. (the "MLP", on a stand-alone basis) acts as guarantor of certain of the Operating Partnership's debt obligations. These parent-subsidiary guaranty provisions exist under all of our debt obligations with the exception of the Seminole Notes. The Seminole Notes are unsecured obligations solely of

Seminole Pipeline Company. If the Operating Partnership were to default on any guaranteed debt obligation, the MLP would be responsible for full payment of that obligation.

General description of debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2002.

364-Day Term Loan. The Operating Partnership entered into a $1.2 billion senior unsecured 364-day term loan to fund the Mid-America and Seminole acquisitions in July 2002. We applied proceeds of $178.8 million from our October 2002 equity offering to partially repay this loan. We used $252.8 million of the $258.9 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 completely repay the 364-Day Term Loan by end of February 2003 (see Note 21). Base variable interest rates under this facility generally bore interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent or (2) a Eurodollar rate. Whichever base interest rate we selected, the rate was increased by an appropriate applicable margin (as defined within the loan agreement). During 2002, the weighted-average interest rate charged was 3.10%, with the range of rates being between 4.88% and 2.88%. This facility contained various covenants similar to those of our revolving credit facilities. We were in compliance with these covenants at December 31, 2002.

364-Day Revolving Credit facility. In November 2000, , our Operating Partnership entered in a 364-Day revolving credit agreement. Currently, the stand-alone borrowing capacity under this credit facility is $230 million with the maturity date for any amount outstanding being November 2003. We have the option to convert any revolving credit balance outstanding at maturity to a one-year term loan (due November 2004) in accordance with the terms of the credit agreement. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. We applied $60.0 million in proceeds from our February 2003 issuance of Senior Notes D to reduce the balance outstanding under this facility during 2003 (see Note 21).

As defined by the credit agreement, variable interest rates charged under this facility generally bear interest at either (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus one-half percent 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. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.51%, with the range of rates being between 4.75% and 2.37%.

The 364-Day Revolving Credit facility 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 quarter. As defined within 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, 2002. The MLP has entered into an unsecured and unsubordinated guarantee of this debt. This debt is non-recourse to the General Partner.

Multi-Year Revolving Credit facility. In conjunction with the 364-Day Revolving Credit facility, our Operating Partnership entered into a five-year revolving credit facility that includes a sublimit capacity of $75 million for standby letters of credit. Currently, the stand-alone borrowing capacity under this credit facility is $270 million. This credit facility is guaranteed by the MLP through an unsecured guarantee. In addition, our borrowings under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. The interest rates charged under this facility are determined in the same manner as that described under our 364-Day Revolving Credit facility. During 2002, the weighted-average interest rate charged for borrowings under this facility was 2.37%, with the range of rates being between 4.75% and 2.00%.

This facility contains various covenants similar to those of our 364-Day Revolving Credit facility. (please refer to our discussion regarding restrictive covenants of the “364-Day Revolving Credit facility” within this “General description of debt” section). We were in compliance with these covenants at December 31, 2002.

Senior Notes A and B. These fixed-rate notes are an unsecured obligation of the Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. Both notes are guaranteed by the MLP through an unsecured and unsubordinated guarantee and are non-recourse to the General Partner. These notes were issued under an indenture containing certain covenants and are subject to a make-whole redemption right. 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, 2002.

MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, our Operating Partnership entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by MLP through an unsecured and unsubordinated guarantee. The indenture agreement for this loan contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable within 120 days if our credit ratings decline below a Baa3 rating by Moody's (currently Baa2) and below a BBB- rating by Standard and Poors (currently BBB). Under these circumstances, the trustee (as defined within the loan agreement) may, and if requested to do so by holders of at least 25% of the principal amount of the underlying bonds, accelerate the maturity of the MBFC Loan. Should this acceleration occur, the entire principal balance of the MBFC Loan and all related accrued and unpaid interest would become immediately due and payable. If such an event occurred, we would have the option of (1) to redeem the MBFC Loan or (2) to provide an alternate credit agreement to support our obligation under the MBFC Loan. We would have 120 days to exercise these options upon receiving notice of the decline in our credit ratings.

The MBFC Loan agreement contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility and restrictions regarding mergers. We were in compliance with these covenants at December 31, 2002.

Seminole Notes. As a result of our acquisition of 78.4% of Seminole in July 2002, we are required to consolidate its debt with our other debt obligations. At December 31, 2002, Seminole had $45 million in fixed-rate senior unsecured notes, of which $15 million is due annually each December through December 2005. The Seminole notes contain various covenants, such as minimum net worth requirements and those restricting Seminole's ability to borrow additional funds. Seminole was in compliance with these covenants at December 31, 2002.

10. CAPITAL STRUCTURE

Our Common Units, Subordinated Units and the convertible Special Units represent limited partner interests in the Company, which entitle the holders thereof to participate in distributions and exercise the rights or privileges available to limited partners 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". Subordinated Units and Special Units are non-voting until their conversion to Common Units.

On February 27, 2002, our General Partner approved a two-for-one split of each class of the partnership Units. The partnership 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. In October 2002, we completed a public offering of 9,800,000 Common Units from which we received net proceeds before offering expenses of approximately $183.3 million, including our General Partner's $3.6 million in capital contributions. The proceeds from this offering were primarily used to repay debt. In January 2003, we completed a public offering of 14,662,500 Common Units from which we received net proceeds of approximately $258.9 million, including our General Partner's $5.3 million in capital contributions (see Note 21).

Our Partnership Agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the Common and Subordinated Unitholders and the General Partner will receive. 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. Normal allocations according to percentage interests are done only, however, after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated 100% to the General Partner.

As an incentive, the General Partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. On December 17, 2002, we amended our Partnership Agreement to eliminate the General Partner's right to receive 50% of the total cash distributions with respect to that portion of quarterly cash distributions that exceeds $0.392 per Unit. Under the terms of this amendment, our General Partner capped its incentive distribution rights at 25% of the total cash distributions with respect to that portion of quarterly cash distributions that exceeds $0.3085 per Unit. No consideration was paid to the General Partner to give up this right. As amended, the General Partner's quarterly incentive distribution thresholds are as follows:

- 1% of quarterly cash distributions up to $0.253 per Units;
- 14.1% of quarterly cash distributions that exceed $0.253 per Unit up to $0.3085 per Unit; and
- 24.2% of quarterly cash distributions that exceed $0.3085 per Unit.

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 without the approval of Unitholders. During the Subordination Period (as described under "Subordinated Units" below), however, we are limited with regards to the number of equity securities that we may issue that rank senior to Common Units or an equivalent number of securities ranking on a parity with our Common Units, without the approval of the holders of at least a Unit Majority. This limitation does not apply to the issuance of Common Units upon conversion of EPCO's Subordinated Units, issuances pursuant to employee benefit plans, the conversion of the General Partner interest as a result of its withdrawal, or issuances in connection with acquisitions or capital improvements that are accretive on a pro forma per Unit basis (as defined within the Partnership Agreement). A Unit Majority is defined as at least a majority of the outstanding Common Units during the Subordination Period, excluding Common Units held by the General Partner and its affiliates, and at least a majority of the outstanding Common Units after the Subordination Period. For those acquisitions and other transactions that do not meet the aforementioned exceptions, we have 54,550,000 Units available (and unreserved) at December 31, 2002 for general partnership purposes during the Subordination Period.

Subordinated Units. The Subordinated Units have no voting rights until converted into Common Units at the end of the Subordination Period. The Subordination Period will generally extend until the first day of any quarter beginning after June 30, 2003 when the Conversion Tests have been satisfied. Generally, the Conversion Test will have been satisfied when we have paid from Operating Surplus and generated from Adjusted Operating Surplus the minimum quarterly distribution on all Units for each of the three preceding four-quarter periods. Upon expiration of the Subordination Period, all remaining Subordinated Units will convert into Common Units on a one-for-one basis and will thereafter participate pro rata with the other Common Units in distributions of Available Cash.

The Partnership Agreement stipulates that 50% of these may undergo an early conversion into Common Units should certain criteria be satisfied. As a result of meeting the initial criteria, 10,704,936 Subordinated Units (or 25%) converted into Common Units on May 1, 2002. Should the remaining criteria continue to be satisfied through the first quarter of 2003, an additional 25% of these Units would undergo an early conversion into Common Units on May 1, 2003. After that, the remaining 50% would convert on August 1, 2003 if the balance of the conversion requirements are met.

Special Units. The Special Units issued to Shell in conjunction with the 1999 TNGL acquisition and a related contingent unit agreement do not accrue distributions and are not entitled to cash distributions until their conversion into Common Units on a one for one basis. For financial accounting and tax purposes, the Special Units are not allocated any portion of net income; however, for tax purposes, the Special Units are allocated a certain amount of depreciation until their conversion into Common Units.

We issued 29 million Special Units to Shell in August 1999 in connection with TNGL acquisition. Subsequently, Shell met certain performance criteria in 2000 and 2001 that obligated us to issue an additional 12 million Special Units to Shell – 6.0 million were issued in August 2000 and 6.0 million in August 2001 under a contingent unit agreement. Of the cumulative 41 million Special Units issued, 31 million have already converted to Common Units (2.0 million in August 2000, 10.0 million in August 2001 and 19.0 million in August 2002). The remaining 10.0 million Special Units will convert to Common Units on a one for one basis in August 2003. These conversions have a dilutive impact on basic earnings per Unit since they increase the number of Common Units used in the computation. Special Units are excluded from the computation of basic earnings per Unit because, under the terms of the Special Units, they do not share in income nor are they entitled to cash distributions until they are converted to Common Units.

Under the rules of the New York Stock Exchange, the conversion of Special Units into Common Units required the approval of a majority of Common Unitholders. An affiliate of EPCO, which owns in excess of 55% of the outstanding Common Units, voted its Units in favor of such conversion, which provided the necessary votes for approval.

Treasury Units. During the first quarter of 1999, the 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. The Common Units purchased by 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 held by the Company and the 1999 Trust are not considered to be outstanding.

The 1999 Trust purchased 792,800 Common Units during 2001 at a cost of $18.0 million and 100,000 Common Units during 2002 at a cost of $2.4 million. In November 2001, the 1999 Trust sold 1,000,000 Common Units previously held in treasury to EPCO for $22.6 million. The sales price of the treasury Common Units sold exceeded the purchase price of the Treasury Units by $6.0 million and was credited to Partners' Equity accounts in a manner similar to additional paid-in capital. At December 31, 2002, the 1999 Trust held 427,200 Common Units that are classified as Treasury Units.

Beginning in July 2000 and later modified in September 2001, the General Partner authorized the Company (specifically, "Enterprise Products Partners L.P.", in this context) and the 1999 Trust to repurchase up to two million of our publicly-held Common Units (the "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 the Company were to be retired and Common Units repurchased by the 1999 Trust were to remain outstanding and be accounted for as Treasury Units.

In April 2002, management modified the Buy-Back Program to treat Common Units repurchased by the Company as Treasury Units. For accounting purposes, Units repurchased by the Company will be held in treasury . The Company purchased 432,000 Common Units during 2002 at a cost of $10.3 million. At December 31, 2002, an additional 618,400 Common Units could be repurchased under the Buy-Back Program.

During 2002, 51,959 Common Units were reissued from treasury at their weighted-average cost of $1.2 million to fulfill our obligations under certain employee Common Unit option agreements of EPCO.

Unit History. The following table details the outstanding balance of each class of Units at the end of the periods indicated:

	Limited Partners			
	Common Units	Subordinated Units	Special Units	Treasury Units
Balance, December 31, 1999	90,571,430	42,819,740	29,000,000	534,400
Additional Special Units issued to Coral Energy, LLC in connection with contingency agreement			6,000,000	
Conversion of 2.0 million Coral Energy, LLC Special Units to Common Units	2,000,000		(2,000,000)	
Units repurchased and retired in connection with buy-back program	(56,800)			
Balance, December 31, 2000	92,514,630	42,819,740	33,000,000	534,400
Additional Special Units issued to Coral Energy, LLC in connection with contingency agreement			6,000,000	
Conversion of 10.0 million Coral Energy, LLC Special Units to Common Units	10,000,000		(10,000,000)	
Treasury Units purchased by consolidated Trust	(792,800)			792,800
Treasury Units reissued by consolidated Trust	1,000,000			(1,000,000)
Balance, December 31, 2001	102,721,830	42,819,740	29,000,000	327,200
Conversion of 19.0 million Coral Energy, LLC Special Units to Common Units	19,000,000		(19,000,000)	
Conversion of 10.7 million Subordinated Units to Common Units	10,704,936	(10,704,936)		
Common Units issued in October 2002	9,800,000			
Treasury Units purchased by consolidated Trust and Company	(532,000)			532,000
Balance, December 31, 2002	141,694,766	32,114,804	10,000,000	859,200

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 $0.2250 per Common Unit. The minimum quarterly distribution is not guaranteed and is subject to adjustment as set forth in the Partnership Agreement. With respect to each quarter during the Subordination Period, the Common Unitholders will generally have the right to receive the minimum quarterly distribution, plus any arrearages thereon, and the General Partner will have the right to receive the related distribution on its interest before any distributions of available cash from Operating Surplus are made to the Subordinated Unitholders.

As an incentive, the General Partner's interest in our quarterly distributions is increased after certain specified target levels are met. We made incentive distributions to the General Partner of $9.8 million, $3.2 million and $0.4 million during the years ended December 31, 2002, 2001 and 2000, respectively.

The following table is a summary of cash distributions per Common and Subordinated Unit and related record and payment dates since January 1, 2000:

	Cash Distribution History			
	Per Common Unit	Per Subordinated Unit	Record Date	Payment Date
2000				
1st Quarter	$0.2500	$0.2500	Apr. 28, 2000	May 10, 2000
2nd Quarter	$0.2625	$0.2625	Jul. 31, 2000	Aug. 10, 2000
3rd Quarter	$0.2625	$0.2625	Oct. 31, 2000	Nov. 10, 2000
4th Quarter	$0.2750	$0.2750	Jan. 31, 2001	Feb. 9, 2001
2001				
1st Quarter	$0.2750	$0.2750	Apr. 30, 2001	May 10, 2001
2nd Quarter	$0.2938	$0.2938	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$0.3125	$0.3125	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$0.3125	$0.3125	Jan. 31, 2002	Feb. 11, 2002
2002				
1st Quarter	$0.3350	$0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	$0.3350	$0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter	$0.3450	$0.3450	Oct. 31, 2002	Nov. 12, 2002
4th Quarter	$0.3450	$0.3450	Jan. 31, 2003	Feb. 12, 2003

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

Provision for income taxes is only applicable to the tax obligation of our Seminole pipeline business, which is a corporation and the only entity subject to income taxes in the consolidated group. The following is a summary of the provision for income taxes for Seminole for the period August 1, 2002 through December 31, 2002:

Current:	
Federal tax benefit	($391)
State tax benefit	(55)
	(446)
Deferred:	
Federal	1,812
State	268
	2,080
Provision for Income Taxes	$1,634

The following is a reconciliation of the provision for income taxes at the federal statutory rate to the provision for income taxes:

Taxes computed by applying the federal statutory rate	$1,488
State income taxes (net of federal benefit)	138
Other	8
Provision for income taxes	$1,634

Significant components of deferred income tax assets and liabilities at December 31, 2002 are as follows:

Deferred tax assets:	
Property, plant and equipment	$15,846
Deferred tax liabilities:	
Other	(619)
Net deferred tax assets	$15,227

Based upon the periods in which taxable temporary differences are anticipated to reverse, we believe it is more likely than not that the Company will realize the benefits of these deductible differences. Accordingly, we believe that no valuation allowance is required for the deferred tax assets. However, the amount of the deferred tax asset considered realizable could be adjusted in the future if estimates of reversing taxable temporary differences are revised.

13. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common and Subordinated Units outstanding during the period. In general, diluted earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common, Subordinated and Special Units outstanding during the period. In a period of net operating losses, the Special 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 amount of Common Units outstanding in the following table does not include Treasury Units (either owned by the Company or the Trust, see Note 10). The following table reconciles the number of Units used in the calculation of basic earnings per Unit and diluted earnings per Unit for the years ended December 31, 2002, 2001 and 2000. See Note 21 for information regarding our January 2003 issuance of 14.7 million Common Units.

	For Year Ended December 31,		
	2002	2001	2000
Income before minority interest	$ 98,447	$ 244,650	$ 222,759
General partner interest	(10,663)	(5,608)	(2,597)
Income before minority interest available to Limited Partners	87,784	239,042	220,162
Minority interest	(2,947)	(2,472)	(2,253)
Net income available to Limited Partners	$ 84,837	$ 236,570	$ 217,909
BASIC EARNINGS PER UNIT			
Numerator			
Income before minority interest available to Limited Partners	$ 87,784	$ 239,042	$ 220,162
Net income available to Limited Partners	$ 84,837	$ 236,570	$ 217,909
Denominator			
Common Units outstanding	119,820	96,633	91,395
Subordinated Units outstanding	35,634	42,820	42,820
Total	155,454	139,453	134,215
Basic Earnings per Unit			
Income before minority interest available to Limited Partners	$ 0.56	$ 1.71	$ 1.64
Net income available to Limited Partners	$ 0.55	$ 1.70	$ 1.62
DILUTED EARNINGS PER UNIT			
Numerator			
Income before minority interest available to Limited Partners	$ 87,784	$ 239,042	$ 220,162
Net income available to Limited Partners	$ 84,837	$ 236,570	$ 217,909
Denominator			
Common Units outstanding	119,820	96,633	91,395
Subordinated Units outstanding	35,634	42,820	42,820
Special Units outstanding	21,036	31,334	30,672
Total	176,490	170,787	164,887
Diluted Earnings per Unit			
Income before minority interest available to Limited Partners	$ 0.50	$ 1.40	$ 1.34
Net income available to Limited Partners	$ 0.48	$ 1.39	$ 1.32

14. RELATED PARTY TRANSACTIONS

Relationship with EPCO and its affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates. EPCO is majority-owned and controlled by Dan L. Duncan, Chairman of the Board and a director of the General Partner. In addition, three other members of the Board of Directors (O.S. Andras, Randa D. Williams and Richard H. Bachmann) and the remaining executive and other officers of the General Partner are employees of EPCO. 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 and Subordinated Units held by EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of the members of Mr. Duncan's family, including Ms. Williams (a director of the General Partner). In addition, EPCO and Dan Duncan, LLC collectively own 70% of the General Partner, which in turn owns a combined 2% interest in us.

In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust) owned 2,478,236 Common Units at December 31, 2002. Collectively, EPCO, Dan L. Duncan, the 1998 Trust and the 2000 Trust owned 61.4% of our limited partnership interests at December 31, 2002. We neither direct the actions of either 1998 Trust or the 2000 Trust nor exercise any measure of control over their actions. Accordingly, these two trusts are not consolidated with our businesses and their Common Unit holdings are deemed to be outstanding for purposes of our earnings per Unit computations.

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.

EPCO 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 EPCO Agreement. Under the terms of the EPCO Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through the 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 of formulas set forth in the agreement;
- grant us an irrevocable, non-exclusive worldwide license to all of the EPCO trademarks and trade names used in our business;
- indemnify us against any losses resulting from certain lawsuits; 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 lease payments associated with these assets.

Operating costs and expenses (as shown in the Statements of Consolidated Operations) 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 partnership. In addition, operating costs and expenses include compensation charges for EPCO's employees who operate our facilities.

Pursuant to the EPCO Agreement, we reimburse 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 who manage our business and affairs. Our reimbursement of EPCO's administrative personnel expense is capped (currently at $17.6 million annually – the "Administrative Services Fee"). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to increases of such fee up to ten percent per year during the 10-year term of the EPCO Agreement. Any difference between the actual costs of this "pre-expansion" group of administrative personnel (including costs associated with equity-based awards granted to certain individuals within this group) and the fee we pay will be borne solely by EPCO. The actual amounts incurred by EPCO did not materially exceed the capped amounts for any periods. We also reimburse EPCO for the compensation of 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.

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.

- EPCO is the operator of the facilities owned by BEF, of which we own 33.3%. In lieu of charging BEF for the actual cost of providing management services, EPCO charges BEF a management fee. EPCO charged BEF $0.6 million for such services during each of 2002, 2001 and 2000.
- EPCO is also operator of the facilities owned by EPIK, which we now wholly own. Prior to February 2003, we owned only 50% of EPIK. In lieu of charging EPIK for the actual cost of management services, EPCO charges EPIK a management fee. During 2002, 2001 and 2000, EPCO charged EPIK $0.3 million, $0.2 million and $0.3 million, respectively, for such services.
- We have entered into an agreement with EPCO to provide trucking services to us for the loading and transportation of products.
- In the normal course of business, we also buy from and sell NGL products to EPCO's Canadian affiliate.

The following table summarizes our various related party transactions with EPCO for the years ended December 31, 2002, 2001 and 2000:

	For Year Ended December 31,		
	2002	2001	2000
Revenues from consolidated operations			
EPCO	$ 3,630	$ 5,439	$ 4,750
Operating costs and expenses			
EPCO	103,210	62,919	52,861
Selling, general and administrative expenses			
Base fees payable under EPCO Agreement	16,638	15,125	13,750
Other EPCO compensation reimbursement	7,566	4,824	1,930

Relationship with Shell

We have an extensive and ongoing commercial relationship with Shell as a partner, customer and vendor. Shell, through its subsidiary Shell US Gas & Power LLC, currently owns approximately 20.5% of our limited partnership interests and 30.0% of the General Partner. Currently, three members of the Board of Directors of the General Partner (J. A. Berget, J.R. Eagan, and A.Y. Noojin, III) are employees of Shell.

Shell is our single largest customer. During 2002, it accounted for 7.8% of our consolidated revenues. Our revenues from Shell reflect the sale of NGL and petrochemical products to them and the fees we charge them 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 (see below) and the purchase of NGL products from them. The following table shows our revenues and operating costs and expenses with Shell for the years ended December 31, 2002, 2001 and 2000:

	For Year Ended December 31,		
	2002	2001	2000
Revenues from consolidated operations			
Shell	$ 282,820	$ 333,333	$ 292,741
Operating costs and expenses			
Shell	531,712	705,440	736,655

The most significant contract affecting our natural gas processing business is the 20-year Shell processing agreement, which grants us the right to process Shell's current and future production from state and federal waters of the Gulf of Mexico on a keepwhole basis. This is a life of lease dedication, which may extend the agreement well beyond 20 years. Generally, this contract has the following rights and obligations:

- the exclusive right, but not the obligation, to process substantially all of Shell's Gulf of Mexico natural gas production; plus
- the exclusive right, but not the obligation, 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 plants from Shell's natural gas production from such leases; with
- the obligation to re-deliver to Shell the natural gas stream after the mixed NGL stream is extracted.

Under this contract, we are responsible for reimbursing Shell for the market value of the energy we extract from their natural gas stream in the course of performing natural gas processing services for them. Our reimbursement to Shell (which we record as an operating cost) is generally based upon the energy value of the fuel we consume and the NGLs we extract from their natural gas stream (in terms of its Btu content, a measure of heating value). In lieu of collecting a cash fee for our services under this contract, we take ownership of the NGLs we extract from their natural gas stream. These volumes (our "equity NGL production") become part our inventory held for sale. We derive a profit to the extent that the revenues from the ultimate sale and delivery to customers of these NGLs exceeds the costs of extraction and any other ancillary costs such as fractionation fees.

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 three issues of Special Units granted to Shell in connection with this acquisition);
- the purchase of the Lou-Tex Propylene Pipeline System 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 the Gulf of Mexico natural gas pipelines we acquired from El Paso in 2001. 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 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 $2.2 million in letters of credit on behalf of Evangeline.
- We pay EPIK for export services to load product cargoes for our NGL and petrochemical marketing customers.
- We pay Dixie transportation fees for propane movements on their system initiated by our NGL marketing activities.
- We sell high purity isobutane to BEF as a feedstock and purchase certain of BEF's by-products. We also receive transportation fees for MTBE movements on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.
- 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.

The following table summarizes our related party transactions with unconsolidated affiliates for the years ended December 31, 2002, 2001 and 2000:

	For Year Ended December 31,		
	2002	2001	2000
Revenues			
Evangeline	$ 131,635	$ 117,283	
EPIK	259	297	$ 5,070
BEF	50,494	45,778	56,216
Promix	12,697	8,952	57
Other unconsolidated affiliates	1,182	1,374	645
Operating costs and expenses			
EPIK	19,788	7,438	17,600
Dixie	12,184	12,695	11,763
BEF	9,794	8,073	10,640
Promix	18,408	12,676	18,200
Other unconsolidated affiliates	482	193	

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 the 1998 Plan, non-qualified incentive options to purchase a fixed number of our Common Units (the "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 funds the purchase of the Units under the 1998 Plan at fair value in the open market.

Categories of equity-based awards and our general responsibility under each

Equity-based awards granted to certain key operations personnel. Under the EPCO Agreement (see Note 14), we reimburse EPCO for the compensation of all operations personnel it employs on our behalf. This includes the costs attributable to equity-based awards granted to these personnel. When these employees exercise Unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price for the Units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing Treasury Units or by issuing new Common Units. We record the expense associated with these awards in our operating costs and expenses as shown on our Statements of Consolidated Operations.

Equity-based awards granted to certain key expansion-related administrative and management employees. We also reimburse EPCO for the compensation of administrative and management 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 "expansion" group of EPCO employees. When these employees exercise Unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price for the Units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing Treasury Units or by issuing new Common Units. We record the expense associated with these awards in our selling, general and administrative costs as shown on our Statements of Consolidated Operations.

Equity-based awards granted to other key administrative and management employees. In addition, we reimburse EPCO for our share of the costs of certain of its employees in administrative and management positions that were active at the time of our initial public offering in July 1998 who manage our business and affairs. The Administrative Services Fee we pay to EPCO covers our reimbursement for the cost of equity-based awards to this "pre-expansion" group of administrative EPCO employees. EPCO is responsible for the actual costs when the Unit options granted to these pre-expansion administrative employees are exercised. EPCO satisfies its equity-award obligations to these employees by arranging for Common Units to be purchased in the open market. We record the Administrative Service Fee paid to EPCO as a selling, general and administrative expense as shown on our Statements of Consolidated Operations.

Summary of 1998 Plan activity and amounts related to Employees who perform activities on our behalf

EPCO's 1998 Plan is used to issue Unit option awards to the three categories of employees discussed above. The information in the following table shows (i) Unit option activity for all operations and expansion – related administrative/management personnel and (ii) Unit option activity of the pre-expansion administrative/management employees allocable to us under the EPCO Agreement (based on each pre-expansion employee's percentage of time worked on our behalf).

	Number of Units	Weighted-average strike price
Outstanding at December 31, 1999	178,611	$ 1.95
Granted	664,000	$ 9.26
Exercised	(38,180)	$ 1.84
Forfeited	(20,000)	$ 9.00
Outstanding at December 31, 2000	784,431	$ 7.96
Granted	680,000	$ 16.67
Exercised	(150,585)	$ 6.01
Forfeited	(20,000)	$ 9.00
Outstanding at December 31, 2001	1,293,846	$ 12.74
Granted	249,000	$ 23.76
Exercised	(102,604)	$ 6.16
Outstanding at December 31, 2002	1,440,242	$ 15.12
Options exercisable at:		
December 31, 2000	140,431	
December 31, 2001	155,846	
December 31, 2002	383,742	

				Options Exercisable at December 31, 2002	
Range of Strike Prices	Options outstanding at December 31, 2002	Weighted Average Remaining Contractual Life (in Years)	Weighted Average Strike Price	Number Exercisable at December 31, 2002	Weighted Average Strike Price
$.69 - $2.23	52,242	2.16	$ 1.58	52,242	$ 1.98
$7.75 -$9.00	331,500	6.75	$ 8.82	331,500	$ 8.82
$11.81	127,500	7.09	$ 11.81	-	-
$15.93 - $17.63	615,000	8.10	$ 16.30	-	-
$21.22 - $24.73	314,000	9.09	$ 23.61	-	-
	1,440,242			383,742	

The weighted average fair value of options granted was $3.17, $1.86, and $2.23 per option for the fiscal years ended December 31, 2002, 2001, and 2000, respectively.

We apply Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees", in accounting for employee Unit option awards whereby no compensation expense is recorded related to the options granted equal to the market value of the Unit on the date of grant. If compensation expense had been determined based on the Black-Scholes option pricing model value at the grant date for Unit option awards consistent with the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation", our net income and earnings per unit would have been as follows:

	2002	2001	2000
Net income:			
As reported	$95,500	$242,178	$220,506
Pro forma	94,406	241,348	219,844
Basic earnings per unit:			
As reported	$ .55	$ 1.70	$ 1.62
Pro forma	.54	1.69	1.62
Diluted earnings per unit:			
As reported	$ .48	$ 1.39	$ 1.32
Pro forma	.48	1.38	1.32

The effects of applying SFAS No. 123 in the pro forma disclosure above may not be indicative of future amounts as additional awards in future years are anticipated.

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

	2002	2001	2000
Expected life of options	7 years	7 years	7 years
Risk-free interest rate	3.10%	3.83%	6.44%
Expected dividend yield	5.65%	5.30%	10.00%
Expected Unit price volatility	25%	20%	30%

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, 2002, NGL and petrochemical volumes aggregating 4.2 million barrels were due to be redelivered to their owners along with 664 BBtus of natural gas.

Lease Commitments

We lease certain equipment and processing facilities under noncancelable and cancelable operating leases. Minimum future rental payments on such leases with terms in excess of one year at December 31, 2002 are as follows:

2003	$ 7,148
2004	5,081
2005	759
2006	676
2007	506
Thereafter	3,623
Total minimum obligations	$ 17,793

Third-party lease and rental expense included in operating income for the years ended December 31, 2002, 2001 and 2000 was approximately $16.4 million, $13.0 million and $10.6 million.

The operating lease commitments shown above 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 $12.6 million for 2003, $2.1 million for each of the years 2004 through 2009 and $0.7 million from 2010 through 2016. EPCO has assigned to us the purchase options associated with the retained leases. Should we decide to exercise our purchase options under the retained leases (which are at fair market value), up to $26.0 million is expected to be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016.

Purchase Commitments

Product purchase commitments. We have long-term purchase commitments for NGLs, petrochemicals and natural gas with several 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 long-term volume commitments under these contracts.

	NGLs	**Petrochemicals**	**Natural Gas**
	(MBbls)	(MBbls)	(BBtus)
2003	15,986	25,428	23,053
2004	13,172	22,857	20,439
2005	9,580	19,287	18,645
2006	5,910	13,399	18,645
2007	5,400	1,125	18,250
Thereafter	10,800		91,250
	60,848	82,096	190,282

Capital spending commitments. As of December 31, 2002, we had capital expenditure commitments totaling approximately $7.8 million, of which $6.3 million relates to our share of capital projects of unconsolidated affiliates.

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 (see Note 15). At December 31, 2002, there were 1,194,242 options outstanding to purchase Common Units under the 1998 Plan that had been granted to operational and expansion-related administrative 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 to this group was $15.73 per Common Unit. At December 31, 2002, 275,242 of these Unit options were exercisable. An additional 100,000, 570,000 and 249,000 of these Unit options will be exercisable in 2003, 2004 and 2005, respectively.

When these operations and expansion-related administrative employees exercise a Unit option, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price paid for the Units awarded to the employee. We may reimburse EPCO for these costs by either furnishing cash, reissuing Treasury Units or by issuing new Common Units.

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,		
	2002	**2001**	**2000**
(Increase) decrease in:			
Accounts and notes receivable	$ (127,365)	$ 231,532	$ (93,716)
Inventories	(84,254)	11,048	(13,044)
Prepaid and other current assets	15,340	(26,427)	2,352
Intangible assets			(5,226)
Other assets	(3,322)	162	(1,410)
Increase (decrease) in:			
Accounts payable	23,901	(82,075)	18,723
Accrued gas payable	262,527	(178,102)	135,049
Accrued expenses	7,884	(1,576)	4,978
Accrued interest	5,369	14,234	8,743
Other current liabilities	(6,921)	3,073	6,540
Other liabilities	(504)	(9,012)	8,122
Net effect of changes in operating accounts	$ 92,655	$ (37,143)	$ 71,111
Cash payments for interest, net of $1,083, $2,946 and $3,277 capitalized in 2002, 2001 and 2000, respectively	$ 82,535	$ 37,536	$ 17,774

During 2002 and 2001, we completed $1.8 billion in business acquisitions of which the purchase price allocation of each affected various balance sheet accounts. See Note 4 for information regarding the purchase price allocations of these transactions during 2002. During 2001, we acquired Acadian Gas from Shell. Its $225.7 million purchase price was allocated as follows: $83.1 million to current assets, $225.2 million to property, plant and equipment, $2.7 million to investments in unconsolidated affiliates, $83.9 million to current liabilities and $1.4 million to other long-term liabilities.

We record various financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. 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 2002, we made the first of two cash payments to acquire certain processing-related contract rights connected to Venice gas processing facility. Of the initial $4.6 million value of this intangible asset, $2.6 million was reclassified from construction-in-progress and $2.0 million represented the actual cash payment made to the third-party. 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. The remaining $2.0 million is scheduled to be paid during the third quarter of 2003.

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, 2002 and 2001 was $8.8 million and $5.8 million, respectively.

We did not have any cash payments for income taxes during 2002, 2001 or 2000. For additional information regarding our partnership and income taxes, see Note 1 and Note 12.

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, 2002, we had open commodity financial instruments that settle at different dates through December 2003. 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 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, 2002. The fair value of these open positions was a liability of $26,000 (based on market prices at that date).

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 will be 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.

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 are accounted for as cash flow hedges under 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 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 21). The settlement of these instruments resulted in our receipt of $5.4 million of cash. This amount will be 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 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 estimated amount to be reclassified from accumulated other comprehensive income to earnings during 2003 is $0.4 million. With the settlement of the treasury locks, the $3.6 million non-cash mark-to-market liability recorded at December 31, 2002 will be 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, the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, our initial conclusions regarding the application of SFAS No. 133 upon adoption may be altered. As a result, additional SFAS No. 133 transition 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, 2002 and 2001:

Financial instruments	At December 31, 2002 Carrying Value	At December 31, 2002 Fair Value	At December 31, 2001 Carrying Value	At December 31, 2001 Fair Value
Financial assets:				
Cash and cash equivalents	$ 22,568	$ 22,568	$ 137,823	$ 137,823
Accounts receivable	399,415	399,415	260,399	260,399
Commodity financial instruments *(1)*	513	513	9,992	9,992
Interest rate hedging financial instruments *(2)*	203	203	2,324	2,324
Financial liabilities:				
Accounts payable and accrued expenses	663,715	663,715	357,951	357,951
Fixed-rate debt (principal amount)	899,000	1,027,749	854,000	894,005
Variable-rate debt	1,346,000	1,346,000		
Commodity financial instruments *(1)*	539	539	3,206	3,206
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 have 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

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 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. As a result, we established a $10.7 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.

Nature of Operations. 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.

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 operating segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. The 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 Chief Executive Officer 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 polymer grade propylene fractionation services. Processing includes the natural gas processing business and its related NGL marketing activities. Octane Enhancement represents our equity interest in BEF, a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on our measurement of segment gross operating margin. Gross operating margin reported for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and general and administrative expenses. In addition, segment 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 includes intersegment and intrasegment revenues (offset by corresponding intersegment and intrasegment expenses within the segments), which are generally based on transactions made at market-related rates. Our intersegment and intrasegment activities include, but are not limited to, the following types of transactions:

- NGL fractionation revenues from separating our NGL raw-make inventories into distinct NGL products using our fractionation plants for our NGL marketing activities (an intersegment revenue of Fractionation offset by an intersegment expense of Processing);
- liquids pipeline revenues from transporting our NGL volumes from gas processing plants on our pipelines to our NGL fractionation facilities (an intersegment revenue of Pipelines offset by an intersegment expense of Processing); and,
- the transfer sale of our NGL equity production extracted by our gas processing plants to our NGL marketing activities (an intrasegment revenue of Processing offset by an intrasegment expense of Processing).

For additional information regarding our revenue recognition policies, see Note 2.

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries, after elimination of all material intercompany (both intersegment and intrasegment) accounts and transactions. 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 and a means by which we conduct our operations to align our interests with a supplier of raw materials to a facility or a consumer of finished products from a facility. 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 our equity investees (see Note 7) perform supporting or complementary roles to our other business operations. For example, we use the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold by our Processing segment's NGL marketing activities. Another example would be our relationship with the BEF MTBE facility. Our isomerization facilities process normal butane for this plant and our HSC pipeline transports MTBE for delivery to BEF's storage facility on the Houston Ship Channel. For additional information regarding our related party relationships with unconsolidated affiliates, see Note 14.

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,		
	2002	**2001**	**2000**
Revenues *(1)*	$ 3,584,783	$ 3,154,369	$ 3,049,020
Operating costs and expenses *(1)*	(3,382,561)	(2,861,743)	(2,801,060)
Equity in income of unconsolidated affiliates *(2)*	35,253	25,358	24,119
Subtotal	237,475	317,984	272,079
Add: Depreciation and amortization in operating costs and expenses *(3)*	86,029	48,775	35,621
Retained lease expense, net in operating costs and expenses *(4)*	9,124	10,414	10,645
(Gain) loss on sale of assets in operating costs and expenses *(3)*	(1)	(390)	2,270
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615

(1) Amounts are comprised of both third party and related party totals from the Statements of Consolidated Operations and Comprehensive Income
(2) Amount taken from Statements of Consolidated Operations and Comprehensive Income
(3) Amount taken from Statements of Consolidated Cash Flows
(4) Amount represents leases paid by EPCO and the related contribution by the minority interest as reflected on the 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,		
	2002	2001	2000
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615
Depreciation and amortization	(86,029)	(48,775)	(35,621)
Retained lease expense, net	(9,124)	(10,414)	(10,645)
Gain (loss) on sale of assets	1	390	(2,270)
Selling, general and administrative	(42,890)	(30,296)	(28,345)
Consolidated operating income	194,585	287,688	243,734
Interest expense	(101,580)	(52,456)	(33,329)
Interest income from unconsolidated affiliates	139	31	1,787
Dividend income from unconsolidated affiliates	4,737	3,462	7,091
Interest income - other	2,313	7,029	3,748
Other, net	(113)	(1,104)	(272)
Consolidated income before provision for income taxes and minority interest	$ 100,081	$ 244,650	$ 222,759

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

	Operating Segments					Adjs. and Elims.	Consol. Totals
	Fractionation	Pipelines	Processing	Octane Enhancement	Other		
Revenues from third parties:							
2002	$ 592,681	$ 458,427	$ 2,049,202		$ 1,756		$ 3,102,066
2001	301,263	239,489	2,100,224		937		2,641,913
2000	361,919	15,648	2,310,706		1,268		2,689,541
Revenues from related parties:							
2002	19,121	161,727	301,747		122		482,717
2001	23,013	163,941	324,057		1,445		512,456
2000	35,076	12,524	310,269		1,610		359,479
Intersegment and intrasegment revenues:							
2002	203,750	102,330	604,981		401	$ (911,462)	-
2001	158,853	89,907	683,524		389	(932,673)	-
2000	177,963	55,690	630,155		375	(864,183)	-
Total revenues:							
2002	815,552	722,484	2,955,930		2,279	(911,462)	3,584,783
2001	483,129	493,337	3,107,805		2,771	(932,673)	3,154,369
2000	574,958	83,862	3,251,130		3,253	(864,183)	3,049,020
Equity income in unconsolidated affiliates:							
2002	7,179	19,505		$ 8,569			35,253
2001	6,945	12,742		5,671			25,358
2000	6,391	7,321		10,407			24,119
Total gross operating margin by segment:							
2002	129,000	214,932	(17,633)	8,569	(2,241)		332,627
2001	118,610	96,569	154,989	5,671	944		376,783
2000	129,376	56,099	122,240	10,407	2,493		320,615
Segment property (see Note 6):							
2002	444,016	2,166,524	133,888		16,825	49,586	2,810,839
2001	357,122	717,348	124,555		8,921	98,844	1,306,790
Investments in and advances to unconsolidated affiliates (see Note 7):							
2002	95,467	213,632	33,000	54,894			396,993
2001	93,329	216,029	33,000	55,843			398,201
Intangible Assets (see Note 8):							
2002	71,069	7,895	198,697				277,661
2001	7,857		194,369				202,226
Goodwill (see Note 8):							
2002	81,547						81,547

In general, our consolidated results of operations and financial position have been materially affected by acquisitions since late 1999. Our more significant acquisitions during this period were:

- William's Mid-America and Seminole pipelines in July 2002 for $1.2 billion;
- Diamond-Koch's propylene fractionation business in February 2002 for $239 million ;
- Diamond-Koch's NGL and petrochemical storage business in January 2002 for $129.6 million;
- Shell's Acadian Gas pipeline business in April 2001 for $243.7 million;
- El Paso's equity interests in four Gulf of Mexico natural gas pipelines in January 2001 for $113 million; and
- Shell's TNGL natural gas processing and related businesses in August 1999 for approximately $528.8 million.

See Note 4 for a description of acquisitions we completed during 2002.

21. SUBSEQUENT EVENTS

January 2003 Common Unit Offering. In January 2003, we completed a public offering of 14,662,500 Common Units (including 1,912,500 Common Units sold pursuant to the underwriters' over-allotment option) from which we received net proceeds before offering expenses of approximately $258.9 million, including our General Partner's $5.3 million in capital contributions. We used $252.8 million of the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan. The remaining balance of proceeds was used for working capital purposes and offering expenses.

January 2003 Senior Notes Offering. In January 2003, our Operating Partnership issued $350 million in principal amount of 6.375% Senior Notes due 2013 ("Senior Notes C"), from which we received net proceeds before offering expenses of approximately $347.7 million. We used $347.0 million of the proceeds from this offering to repay a portion of the indebtedness outstanding under the 364-Day Term Loan. The remaining balance of proceeds was used for offering expenses.

February 2003 Senior Notes Offering. In February 2003, our Operating Partnership issued $500 million in principal amount of 6.875% Senior Notes due 2033 ("Senior Notes D"), from which we received net proceeds before offering expenses of approximately $489.8 million. We used $421.4 million of the proceeds from this offering to repay the remaining principal balance outstanding under the 364-Day Term Loan. An additional $60.0 million in proceeds was used to reduce the amount outstanding under the 364-Day Revolving Credit facility. The remaining balance of proceeds was used for working capital purposes and offering expenses.

Purchase of remaining 50% interest in EPIK. In March 2003, we purchased the remaining ownership interests in EPIK from Idemitsu LPG USA Corporation for $19.0 million. The purchase price is subject to certain post-closing adjustments that we expect to finalize during the second quarter of 2003.

22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table contains selected quarterly financial data for 2002 and 2001.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2001:				
Revenues	$ 836,315	$ 959,397	$ 723,329	$ 635,328
Operating income	54,417	109,071	87,406	36,794
Income before minority interest	52,804	93,975	75,774	22,097
Minority interest	(534)	(944)	(767)	(227)
Net income	52,270	93,031	75,007	21,870
Net income per Unit, basic	$ 0.38	$ 0.68	$ 0.52	$ 0.14
Net income per Unit, diluted	$ 0.30	$ 0.54	$ 0.43	$ 0.12
For the Year Ended December 31, 2002:				
Revenues	$ 662,054	$ 786,257	$ 943,313	$ 1,193,159
Operating income	(1,104)	39,964	68,356	87,369
Income before minority interest	(17,376)	22,523	36,146	57,154
Minority interest	173	(203)	(1,296)	(1,621)
Net income (loss)	(17,203)	22,320	34,850	55,533
Net income (loss) per Unit, basic	$ (0.13)	$ 0.14	$ 0.20	$ 0.30
Net income (loss) per Unit, diluted	$ (0.13)	$ 0.11	$ 0.18	$ 0.28

We recorded a net loss during the first quarter of 2002 due to commodity hedging losses resulting from an unexpected increase in natural gas prices. Overall, we recorded $51.3 million of commodity hedging losses during 2002 compared to $101.3 million of income from such activities during 2001 (see Note 18). Net income for the second half of 2002 improved relative to the first half of 2002 primarily due to the acquisition of Mid-America and Seminole in July 2002 (see Note 4).

Supplemental Information – Reconciliation of GAAP Financial Statements to Non-GAAP Financial Measures

Operating Activities Cash Flows to EBITDA
(Dollars in Thousands)

	For Year Ended December 31,				
	2002	**2001**	**2000**	**1999**	**1998**
Operating activities cash flows	$ 329,761	$ 283,328	$ 360,870	$ 177,953	$ (9,442)
Reconciliation adjustments:					
Interest expense, excluding amortization component	92,761	51,669	29,594	14,917	14,696
Leases paid by EPCO	(9,033)	(10,309)	(10,537)	(10,557)	(4,010)
Deferred income tax expense, net of provision for current period income taxes	(446)				
Gain (loss) on sale of assets	1	390	(2,270)	(123)	276
Changes in fair market value of financial instruments	(10,213)	5,697			
Minority interest	(2,947)	(2,472)	(2,253)	(1,226)	(102)
Net effect of changes in operating accounts	(92,655)	37,143	(71,111)	(27,906)	63,171
EBITDA including distributions from unconsolidated affiliates excluding equity in earnings of unconsolidated affiliates	$ 307,229	$ 365,446	$ 304,293	$ 153,058	$ 64,589

Operating Activities Cash Flows to Distributable Cash Flow
(Dollars in Thousands)

	For Year Ended December 31,			
	2002	**2001**	**2000**	**1999**
Operating activities cash flows	$ 329,761	$ 283,328	$ 360,870	$ 177,953
Adjustments to reconcile operating activities cash flows to Distributable Cash Flow:				
Add: Proceeds from sale of assets	165	568	92	8
Collection of notes receivable from unconsolidated affiliates			6,519	19,979
Minority interest of General Partner in Operating Partnership's allocation of leases paid by EPCO	92	105	107	108
Less: Sustaining capital expenditures component of total capital expenditures	(7,201)	(5,994)	(3,548)	(2,440)
Deferred income tax expense	(2,080)			
Minority interest in earnings not included in calculation of distributable cash flow	(1,968)			
Net effect of changes in operating accounts not included in calculation of distributable cash flow	(92,655)	25,897	(71,111)	(27,903)
Distributable Cash Flow	$ 226,114	$ 303,904	$ 292,929	$ 167,705

Market and Cash Distribution History for Common Units

The following table sets forth, for the periods indicated, the high and low prices per Common Unit (as reported under the symbol "EPD" on the NYSE) and the amount of quarterly cash distributions paid per Common and Subordinated Unit.

	Price Ranges *(1)*		Cash Distribution History			
	High	**Low**	**Per Common Unit** *(1)*	**Per Subordinated Unit** *(1)*	**Record Date**	**Payment Date**
2001						
1st Quarter	$18.40	$13.25	$0.2750	$0.2750	Apr. 30, 2001	May 10, 2001
2nd Quarter	$21.88	$16.60	$0.2938	$0.2938	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$24.18	$19.75	$0.3125	$0.3125	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$26.30	$21.80	$0.3125	$0.3125	Jan. 31, 2002	Feb. 11, 2002
2002						
1st Quarter	$25.79	$24.94	$0.3350	$0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	$24.50	$16.25	$0.3350	$0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter	$22.23	$15.00	$0.3450	$0.3450	Oct. 31, 2002	Nov. 12, 2002
4th Quarter	$19.80	$16.41	$0.3450	$0.3450	Jan. 31, 2003	Feb. 12, 2003

(1) As appropriate, the historical pricing and other data presented within this table have been adjusted for the two-for-one Unit split that occurred in May 2002.

The quarterly cash distribution amounts shown in the table correspond to the 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. The increased quarterly cash distribution rates are attributable to the growth in cash flow that we have achieved through the completion of new projects, improved operating results and accretive acquisitions. Although the payment of such quarterly cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

As of February 28, 2003, there were approximately 24,667 beneficial owners of our Common Units, which includes an estimated 223 Unitholders of record.

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 review our “*Risk Factors*” below.

Risk Factors

Among the key risk factors that may have a direct impact on our results of operations and financial condition are:

We have significant leverage that may restrict our future financial and operating flexibility.

Our leverage is significant in relation to our partners' capital. At December 31, 2002, our total outstanding debt, which represented approximately 63.9% of our total capitalization, was approximately $2.2 billion. These amounts are before the application of approximately $258.9 million in net proceeds before offering expenses from our January 2003 equity offering, For a description of our debt obligations, please read "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Our liquidity and capital resources — Our debt obligations*" on page 30. For a discussion of subsequent events affecting our financial statements, please see footnote 21 titled "*Subsequent Events*" in the Notes to Consolidated Financial Statements on page 93.

Debt service obligations, restrictive covenants and maturities resulting from this leverage may adversely affect our ability to finance future operations, pursue acquisitions and fund other capital needs, and may make our results of operations more susceptible to adverse economic or operating conditions. Our ability to repay, extend or refinance our existing debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to access the capital markets for future offerings may be limited by adverse market conditions resulting from, among other things, general economic conditions, contingencies and uncertainties that are difficult to predict and beyond our control.

If we are unable to access the capital markets for future offerings, we might be forced to seek extensions for some of our short-term maturities or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit could be more onerous than those contained in our existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility.

A decrease in the difference between NGL product prices and natural gas prices results in lower margins on volumes processed, which would adversely affect our profitability.

The profitability of our operations depends upon the spread between NGL product prices and natural gas prices. NGL product prices and natural gas prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of domestic production;
- the availability of imported oil and gas;
- actions taken by foreign oil and gas producing nations;
- the availability of transportation systems with adequate capacity;
- the availability of competitive fuels;
- fluctuating and seasonal demand for oil, gas and NGLs; and
- conservation and the extent of governmental regulation of production and the overall economic environment.

Our Processing segment is directly exposed to commodity price risks, as we take title to NGLs and are obligated under certain of our gas processing contracts to pay market value for the energy extracted from the natural gas stream. We are exposed to various risks, primarily that of commodity price fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. These pricing risks cannot be completely hedged or eliminated, and any attempt to hedge pricing risks may expose us to financial losses.

A reduction in demand for our products by the petrochemical, refining or heating industries could adversely affect our results of operations.

A reduction in demand for our products by the petrochemical, refining or heating industries, whether because of general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could adversely affect our results of operations. For example:

Ethane. If natural gas prices increase significantly in relation to ethane prices, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale.

Propane. The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters will cause the demand for propane to decline significantly and could cause a decline in the volumes of propane that we extract and transport.

Isobutane. Any reduction in demand for motor gasoline in general or MTBE in particular may similarly reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, our operating margin from selling isobutane will be reduced.

MTBE. A number of states have either banned or currently are considering legislation to ban MTBE. In addition, Congress is contemplating a federal ban on MTBE, and several oil companies have taken an early initiative to phase out the production of MTBE. If MTBE is banned or if its use is significantly limited, the revenues and equity earnings we record related to its production may be materially reduced or eliminated. For additional information regarding MTBE, please read "*Other Items*" on page 40.

Propylene. Any downturn in the domestic or international economy could cause reduced demand for propylene, which could cause a reduction in the volumes of propylene that we fractionate and expose our investment in inventories of propane/propylene mix to pricing risk due to requirements for short-term price discounts in the spot or short-term propylene markets.

Please read "Our Results of Operations" beginning on page 19 for a more detailed discussion of our operations.

A decline in the volume of NGLs delivered to our facilities could adversely affect our results of operations.

Our profitability is materially impacted by the volume of NGLs processed at our facilities. 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 the volume of NGLs delivered to our facilities for processing, thereby reducing revenue and operating income.

Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

As a result of business failures, revelations of material misrepresentations and related financial restatements by several large, well-known companies in various industries over the last year, there have been significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and troubling disclosures by some large, diversified energy companies, the energy industry has been especially impacted by these developments, with the rating agencies downgrading a number of large energy-related companies. Accordingly, in this environment we are exposed to an increased level of credit and performance risk with respect to our customers. If we fail to adequately assess the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness could have an adverse impact on us.

Acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing operations. We may encounter difficulties integrating these acquisitions with our existing businesses without a loss of employees or customers, a loss of revenues, an increase in operating or other costs or other difficulties. In addition, we may not be able to realize the operating efficiencies, competitive advantages, cost savings or other benefits expected from these acquisitions. Future acquisitions may require substantial capital or the incurrence of substantial indebtedness. As a result, our capitalization and results of operations may change significantly following an acquisition, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our Unitholders and our ability to make payments on our debt securities.

The after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate rate. Some or all of the distributions made to Unitholders would be treated as dividend income, and no income, gains, losses or deductions would flow through to Unitholders. Treatment of us as a corporation would cause a material reduction in the anticipated cash flow and after-tax return to the Unitholders, likely causing a substantial reduction in the value of the common units. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. The partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect that impact on us.

Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business. An escalation of political tensions in the Middle East and elsewhere, such as the recent commencement of United States military action in Iraq, could result in increased volatility in the world's energy markets and result in a material adverse effect on our business.

Employees

We do not have any employees. EPCO employs most of the persons necessary for the operation of our business. At December 31, 2002, EPCO had approximately 1,000 employees involved in the management and operations of our business, none of whom were members of a union. We fully reimburse EPCO for the costs of approximately 900 of these employees, with the remainder of this group covered under the fixed-fee payments we make under the EPCO Agreement (for a detailed discussion of the EPCO Agreement, see footnote 14 titled "Related Party Transactions" in the Notes to Consolidated Financial Statements on page 76). In addition to EPCO employees, we have engaged approximately 150 contract maintenance and other personnel who support our operations.

Directors and Officers of Enterprise Products GP, LLC

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

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

J.A. Berget (1)
Vice President and General Manager, Shell Exploration and Production Company

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

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

J.R. Eagan
Chief Financial Officer, Shell Oil Company and Vice President Finance and Commercial Operations, Shell Exploration and Production Company

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

A. Y. Noojin, III (1)
President and Chief Executive Officer, Shell U.S. Gas and Power, LLC

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

Randa D. Williams
President and Chief Executive Officer, privately-held Enterprise Products Company

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Executive Vice President and Chief Financial Officer

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

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Executive Vice President

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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

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

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Senior Vice President, Marketing and Supply

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Vice President, Engineering

Frank A. Chapman
Vice President, Corporate Risk

W. Randall Fowler[3]
Vice President and Treasurer

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Vice President, Texas Operations

Vance L. Harrington
Vice President, Wholesale Propane Marketing

Theodore Helfgott
Vice President, Environmental

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

Michael R. Johnson
Assistant Secretary

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 are used in this annual report.

Acadian Gas	Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001
Accum. OCI	Accumulated Other Comprehensive Income
Asset platform	For a discussion of our "asset platform" please read "Business and Properties—General" beginning on page 1 of this annual report.
Basell	Basell polyolefins and affiliates
Baytank	Odjfell Terminals (Houston) LP
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, an equity investment of EPOLP
Belle Rose	Belle Rose NGL Pipeline LLC, an equity investment of EPOLP
BP	BP PLC and affiliates
BPD	Barrels per day
BRF	Baton Rouge Fractionators LLC, an equity investment of EPOLP
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity investment of EPOLP
Burlington	Burlington Resources Inc. and affiliates
CEO	Chief Executive Officer
CFO	Chief Financial Officer
ChevronPhillips	ChevronPhillips Chemical Company L.P. and affiliates
ChevronTexaco	ChevronTexaco Corp., its subsidiaries and 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 affiliates
CornerStone	CornerStone Propane Partners, L.P. and 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.
Devon Energy	Devon Energy Corporation, its subsidiaries and affiliates
Diamond-Koch	Refers to affiliates of Valero Energy Corporation and Koch Industries, Inc.
DIB	Deisobutanizer
Dixie	Dixie Pipeline Company, an equity investment of EPOLP
Duke	Duke Energy Corporation and its affiliates
El Paso	El Paso Corporation, its subsidiaries and affiliates
E-Oaktree	E-Oaktree, LLC, a subsidiary of the Company of whom 98% of its membership interests were acquired by us from affiliates of Williams in July 2002
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, an equity investment of EPOLP
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the "Operating Partnership")
EPU	Earnings per Unit
Equistar	A joint venture of Lyondell Chemical Company and Millennium Chemicals, Inc.
Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity investment of EPOLP
FASB	Financial Accounting Standards Board

Glossary (continued)

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 14 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 and the Operating Partnership
HSC	Denotes our Houston Ship Channel pipeline system
ICA	Interstate Commerce Act
Isomerization	For a discussion of the isomerization process, please read "The Company's Operations—Fractionation—Isomerization" beginning on page 17 of this annual report.
IPO	Refers to our initial public offering in July 1998
Kinder Morgan	Kinder Morgan Operating LP "A"
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity investment of EPOLP
LIBOR	London interbank offered rate
Mapletree	Mapletree, LLC, a subsidiary of the Company of whom 98% of its membership interests were acquired by us from affiliates of Williams in July 2002
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.
MMcf/d	Million cubic feet per day
MMBbls	Millions of barrels
MMBtu/d	Million British thermal units per day, a measure of heating value
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 20 of this annual report.
Nemo	Nemo Gathering Company, LLC, an equity investment of EPOLP
Neptune	Neptune Pipeline Company LLC, an equity investment of EPOLP
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 20 of this annual report.
NYSE	New York Stock Exchange
Ocean Breeze	Ocean Breeze Pipeline Company, LLC, an equity investment of EPOLP (merged into Neptune during fourth quarter of 2001)
OPIS	Oil Price Information Service
Operating Partnership	Enterprise Products Operating L.P. and its subsidiaries

Glossary (continued)

OTC	Olefins Terminal Corporation, an equity investment of the Company
Promix	K/D/S Promix LLC, an equity investment of EPOLP
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.
S&P	Standard & Poor's Rating Services
Starfish	Starfish Pipeline Company LLC, an equity investment of EPOLP
Straddle plants	A natural gas processing facility situated on a pipeline that is the sole inlet and outlet for the processing facility
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 of EPOLP
VESCO	Venice Energy Services Company, LLC, a cost method investment of EPOLP
Williams	The Williams Companies, Inc. and subsidiaries
Wilprise	Wilprise Pipeline Company, LLC, an equity investment of EPOLP
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. Outstanding Common Units at December 31, 2002 totaled 141,694,766. For a table of the high and low market prices of the Common Units by quarter, see page 96.

In addition to the Common Units, Enterprise had 32,114,804 Subordinated Units and 10,000,000 non-distribution bearing Convertible Special Units outstanding as of December 31, 2002. The Subordinated Units and Convertible Special Units convert to Common Units on a 1:1 basis upon certain events. For a complete description of these units, see page 70.

CASH DISTRIBUTIONS

Enterprise has paid 18 consecutive quarterly cash distributions to Unitholders since its public offering of Common Units in 1998. On January 13, 2003, the Company declared a quarterly distribution of $0.345 per unit. This distribution was made to Unitholders of record as of January 31, 2003. For a summary of the cash distributions paid, see page 74.

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 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 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 his partnership interest. Enterprise provides each unitholder a Schedule K-1 tax package that includes each unitholder's 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 his 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 by telephone 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

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EPD LISTED NYSE

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