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

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2001.

OR

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

For the transition period from ____ to ____.

Commission file number: 1-14323

Enterprise Products Partners L.P.
(Exact name of registrant as specified in its charter)

Delaware	76-0568219
(State or other jurisdiction of incorporation of organization)	(I.R.S. Employer Identification No.)

2727 North Loop West, Houston, Texas 77008-1037
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (713) 880-6500

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

The aggregate market value of the Common Units held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on March 7, 2002, was approximately $465.7 million. This figure assumes that the Enterprise Products 1998 Unit Option Plan Trust, Enterprise Products 2000 Rabbi Trust, EPOLP 1999 Grantor Trust, the directors and executive officers of the General Partner and Shell US Gas & Power LLC were affiliates of the registrant.

The registrant had 51,524,515 Common Units outstanding as of March 7, 2002.

ENTERPRISE PRODUCTS PARTNERS L.P.
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Glossary

The following abbreviations, acronyms or terms used in this Form 10-K are defined below:

Acadian Gas	Acadian Gas LLC and subsidiaries, acquired from Shell in April 2001
Basell	Basell polyolefins and affiliates
BBtu	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 Amoco 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
Btu	British thermal units, a measure of heating value
Company	Enterprise Products Partners L.P. and subsidiaries
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
Dow	Dow Chemical Company and affiliates
Dynegy	Dynegy Inc. and affiliates
EBITDA	Earnings before interest, taxes, depreciation and amortization
EPCO	Enterprise Products Company, an affiliate of the Company
El Paso	El Paso Corporation, its subsidiaries and 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, Millennium Chemicals, Inc. and Occidental Petroleum Corporation
Exxon Mobil	Exxon Mobil Corporation and affiliates
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
General Partner	Enterprise Products GP, LLC, the general partner of the Company and EPOLP
HSC	Denotes our Houston Ship Channel pipeline system
Huntsman	Huntsman Corporation and affiliates
Kinder Morgan	Kinder Morgan Operating LP "A"
LIBOR	London interbank offering rate
Lyondell	Lyondell Petrochemical Company and affiliates
Manta Ray	A Gulf of Mexico offshore Louisiana natural gas pipeline system owned by Manta Ray Offshore Gathering Company, LLC
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
MLP	Denotes the Company as guarantor of certain debt obligations of EPOLP
MBbls	Thousands of barrels
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
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day

Mont Belvieu	Mont Belvieu, Texas
MTBE	Methyl tertiary butyl ether
Nautilus	A Gulf of Mexico offshore Louisiana natural gas pipeline system owned by Nautilus Pipeline Company, LLC
Nemo	Nemo Gathering Company, LLC, an equity investment of EPOLP
Neptune	Neptune Pipeline Company LLC
NGL or NGLs	Natural gas liquid(s)
NYSE	New York Stock Exchange
Ocean Breeze	Ocean Breeze Pipeline Company, LLC
Operating Partnership	EPOLP and its subsidiaries
Phillips	Phillips Petroleum Company and affiliates
Promix	K/D/S Promix LLC, an equity investment of EPOLP
PTR	Plant thermal reduction
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards issued by the FASB
SG and A	Selling, general and administrative costs
Shell	Shell Oil Company, its subsidiaries and affiliates
Starfish	Starfish Pipeline Company, LLC, an equity investment of EPOLP
Sun	Sunoco Inc. and affiliates
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	Williams Energy Marketing & Trading
Wilprise	Wilprise Pipeline Company, LLC, an equity investment of EPOLP
1998 Trust	Enterprise Products 1998 Unit Option Plan Trust, an affiliate of EPCO
1999 Trust	EPOLP 1999 Grantor Trust, a subsidiary of EPOLP
2000 Trust	Enterprise Products 2000 Rabbi Trust, an affiliate of EPCO

PART I

Items 1 and 2. Business and Properties.

General

Enterprise Products Partners L.P., a Delaware limited partnership, is a publicly-traded master limited partnership (NYSE, symbol "EPD") that conducts substantially all of its business through Enterprise Products Operating L.P. (the "Operating Partnership" or "EPOLP"), the Operating Partnership's subsidiaries, and a number of investments with industry partners. Unless the context requires otherwise, references to "we","us","our" or the "Company" are intended to mean Enterprise Products Partners L.P., our Operating Partnership and subsidiaries.

Our company was formed in April 1998 to acquire, own and operate all of the NGL processing and distribution assets of Enterprise Products Company ("EPCO"). Our General Partner, Enterprise Products GP, LLC, owns a 1.0% general partner interest in the Company and a 1.0101% general partner interest in EPOLP. At December 31, 2001, EPCO and its affiliates own 65.2% of our limited partner interests and 70% of the General Partner with affiliates of Shell owning 23.2% of our limited partner interests and 30% of the General Partner. Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008-1038 and our telephone number is 713-880-6500.

We are a leading North American provider of a wide range of midstream energy services to our customers located primarily along the central and western Gulf Coast. Our services include the:

- gathering, transmission and storage of natural gas from both onshore and offshore Louisiana developments;
- purchase and sale of natural gas in south Louisiana;
- processing of natural gas into a merchantable and transportable product that meets industry quality specifications by removing NGLs and impurities;
- fractionation of mixed NGLs produced as by-products of oil and natural gas production into their component products: ethane, propane, isobutane, normal butane and natural gasoline;
- conversion of normal butane to isobutane through the process of isomerization;
- production of MTBE from isobutane and methanol;
- transportation of NGL products to customers by pipeline and railcar;
- production of high purity propylene from refinery-sourced propane/propylene mix;
- import and export of certain NGL and petrochemical products through our dock facilities;
- transportation of high purity propylene by pipeline; and
- storage of NGL and petrochemical products.

Business Strategy

Our business strategy is to (i) capitalize on expected increases in natural gas and NGL production resulting from development activities in the deepwater and continental shelf areas of the Gulf of Mexico, (ii) develop and invest in joint venture projects with strategic partners that will provide the raw materials for the project or purchase the project's end products, (iii) expand our asset base through accretive acquisitions of complementary midstream energy assets from major energy companies that seek to divest "non-core" assets and from companies that are required by regulatory agencies to divest assets, and (iv) increase our fee-based cash flows by investing in fee-based pipelines and other businesses.

Cautionary Statement regarding Forward-Looking Information and Risk Factors

This annual report on Form 10-K contains various forward-looking statements and information that are based on our beliefs and those of the General Partner, as well as assumptions made by and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "forecast," "intend," "could," "believe," "may," and similar expressions and statements regarding the plans and objectives of the Company for future operations, are intended to identify forward-looking statements. Although we and the General Partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor the

General Partner can give any assurance 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 we anticipated, estimated, projected or expected.

An investment in our securities involves a degree of risk. Among the key risk factors that may have a direct bearing on our results of operation and financial condition are:

- competitive practices in the industries in which we compete;
- fluctuations in oil, natural gas and NGL prices and production due to weather and other natural and economic forces;
- operational and systems risks;
- environmental liabilities that are not covered by indemnity or insurance;
- the impact of current and future laws and governmental regulations (including environmental regulations) affecting the NGL industry in general and our operations in particular;
- the loss of a significant customer;
- the use of financial instruments to hedge commodity and other risks which prove to be economically ineffective; and
- the failure to complete one or more new projects on time or within budget.

The prices of natural gas and NGLs 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 oil, natural gas and NGL production and development, the availability of imported oil and natural gas, actions taken by foreign oil and natural gas producing nations and companies, the availability of transportation systems with adequate capacity, the availability of competitive fuels and products, fluctuating and seasonal demand for oil, natural gas and NGLs, and conservation and the extent of governmental regulation of production and the overall economic environment.

In addition, we must obtain access to new natural gas volumes for our processing business in order to maintain or increase gas plant throughput 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 NGL 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.

Lastly, our expectations regarding future capital expenditures are only forecasts regarding these matters. These forecasts may be substantially different from actual results due to various uncertainties including the following key factors: (a) the accuracy of our estimates regarding capital spending requirements, (b) the occurrence of any unanticipated acquisition opportunities, (c) the need to replace unanticipated losses in capital assets, (d) changes in our strategic direction and (e) unanticipated legal, regulatory and contractual impediments with regards to our construction projects.

For a description of the tax and other risks of owning our limited partner interests, see our registration documents (together with any amendments thereto) filed with the SEC on Form S-1/A dated July 21, 1998, Form S-3 dated December 21, 1999 and Form S-3 dated February 23, 2001.

Recent Acquisitions and related developments

During 2001, we completed or initiated approximately $860 million of capital spending on internal growth projects, equity investments and business acquisitions. These include $226 million paid to Shell for the purchase of Acadian Gas (an onshore Louisiana natural gas pipeline system) and a combined $112 million paid to El Paso for equity interests in four Gulf of Mexico natural gas pipelines (primarily offshore systems). During the first quarter of 2002, we completed the purchase of a propylene fractionation facility, 30 hydrocarbon salt dome storage wells and related equipment located in Mont Belvieu, Texas from Diamond-Koch for $368 million.

Also, we issued the last installment of 3.0 million non-distribution bearing, convertible Special Units to Shell in August 2001 under an agreement executed as part of the 1999 TNGL acquisition. The value of these new Units increased the purchase price of the TNGL acquisition by $117 million to a final amount of approximately $529 million.

For a further discussion of the pipeline and storage acquisitions, please see the "Pipelines" discussion on page 8. Additional information regarding the issuance of the new Special Units can be found in Note 7 of the Notes to Consolidated Financial Statements beginning on page F-7.

The Company's Operations

We have five reportable operating segments: Fractionation, Pipelines, Processing, Octane Enhancement and Other. Fractionation primarily includes NGL fractionation, isomerization services, and propylene fractionation. Pipelines consists of liquids and natural gas pipeline systems, storage and import/export terminal services. Processing includes the natural gas processing business and NGL merchant activities. Octane Enhancement represents our equity interest in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other segment consists primarily of fee-based marketing services.

See Note 15 of the Notes to Consolidated Financial Statements for additional segment information including revenues from external customers, segment profit and loss and segment assets.

Fractionation

NGL fractionation

Our NGL fractionation operations include seven NGL fractionators with a combined gross processing capacity of 558 MBPD with a net processing capacity to us of 290 MBPD. A summary of our NGL fractionation facilities at December 31, 2001 is as follows:

NGL Fractionation Facility	Location	Gross Capacity, MBPD	Our Ownership Interest	Our Net Capacity, MBPD
Mont Belvieu	Texas	210	62.5%	131
Norco	Louisiana	70	100%	70
BRF	Louisiana	60	32.24%	19
Promix	Louisiana	145	33.33%	48
Tebone	Louisiana	30	33.7%	10
Venice	Louisiana	36	13.1%	5
Petal	Mississippi	7	100%	7
	Total	558		290

NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or refined from normal butane through the process of isomerization, principally for use in refinery alkylation to enhance the octane content of motor gasoline, in the production of MTBE (an oxygenation additive used in cleaner burning motor gasoline), and in the production of propylene oxide. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

The three principal sources of mixed NGLs fractionated in the United States are (i) domestic gas processing plants, (ii) domestic crude oil refineries and (iii) imports of butane and propane mixtures. When produced at the wellhead, natural gas consists of a mixture of hydrocarbons that must be processed to remove impurities and render the gas suitable for pipeline transportation. Gas processing plants are located near the production areas and separate pipeline quality natural gas (principally methane) from mixed NGLs and other components. After being extracted from natural gas, mixed NGLs are typically transported to a centralized facility for fractionation. Recoveries of mixed NGLs by gas processing plants represent the most important source of throughput for our NGL fractionators and is generally governed by the degree to which NGL prices exceed the cost (principally that of natural gas as a feedstock and as a fuel) of separating the mixed NGLs from the natural gas stream. When operating and extraction costs of gas processing plants are higher than the incremental value of the NGL products that would be gained by NGL extraction, the mixed NGL recovery levels of gas processing plants may be reduced, leading to a reduction in volumes available for NGL fractionation.

Crude oil and condensate production also contain varying amounts of NGLs, which are removed during the refining process and are either fractionated by the refiners themselves or delivered to third-party NGL fractionation facilities like those owned by the Company. The mixed NGLs delivered from domestic gas processing plants and crude oil refineries to our NGL fractionation facilities are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck. We also take delivery of mixed NGL imports through our Houston Ship Channel import terminal, which is connected to our Mont Belvieu complex via pipeline.

The majority of our NGL fractionation facilities process mixed NGL streams for third-party customers and our NGL merchant business by charging them a toll fractionation fee. Toll fee arrangements typically include a base cents per gallon fee for mixed NGLs processed subject to adjustment for changes in certain fractionation expenses. Exclusive to our Norco facility, we are paid for fractionation services by receiving a percentage of NGLs fractionated for third-party customers (i.e., in-kind fees). The results of operation of our NGL fractionation business are dependent upon the volume of mixed NGLs processed and either the level of toll processing fees charged (in toll fee-based operations) or the value of NGLs received (applicable to in-kind fee arrangements only). The NGL fractionation business exhibits little to no seasonal variation. Lastly, we are exposed to the pricing risks of NGLs only to the extent that we receive in-kind fees for our services, since our customers generally retain title to the mixed NGL streams that we process and the NGL products that are ultimately produced.

Management believes that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast gas processing plants, will be available for fractionation in the foreseeable future. These gas processing plants are expected to benefit from anticipated increases in natural gas production from emerging deepwater developments in the Gulf of Mexico offshore Louisiana. Deepwater natural gas production has historically had a higher concentration of NGLs than continental shelf or domestic land-based production along the Gulf Coast. In addition, significant volumes of mixed NGLs are contractually committed to our facilities by joint owners and third-party customers.

Although competition for NGL fractionation services is primarily based on the fractionation fee, the ability of an NGL fractionator to obtain mixed NGLs and distribute NGL products is also an important competitive factor and is a function of the existence of the necessary pipeline and storage infrastructure. NGL fractionators connected to extensive transportation and distribution systems such as ours have direct access to larger markets than those with less extensive connections. We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Our Mont Belvieu NGL fractionator competes directly with three local facilities having an estimated combined processing capacity of 475 MBPD and indirectly with two other Texas facilities having a combined processing capacity of 210 MBPD. In addition, our facilities compete on a more limited basis with two facilities in Kansas and several facilities in Louisiana. Finally, we also compete with a number of producers who operate small NGL fractionators at individual field processing facilities.

Principal NGL fractionation facilities

During 2001, our NGL fractionation facilities processed mixed NGLs at an average rate of 204 MBPD or 70% of capacity, both amounts on a net basis. The following table shows net processing volumes and capacity (both in MBPD) and the corresponding overall utilization rates of our NGL fractionation facilities for the last three years:

NGL Fractionation Facility	For Year Ended December 31, 2001	2000	1999
Mont Belvieu	110	106	78
Norco	41	47	48
BRF	14	15	13
Promix	30	34	30
Other	9	11	15
Total net volume	204	213	184
Net capacity	290	290	264
Utilization rate	70%	73%	70%

Mont Belvieu. We operate one of the largest NGL fractionation facilities in the United States with a gross processing capacity of 210 MBPD at Mont Belvieu, Texas. Mont Belvieu is the hub of the domestic NGL industry because of its proximity to the largest concentration of refineries and petrochemical plants in the United States and its location on a large naturally-occurring salt dome that provides for the underground storage of significant quantities of NGLs. Our Mont Belvieu NGL fractionation facility is supported by long-term fractionation agreements with Burlington Resources, Chevron Texaco and Duke Energy (accounting for 63 MBPD of net processing volume in 2001), each of which is a significant producer of NGLs and a co-owner of the facility. We own an effective 62.5% interest in this facility.

Norco. We own and operate an NGL fractionation facility at Norco, Louisiana. The Norco facility receives mixed NGLs via pipeline from the Yscloskey, Toca and Crawfish gas processing plants in Louisiana and has a gross processing capacity of 70 MBPD. During 2001, long-term in-kind fee arrangements exclusive to this facility accounted for approximately 40 MBPD of processing volume.

BRF. We operate and own a 32.24% interest in BRF, which owns a 60 MBPD NGL fractionation facility and related pipeline transportation assets located near Baton Rouge, Louisiana. The BRF facility processes mixed NGLs provided by the co-owners of the facility (Williams, BP and Exxon Mobil) from production areas in Alabama, Mississippi and southern Louisiana including offshore Gulf of Mexico areas.

Promix. We operate and own a 33.33% interest in Promix, which owns a 145 MBPD NGL fractionation facility located near Napoleonville, Louisiana. The Promix assets include a 315-mile mixed NGL gathering system connected to nine gas processing plants, five NGL salt dome storage wells and a barge loading facility. Promix receives mixed NGLs from numerous gas processing plants located in southern Louisiana.

Isomerization

Our isomerization business includes three butamer reactor units and eight associated DIBs located in Mont Belvieu, Texas, which comprise the largest commercial isomerization complex in the United States. These facilities have an average combined production capacity of 116 MBPD of isobutane. We own the isomerization facilities with the exception of one of the butamer reactor units, which we control through a long-term lease. We operate the facilities.

The following table shows isobutane production and capacity (both in MBPD) and overall utilization for the last three years:

Mont Belvieu Facility	For Year Ended December 31, 2001	2000	1999
Production	80	74	74
Capacity	116	116	116
Utilization rate	69%	64%	64%

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutane and high purity isobutane. The demand for commercial isomerization services depends upon the industry's requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations. Isobutane demand is marginally higher in the spring and summer months due to the demand for isobutane-based clean fuel additives such as MTBE in the production of motor gasoline. The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. The principal uses of isobutane are for alkylation, propylene oxide and in the production of MTBE.

We use the isomerization facilities to convert normal butane into isobutane (including high purity grade) for our toll processing customers, including our isobutane merchant business that is part of our Processing segment. Our larger third-party toll processing customers (such as Lyondell and Huntsman) operate under long-term contracts in which they supply normal butane feedstock and pay us toll processing fees based on the volume of isobutane produced. We, as well as our partners in BEF, use the high purity isobutane produced by these facilities to meet our feedstock obligations of the MTBE plant under tolling arrangements. Our isobutane merchant business uses the isomerization facilities to meet the requirements of its isobutane sales contracts when the processing of Company-owned inventories of normal and/or mixed butanes is necessary. During 2001, 18 MBPD of isobutane production was attributable to our merchant activities, 14 MBPD to BEF-related contracts, with the balance related to various toll processing arrangements.

In the isomerization market, we compete with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage infrastructure. We believe that our isomerization facilities benefit from the integrated nature of the Mont Belvieu complex with its extensive connections to pipeline and storage assets.

Propylene fractionation

Our propylene fractionation business consists of three polymer grade propylene facilities and one chemical grade propylene plant. These assets include a controlling interest in a polymer grade propylene fractionation facility ("Mont Belvieu III") recently purchased from Diamond-Koch (see "2002 developments" below). The following table summarizes our propylene fractionation business assets and ownership at March 1, 2002:

Propylene Fractionation Facility	Location	Gross Capacity, MBPD	Our Effective Ownership Interest	Our Net Capacity, MBPD
Mont Belvieu I	Texas	17	100%	17
Mont Belvieu II	Texas	14	100%	14
Mont Belvieu III	Texas	41	66.67%	27.3
BRPC	Louisiana	23	30%	7
	Total	95		65.3

In general, propylene fractionation plants separate refinery grade propylene (a mixture of propane and propylene) into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade propylene can also be produced from chemical grade propylene feedstock. Likewise, chemical grade propylene is also a by-product of olefin (ethylene) production. Approximately 50% of the demand for polymer grade propylene is attributable to polypropylene, which has a variety of end uses, including packaging film, fiber for carpets and upholstery and molded plastic parts for appliance, automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in plastics, synthetic fibers and foams. Overall, the propylene fractionation business exhibits little seasonality.

During 2001, our propylene fractionation facilities produced at an average rate of 31 MBPD or 82% of capacity, both amounts on a net basis. The table below shows net production volumes and capacity (both in MBPD) and the corresponding overall utilization rates of our facilities for the last three years:

Propylene Fractionation Facility	For Year Ended December 31, 2001	2000	1999
Mont Belvieu I and II	27	29	28
BRPC	4	4	
Total net volume	31	33	28
Net capacity	38	35	31
Utilization rate	82%	94%	90%

We compete with numerous producers of polymer grade propylene, which include many of the major refiners on the Gulf Coast. Generally, the propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our propylene fractionation units have been designed to be cost efficient which allows us to be very competitive in terms of processing fees. In addition, our facilities are connected to extensive pipeline transportation and storage facilities, which provide our customers with operational flexibility.

2002 developments

On February 1, 2002, we completed the purchase of various propylene fractionation assets from affiliates of Valero Energy Corporation and Koch Industries, Inc. (collectively, "Diamond-Koch") and certain inventories of refinery grade propylene, propane and polymer grade propylene owned by such affiliates for approximately $239 million (subject to certain post-closing adjustments). The primary asset purchased was a 66.67% interest in a 41 MBPD (27.3 MBPD, net) polymer grade propylene fractionation facility located in Mont Belvieu, Texas (deemed "Mont Belvieu III"). When combined with our existing Mont Belvieu I and II facilities, we own 58.3 MBPD of net processing capacity at this key industry hub.

Principal propylene fractionation facilities

Mont Belvieu I and II. We operate two polymer grade propylene fractionation facilities (Mont Belvieu I and II) in Mont Belvieu, Texas having a combined capacity of 31 MBPD. We own a 54.6% interest in Mont Belvieu I and all of Mont Belvieu II. We lease the remaining 45.4% interest in Mont Belvieu I from a customer, Basell.

Results of operation for our polymer grade propylene plants are generally dependent upon toll processing arrangements and propylene merchant activities. Under toll processing arrangements, we are paid fees based on throughput of refinery grade propylene used to produce polymer grade propylene. Our largest toll processing customers in 2001 were Huntsman and Equistar. In our propylene merchant business, we have several long-term polymer grade propylene sales agreements, the largest of which is with Basell. In order to meet our merchant obligations, we have entered into several long-term agreements to purchase refinery grade propylene. In order to limit the exposure to price risk in the merchant side of this business, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products. During 2001, 10 MBPD of our net polymer grade propylene production was associated with toll processing operations with the balance attributable to merchant activities.

We are able to unload barges carrying refinery grade propylene using our import terminal located on the Houston Ship Channel. We are also able to receive supplies of refinery grade propylene through our Mont Belvieu truck and rail unloading facility and from refineries and other producers connected to our HSC pipeline system. In turn, polymer grade propylene is transported to customers by truck or pipeline.

Beginning in February 2002, we are also able to load and unload volumes of polymer grade propylene as a result of our 50% investment in Olefins Terminal Corporation located in Seabrook, Texas. For more information regarding this facility, see page 13.

BRPC. We operate and own a 30% interest in BRPC, which owns a 23 MBPD chemical grade propylene production facility located near Baton Rouge, Louisiana. This unit, located across the Mississippi River from Exxon Mobil's refinery and chemical plant, fractionates refinery grade propylene produced by Exxon Mobil into chemical grade propylene for a toll processing fee. Results of operation of BRPC are dependent upon the volume of refinery grade propylene processed and the level of fees charged to Exxon Mobil.

Pipelines

Our Pipelines segment owns or has interests in approximately 4,800 miles of natural gas and liquids transportation and distribution pipelines located primarily along the central and western Gulf Coast of the U.S. This segment also includes our storage and import/export terminal services.

Natural gas pipelines

The Company entered the natural gas pipeline business in 2001. During the last year, we invested $338 million in such businesses including $226 million paid to Shell for the purchase of Acadian Gas (an onshore Louisiana system) and a combined $112 million paid to El Paso for equity interests in four Gulf of Mexico natural gas pipelines (primarily Gulf of Mexico offshore Louisiana systems). The acquisition of these businesses represent strategic investments for the Company. We believe that these assets have attractive growth attributes given the expected long-term increase in natural gas demand for industrial and power generation uses. In addition, these assets extend our midstream energy service relationship with long-term NGL customers (producers, petrochemical suppliers and refineries) and provide us with opportunities to generate additional fee-based cash flows.

The following table summarizes our natural gas pipeline assets and ownership interests at December 31, 2001:

Natural Gas Pipelines	Length In Miles	Our Ownership Interest
Acadian Gas	1,015	100%
Stingray	379	50%
Manta Ray and Nautilus	336	25.67%
Evangeline	27	49.5%
Nemo	24	33.92%
Total	1,781	

Our natural gas pipeline systems provide for the gathering, transmission and storage of natural gas from both onshore and offshore Louisiana developments. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas at other points throughout the system. Generally, natural gas pipeline transportation agreements generate revenue for these systems based on a transportation fee per unit of volume (generally in MMBtus) transported. Natural gas pipelines (such as our Acadian Gas system) may also gather and purchase natural gas from producers and suppliers and resell such natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers. As such, our Acadian Gas operation could be exposed to commodity price risk to the extent it takes title to natural gas volumes through certain of its contracts. Our Gulf of Mexico systems generally do not take title to the natural gas that they transport; the shipper retains title and the associated commodity price risk.

Within their market area, our onshore systems compete with other natural gas pipeline companies on the basis of price (in terms of transportation rates and/or natural gas selling prices), service and flexibility. Our competitive position within the onshore market is positively affected by our longstanding relationships with customers and the limited number of delivery pipelines connected (or capable of being connected) to the customers we serve. In addition, our financial flexibility gives our customers confidence in our ability to deliver on contracts. Conversely, we are exposed to concentrations of customers in certain market segments (such as the chemical/refining industry in south Louisiana) in which the business cycle could affect their creditworthiness and/or ability to continue business with us. Our Gulf of Mexico offshore pipeline systems compete primarily on the basis of transportation rates and service. These pipelines are strategically situated to gather a substantial volume of the natural gas production in the offshore Louisiana area from both continental shelf and deepwater developments.

Our onshore and offshore systems are affected by natural gas exploration and production activities. If these exploration and production activities decline as a result of a weakened domestic economy or due to natural depletion of the oil and gas fields they are connected to, then throughput volumes on these pipelines will decline, thereby affecting our earnings from these investments. We actively seek to offset the loss of volumes due to natural depletion by seeking connections to new customers and fields.

In light of the complex, interconnected nature of the pipeline networks and the varying diameter of pipe used and pressure employed, the utilization of these assets is measured in MMBtu/d of natural gas transported.

Principal natural gas pipelines

Acadian Gas and Evangeline. In April 2001, we acquired Acadian Gas from Shell for approximately $226 million using proceeds from the issuance of our $450 million Senior Notes B. Acadian Gas is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. Its assets are comprised of the 438-mile Acadian and 577-mile Cypress natural gas pipelines and a leased natural gas storage facility. Acadian Gas owns a 49.5% equity interest in Evangeline, which owns a 27-mile natural gas pipeline. We operate the Acadian Gas and Evangeline systems.

Overall, the Acadian Gas and Evangeline systems are comprised of 1,042 miles of pipeline. During 2001, these systems had an average throughput of 783,485 MMBtu/d of natural gas during the period in which we owned or had an interest in these assets, on a net basis.

The Acadian Gas and Evangeline systems link supplies of natural gas from Gulf of Mexico production (through connections with offshore pipelines) and various onshore developments to industrial, electric and local gas distribution customers primarily located in Louisiana. In addition, these systems have interconnects with twelve interstate and four intrastate pipelines and a bi-directional interconnect with the U.S. natural gas marketplace at the Henry Hub.

Stingray. In January 2001, we purchased a 50% interest in the Stingray natural gas pipeline system and a related natural gas dehydration facility from El Paso. We own our interest in these assets through our 50% equity investment in Starfish, a joint venture with Shell. The Stingray system is a 379-mile, FERC-regulated natural gas pipeline system that transports natural gas and condensate from certain production areas located in the Gulf of Mexico offshore Louisiana to onshore transmission systems located in south Louisiana. The natural gas dehydration facility is connected to the onshore terminus of the Stingray system in south Louisiana. During 2001, this system transported 300,000 MMBtu/d of natural gas, on a net basis. Shell is the operator of these systems and owns the remaining equity interest in Starfish.

Manta Ray, Nautilus and Nemo. In conjunction with our purchase of the Stingray interest, we also acquired from El Paso a 25.67% interest in the Manta Ray and Nautilus natural gas pipeline systems located in the Gulf of Mexico offshore Louisiana. The Manta Ray system comprises approximately 235 miles of unregulated pipelines and related equipment and the Nautilus system comprises approximately 101 miles of FERC-regulated pipelines. Our ownership of the Manta Ray and Nautilus systems is through our unconsolidated affiliate, Neptune. We also purchased from El Paso a 33.92% interest in the 24-mile Nemo natural gas pipeline, which became operational in August 2001.

Like Stingray, Shell is the operator of the Manta Ray and Nemo systems. Shell is the administrative agent for Nautilus. Shell and Marathon are our co-owners in Neptune and Shell owns the remaining interest in Nemo. These systems transported a combined 265,914 MMBtu/d of natural gas during 2001, as measured on a net basis.

Liquids pipelines

Our liquids pipelines transport mixed NGLs and hydrocarbons to NGL fractionation plants, distribute purity NGL products and propylene to petrochemical plants and refineries and deliver propane to customers along the Dixie pipeline. Our pipelines provide transportation services to customers on a fee basis. As such, the results of operation for this business are generally dependant upon the volume of product transported and the level of fees charged to customers (which include our merchant businesses). Taken as a whole, this business area does not exhibit a significant degree of seasonality; however, volumes on the Dixie pipeline are higher in the November through March timeframe due to increased use of propane for heating in the southeastern United States. In addition, volumes on the Lou-Tex NGL pipeline will generally increase during the April through September period due to gasoline blending considerations at refineries.

The following table summarizes our principal liquids pipeline transportation and distribution networks at December 31, 2001:

Liquids Pipelines	Length In Miles	Our Ownership Interest
Dixie	1,301	19.88%
Louisiana Pipeline System	536	100%
Lou-Tex Propylene	291	100%
Lou-Tex NGL	206	100%
HSC	175	100%
Tri-States	169	33.33%
Lake Charles/Bayport	164	50%
Chunchula	117	100%
Belle Rose	48	41.67%
Wilprise	30	37.35%
Total liquids pipelines	3,037	

The maximum number of barrels that these systems can transport per day depends upon the operating balance achieved at a given time between various segments of the system. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacity of the systems cannot be stated. As shown in the following table, utilization is measured in terms of throughput (in MBPD, on a net basis).

	For Year Ended December 31,		
Liquids Pipelines	2001	2000	1999
Dixie	26	14	14
Louisiana Pipeline System	138	115	74
Lou-Tex Propylene	27	23	
Lou-Tex NGL	29	30	
HSC	133	106	99
Tri-States, Wilprise and Belle Rose	36	42	41
Lake Charles/Bayport	6	5	5
Chunchula	5	6	7
Total liquids pipelines	400	341	240

In the markets we serve, we compete with a number of intrastate and interstate liquids pipeline companies (including those affiliated with major oil and gas companies) and barge and truck fleet operators. In general, our liquids pipelines compete with these entities in terms of transportation rates and service. We believe that our pipeline systems are cost effective and allow for significant flexibility in rendering transportation services for our customers.

Principal liquids pipelines

Dixie. The Dixie pipeline is a 1,301-mile propane pipeline which transports propane supplies from Mont Belvieu, Texas and Louisiana to markets in the southeastern United States. We own a 19.88% interest in Dixie. An affiliate of Phillips operates the system.

Louisiana Pipeline System. The Louisiana Pipeline System is a 536-mile network of nine NGL pipelines located in Louisiana. This system is used to transport propane, butanes and natural gasoline and serves a variety of customers including major refineries and petrochemical companies along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our gas processing plants and other facilities located in Louisiana. In general, we own and operate these pipelines.

Lou-Tex Propylene. The Lou-Tex Propylene pipeline system consists of a 263-mile pipeline used to transport propylene from Sorrento, Louisiana to Mont Belvieu, Texas. Currently, this system is used to transport chemical grade propylene for third parties from production facilities in Louisiana to customers in Texas. This system also includes storage facilities and a 28-mile NGL pipeline. We own and operate this system.

Lou-Tex NGL. The Lou-Tex NGL pipeline system consists of a 206-mile NGL pipeline used to provide transportation services for NGL products and refinery grade propylene between the Louisiana and Texas markets. We also use this pipeline to transport mixed NGLs from our Louisiana gas processing plants to our Mont Belvieu NGL fractionation facility. We own and operate this pipeline system.

HSC. The HSC pipeline system is a collection of NGL and petrochemical pipelines aggregating 175 miles in length extending from our Houston Ship Channel import/export terminal facility to Mont Belvieu, Texas. This pipeline is used to deliver products to third-party petrochemical plants and refineries as well as to deliver feedstocks to our Mont Belvieu facilities. This system is also used to transport MTBE produced by BEF to delivery locations along the Houston Ship Channel. We own and operate this pipeline system.

Tri-States, Belle Rose and Wilprise. We participate in pipeline joint ventures which supply mixed NGLs to the BRF and Promix NGL fractionators. We own a 33.33% interest in Tri-States, which owns a 169-mile NGL pipeline that extends from Mobile Bay, Alabama to near Kenner, Louisiana. In addition, we own a 41.67% interest in and operate Belle Rose, which owns a 48-mile NGL pipeline that extends from near Kenner, Louisiana to Promix. Lastly, we own a 37.35% interest in Wilprise, which owns a 30-mile NGL pipeline that extends from near Kenner, Louisiana to Sorrento, Louisiana. An affiliate of Williams operates the Tri-States and Wilprise systems.

Lake Charles/Bayport. Our Lake Charles/Bayport system is a 164-mile propylene pipeline used to distribute polymer grade propylene from Mont Belvieu to Basell's polypropylene plants in Lake Charles, Louisiana and Bayport, Texas and to Aristech's facility in La Porte, Texas. A segment of the pipeline is jointly owned by us and Basell, and another segment is leased from Exxon Mobil.

Chunchula. The Chunchula pipeline system is a 117-mile NGL pipeline extending from the Alabama-Florida border to our storage and NGL fractionation facilities in Petal, Mississippi for further distribution. We own and operate this system.

Storage and import/export terminal

Storage. Our hydrocarbon storage facilities and NGL import/export terminal are integral parts of our pipeline operations. In general, our storage wells are used to store NGLs and petrochemical products for customers and ourselves. The profitability of storage operations is primarily dependent upon the volume of material stored and the level of fees charged. In January 2002, we completed the purchase of Diamond-Koch's Mont Belvieu storage assets for $129 million. These facilities include 30 storage wells with a useable capacity of 68 MMBbls and allow for the storage of mixed NGLs, ethane, propane, butanes, natural gasoline and olefins (such as ethylene), polymer grade propylene, chemical grade propylene and refinery grade propylene. With the addition of the former Diamond-Koch facilities, we own and operate 95 MMBbls of storage capacity at Mont Belvieu.

We also own storage facilities located at Breaux Bridge, Napoleonville, Sorrento and Venice, Louisiana having a gross capacity of 33 MMBbls and a net capacity of 14.8 MMBbls. Our Mississippi storage assets are comprised of facilities located at or near Petal and Hattiesburg having a gross capacity of 12 MMBbls and a net capacity of 9.5 MMBbls. Of the facilities located in Louisiana and Mississippi, we operate those located in Breaux Bridge, Louisiana and Petal, Mississippi. Affiliates of Koch, Dynegy and Shell operate the remaining facilities.

The following table summarizes our storage assets by state at March 1, 2002:

Storage Assets	Gross Capacity, MMBbls	Net Capacity, MMBbls
Texas	95	95
Louisiana	33	14.8
Mississippi	12	9.5
Total	140	119.3

When used in conjunction with our processing operations, these wells allow us to mix various batches of feedstock and maintain a sufficient supply and stable composition of feedstock to our processing facilities. At times, we provide some of our processing customers with short-term storage services (typically 30 days or less) at nominal amounts when they cannot take immediate delivery of products. Intersegment revenues for the Pipelines segment include those fees charged to our various merchant businesses for use of the storage facilities.

We are primarily in the merchant storage business with our focus being to attract customers to store products in our wells for a fee. Our competitors in this area are other merchant storage and pipeline companies such as Texas Eastern Pipeline Partners Company ("TEPPCO"), Dynegy and Equistar. In addition, major oil and gas companies such as Exxon Mobil and Phillips occasionally use their proprietary storage assets in a merchant role thereby entering into competition with us and other merchant providers. Our Mont Belvieu facilities (including those recently acquired from Diamond-Koch) represent the largest merchant storage facilities in the world for NGLs and olefins. We compete with other service providers primarily in terms of the fees charged, pipeline connections and dependability. We believe that due to the integrated nature of our operations, our storage customers have access to a competitively priced, flexible and dependable network of assets.

Import/Export terminal. We lease and operate an NGL import facility located on the Houston Ship Channel that enables NGL tankers to be offloaded at their maximum unloading rate of 10,000 barrels per hour, thus minimizing laytime and increasing the number of vessels that can be offloaded. This facility is primarily used to offload volumes bound for our facilities in Mont Belvieu. Typically, our import activity exhibits little seasonality; however, throughput can be positively affected when domestic demand for NGLs exceeds supply making it profitable to transport NGLs by barge or ship from overseas locations or other domestic ports. For example, imports of normal butane destined for our isomerization plants increased significantly during the second quarter of 2001 due to demand for isobutane. In addition, we own a 50% interest in EPIK, which owns NGL export facilities at the same terminal including an NGL product chiller and related equipment used for loading refrigerated marine tankers. The export terminal can load vessels of refrigerated propane and butane at rates up to 5,000 barrels per hour. Traditionally, EPIK's export volumes are higher during the winter months due to increased propane exports. The profitability of import and export activities primarily depends upon the quantities loaded and offloaded and the throughput fees associated with each activity.

The following table shows volumes loaded and offloaded through our import/export terminal over the last three years (in MBPD, on a net basis).

Facility	For Year Ended December 31, 2001	2000	1999
NGL import facility	45	9	14
EPIK	8	17	10
Total imports and exports	53	26	24

When compared to 2000, export activity declined as strong domestic pricing for products reduced the economic need to export. Normal butane imports were higher in 2001 due to increased isobutane production.

Our NGL import and EPIK's NGL export facility have a small number of competitors, primarily Dynegy and Dow. These operations compete primarily in terms of service (i.e., the ability to quickly load or offload vessels). Our competitive position is enhanced because our extensive storage and pipeline assets at Mont Belvieu allow us to load and offload ships very efficiently.

In February 2002, we acquired a 50% interest in Olefins Terminal Corporation ("OTC"). Our interest in OTC was acquired in connection with the purchase of the Mont Belvieu III propylene fractionation facility from Diamond-Koch. OTC owns a dock facility located in Seabrook, Texas for the receipt, storage, handling and redelivery of polymer grade propylene.

Processing

The Processing segment consists of our natural gas processing business and related merchant activities. At the core of our natural gas processing business are twelve processing plants located on the Louisiana and Mississippi Gulf Coast with a gross natural gas processing capacity of 11.61 Bcf/d (3.25 Bcf/d on a net basis). Our net share of the NGL production from these plants, in addition to NGLs we purchase on a merchant basis and a portion of the production from our Mont Belvieu isomerization facilities, support the merchant activities included in this operating segment.

The majority of the operating margin earned by our natural gas processing plants is based on the relative economic value of the mixed NGLs extracted by the gas plants as compared to the costs of extracting the mixed NGLs (principally that of natural gas as a feedstock and as a fuel, plus plant operating expenses). Natural gas processing arrangements where the processor (i.e., the Company) takes title to the NGLs extracted from the natural gas stream are defined as "keepwhole contracts". The processor reimburses producers (e.g., Shell and others) for the market value of the energy extracted based upon the Btus (a measure of heat value) consumed from the natural gas stream in the form of fuel and mixed NGLs, multiplied by the market value of natural gas. The processor derives a profit margin to the extent the market value of the NGLs extracted exceeds the costs of extraction.

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 the Gulf of Mexico within the state and federal waters off Texas, Louisiana, Mississippi, Alabama and Florida (on a keepwhole basis). This includes natural gas production from deepwater developments. This is a life of lease dedication which may extend the agreement well beyond twenty years. Shell is the largest oil and gas producer and holds one of the largest lease positions in the deepwater Gulf of Mexico. Generally, this contract has the following rights and obligations:

- the exclusive right to process any and all of Shell's Gulf of Mexico natural gas production from existing and future dedicated leases (i.e., life of lease dedication); 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 deliver to Shell the natural gas stream after the mixed NGL stream is extracted.

We believe that natural gas and its associated NGL production from the Gulf of Mexico will significantly increase in the coming years as a result of advances in seismic and deepwater development technologies and continued capital spending for exploration and production by major oil companies.

Several deepwater Gulf of Mexico developments began production during 2001. These include Shell's Ursa, Brutus, Oregano, Crosby, Einset and Serrano developments. As a result of these new streams of rich natural gas, in the fourth quarter of 2001, we set a record for equity NGL production at 80 MBPD. Had NGL demand supported full extraction, our equity NGL production during the fourth quarter would have been in excess of 90 MBPD.

North American natural gas demand increased by 9 Bcf/d from 1980 to 2001, from 63 Bcf/d to approximately 72 Bcf/d. Because of its environmental and economic advantages, natural gas has become the preferred fuel for new power generation facilities. By 2005, industry expectations are that natural gas demand will increase by an additional 9 Bcf/d to 81 Bcf/d. By 2010 and 2015, natural gas demand is expected to increase to 93 Bcf/d and 102 Bcf/d, respectively. To supply this demand, natural gas producers are challenged to find new sources of gas.

The five key frontier gas supply areas that are expected to support the growing demand for natural gas are Alaska, the Mackenzie Delta in Northwest Canada, imports of liquefied natural gas ("LNG"), the deepwater Gulf of Mexico and the Rocky Mountains. At present, the industry expects the Alaska and Mackenzie Delta natural gas volumes will take eight to ten years to bring to market in light of regulatory and environmental permitting, the execution of customer and right-of-way agreements, pipeline construction requirements and other factors. In the case of LNG, currently there are only four LNG import terminals in the United States. Of the eleven terminals proposed to date, most would commence operations in 2005 or later. In addition, a new fleet of LNG tankers must be built to facilitate a major increase in LNG imports.

In the near term, the most viable sources of new natural gas supply are the deepwater Gulf of Mexico and the Rocky Mountains. Production from deepwater Gulf of Mexico areas is expected to increase from 2.9 Bcf/d in 2000 to approximately 5.7 Bcf/d by 2010 and 8.2 Bcf/d by 2015. New supplies from deepwater Gulf of Mexico are expected to supply 20% of natural gas demand growth in the United States by 2010 and 25% by 2015. The deepwater Gulf of Mexico developments are even more strategic to the United States in terms of crude oil and condensate production. In 2000, the Gulf of Mexico accounted for 24% of domestic crude oil and condensate production. It is forecasted that by 2005, 37% of domestic crude oil and condensate production will originate from the Gulf of Mexico (primarily from deepwater developments)and by 2010, this percentage is expected to grow to 43% total domestic production.

Since natural gas from deepwater developments is primarily associated with the production of crude oil, it usually contains a higher content of NGLs (in quantities in excess of four gallons per Mcf of gas, referred to as "rich" natural gas) than that of natural gas produced from continental shelf and land-based production, which generally contains one to one and a half gallons of NGLs per Mcf of gas. To meet the quality specifications of interstate pipelines and end-use consumers, deepwater natural gas must be processed to remove the NGLs or at least the heaviest NGL components. On an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemicals and motor gasoline than their value in natural gas.

Our natural gas processing facilities are primarily straddle plants which are situated on mainline natural gas pipelines which bring unprocessed Gulf of Mexico natural gas production onshore. Straddle plants allow us to extract NGLs from a raw natural gas stream when the market value of the NGLs exceeds the cost (principally that of natural gas as a feedstock and as a fuel) of extracting the mixed NGLs. After extraction, we transport the mixed NGLs to a centralized facility for fractionation into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used by our merchant business to meet contractual requirements or sold on spot and forward markets.

The following table lists our gas processing plants, their processing capacities and corresponding ownership interest:

Gas Processing Facility	Location	Gross Gas Processing Capacity (Bcf/d)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d)
Yscloskey	Louisiana	1.85	28.2%	0.52
Calumet	Louisiana	1.60	35.4%	0.57
North Terrebonne	Louisiana	1.30	33.7%	0.44
Venice	Louisiana	1.30	13.1%	0.17
Toca	Louisiana	1.10	57.1%	0.63
Pascagoula	Mississippi	1.00	40%	0.40
Sea Robin	Louisiana	0.95	15.5%	0.15
Blue Water	Louisiana	0.95	7.4%	0.07
Iowa	Louisiana	0.50	2%	0.01
Patterson II	Louisiana	0.60	2%	0.01
Neptune	Louisiana	0.30	66%	0.20
Burns Point	Louisiana	0.16	50%	0.08
	Total	11.61		3.25

The natural gas throughput capacities of the plants are based on practical limitations. Our utilization of these gas plants depends upon general economic and operating conditions and is generally measured in terms of equity NGL production. Equity NGL production is defined as the volume of NGLs extracted by the gas plants to which we take title under the terms of processing agreements or as a result of our plant ownership interests. Equity NGL production can be adversely affected by high natural gas costs and/or low purity NGL product prices. Our equity NGL production averaged 63 MBPD during 2001, 72 MBPD during 2000 and 67 MBPD during 1999.

As noted previously, we take title to a portion of the mixed NGLs that are extracted by the gas plants. Once this mixed NGL volume is fractionated into purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline), we use them to meet contractual requirements or sell them on spot and forward markets as part of our overall merchant business activities. In our isomerization merchant activities, we are party to a number of isobutane sales contracts. In order to fulfill our obligations under these sales contracts, we can purchase isobutane on the spot market for resale, sell our isobutane in inventory or pay our isomerization business (which is part of the Fractionation segment) a toll processing fee to process our inventories of imported or domestically-sourced normal and mixed butanes into isobutane.

Since 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. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. We attempt to mitigate these risks through the use of commodity financial instruments. For a general discussion regarding our commodity financial instruments, see Item 7A of this Form 10-K.

Some of our exposure to commodity price risk is mitigated because natural gas having a high content of NGLs must be processed in order to meet pipeline quality specifications and to be suitable for ultimate consumption. To the extent that natural gas is not processed and does not meet pipeline quality specifications, this unprocessed natural gas and its associated crude oil production may be subject to being shut-in (i.e., to not being processed and made marketable). Therefore, producers are motivated to reach contractual arrangements that are acceptable to gas processors in order for gas processing services to be available on a continuous basis (e.g., through natural gas cost reductions and other economic incentives to gas processors).

The consumption of NGL products in the United States can be separated into four distinct markets. Petrochemical production provides the largest end-use market, followed by motor gasoline production, residential and commercial heating and agricultural uses. There are other hydrocarbon alternatives, primarily refined petroleum products, which can be substituted for NGL products in most end uses. In some cases, such as residential and commercial heating, a substitution of other hydrocarbon products for NGL products would require a significant expense or delay, but for other uses, such as the production of motor gasoline, ethylene, industrial fuels and petrochemical feedstocks, such a substitution can be readily made without significant delay or expense.

Because certain NGL products compete with other refined petroleum products in the fuel and petrochemical feedstock markets, NGL product prices are set by or in competition with refined petroleum products. Increased production and importation of NGLs and NGL products in the United States may decrease NGL product prices in relation to refined petroleum alternatives and thereby increase consumption of NGL products as NGL products are substituted for other more expensive refined petroleum products. Conversely, a decrease in the production and importation of NGLs and NGL products could increase NGL product prices in relation to refined petroleum product prices and thereby decrease consumption of NGLs. However, because of the relationship of crude oil and natural gas production to NGL production, we believe any imbalance in the prices of NGLs and NGL products and alternative products would be temporary. Our gas processing business does not exhibit a high degree of seasonality.

Our gas processing business and related merchant activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each of our competitors has varying levels of financial and personnel resources and competition generally revolves around price, service and location issues. Our integrated system affords us flexibility in meeting our customers' needs. While many companies participate in the gas processing business, few have a presence in significant downstream activities such as NGL fractionation and transportation, import/export services and merchant activities as we do. Our competitive or leading strategic position and sizeable presence in these downstream businesses allows us to extract incremental value while offering our customers enhanced services, including comprehensive service packages.

Our merchant activities utilize a fleet of approximately 625 railcars, the majority of which are under short and long-term leases. The railcars are used to deliver feedstocks to our facilities and to transport NGL products throughout the United States. We have rail loading/unloading facilities at Mont Belvieu, Texas, Breaux Bridge, Louisiana and Petal, Mississippi. These facilities service the Company's as well as customers' rail shipments. This segment also includes our 13.1% investment in VESCO. VESCO owns an integrated complex comprised of the Venice gas processing plant, a fractionation facility, storage assets and gas gathering pipelines in Louisiana.

Octane Enhancement

The Octane Enhancement segment consists of our 33.33% interest in BEF, which owns a facility that produces motor gasoline additives to enhance octane. Our partners in BEF are affiliates of Sun and Devon Energy. The BEF facility currently produces MTBE and is located within our Mont Belvieu complex. The gross capacity of the MTBE facility is approximately 15 MBPD with a net capacity of 5 MBPD. For the years 2001, 2000 and 1999, net production averaged 5 MBPD. An affiliate, EPCO, operates the facility.

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 the 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 would reduce the demand for MTBE and could have a negative impact on our operations. Although oxygenated fuel requirements can be satisfied by using other products such as ethanol, MTBE has gained the broadest acceptance due to its ready availability and history of acceptance by refiners. Additionally, motor gasoline containing MTBE can be transported through pipelines, which is a significant competitive advantage over alcohol blends such as ethanol.

MTBE demand is linked to motor gasoline requirements in certain urban areas of the United States designated as carbon monoxide and ozone non-attainment areas by the Clean Air Act Amendments of 1990 and the California oxygenated motor gasoline program. Motor gasoline demand in turn is affected by many factors, including the price of motor gasoline (which is generally dependent upon crude oil prices) and overall economic conditions. BEF has a ten-year off-take agreement with Sun under which Sun is obligated to purchase all of BEF's MTBE production through September 2004. Beginning in June 2000 and for the remaining term of this agreement, Sun is required to purchase all of the plant's MTBE production at spot-market related prices. Sun uses this MTBE primarily to satisfy the gasoline blending requirements of its markets located in the eastern United States.

Historically, the spot price for MTBE has been at a modest premium to gasoline blend values. BEF is exposed to commodity price risk due to the market-related pricing provisions of the Sun off-take agreement. In general, MTBE prices are stronger during the April to September period of each year, which corresponds with the summer driving season. Future MTBE demand is highly dependent upon environmental regulation, federal legislation and the actions of individual states (see Recent Regulatory Developments below).

Each owner of BEF is responsible for supplying one-third of the facility's isobutane feedstock requirements through June 2004. We, along with the other two co-owners, use high purity isobutane produced at our Mont Belvieu facilities to meet this obligation. The methanol feedstock used by BEF is purchased from third-parties under long-term contracts and transported to Mont Belvieu using our HSC pipeline system. Lastly, BEF's MTBE production is transported to a location on the Houston Ship Channel for delivery to Sun using our HSC pipeline system.

The MTBE market has a number of producers, including a number of refiners who produce MTBE for internal consumption in the manufacture of reformulated motor gasoline. In general, MTBE producers compete in terms of price and production (in terms of economies of scale and quality of product). While the Sun contract is in effect, BEF is not directly exposed to its competition, although it is affected by market pricing through the Sun off-take agreement. The world-class scale of the BEF facility, combined with the technological advances incorporated into its construction and maintenance, make it one of the most efficient domestic MTBE plants in operation.

Recent Regulatory Developments. 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. For additional information regarding the impact of environmental regulation on BEF, see "Impact of the Clean Air Act's oxygenated fuels programs on our BEF investment" on page 22.

Alternative uses of the BEF facility. In light of these regulatory developments, the owners of BEF have been formulating a contingency plan for use of the BEF facility if MTBE were banned or significantly curtailed. Management is exploring possible conversion of the BEF facility from MTBE production to alkylate production. 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 motor gasoline and that alkylate would be an attractive substitute. Depending upon the type of alkylate process chosen and the level of alkylate production desired, the cost to convert the facility from MTBE production to alkylate production would range from $20 million to $90 million, with our share of these costs ranging from $6.7 million to $30 million.

Other

This operating segment is primarily comprised of fee-based marketing services. For a small number of clients, we perform NGL marketing services for which we charge a commission. The clients we serve are primarily located in the states of Washington, California and Illinois. We utilize the resources of our merchant businesses to perform these services. Commissions are generally based on either a percentage of the final sales price negotiated on behalf of the client or on a fixed-fee per gallon basis. Our fee-based marketing services handle approximately 23 MBPD of various NGL products with the period of highest activity occurring during the summer months. The principal elements of competition in this business are price and quality of service. This segment also includes other engineering services, construction equipment rentals and computer network services that support other operations and business activities.

Employees

We do not have any employees. An affiliate, EPCO, employs all the persons necessary for the operation of our business. At December 31, 2001, EPCO employed 898 employees involved in the management and operations of our business, none of whom were members of a union. We reimburse EPCO for the services of certain of its employees under a long-term services agreement (see "EPCO Agreement" on page 59).

Major Customers

Our revenues are derived from a wide customer base. Our largest customer, Shell and its affiliates, accounted for 10.5% and 9.5% of consolidated revenues in 2001 and 2000, respectively. Approximately 80% of our revenues from Shell and its affiliates are attributable to sales of NGL products which are recorded in our Processing segment. For additional information regarding significant customers of the last three fiscal years, see Note 15 of the Notes to the Consolidated Financial Statements.

Regulation and Environmental Matters

Regulation of our interstate common carrier liquids pipelines

Our Chunchula, Lou-Tex Propylene, Lou-Tex NGL, Lake Charles/Bayport and Dixie pipelines along with certain pipelines of the Louisiana Pipeline System are interstate common carrier liquids pipelines subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the October 1, 1977 version of the Interstate Commerce Act ("ICA").

As interstate common carriers, these pipelines provide service to any shipper who requests transportation services, provided that products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. The ICA requires us to maintain tariffs on file with the FERC that set forth the rates we charge for providing transportation services on our interstate common carrier pipelines as well as the rules and regulations governing these services.

The ICA gives the FERC authority to regulate the rates we charge for service on the interstate common carrier pipelines. The ICA requires, among other things, that such rates be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge proposed new or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act of 1992 ("Energy Policy Act"). The Energy Policy Act deemed petroleum pipeline rates that were in effect during any of the twelve months preceding enactment that had not been subject to complaint, protest or investigation to be just and reasonable under the ICA (i.e., "grandfathered"). The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party would have to show that it was previously contractually barred from challenging the rates or that the economic circumstances or the nature of the service underlying the rate had substantially changed or that the rate was unduly discriminatory or preferential. These grandfathering provisions and the circumstances under which they may be challenged have received only limited attention from the FERC, causing a degree of uncertainty as to their application and scope. The Chunchula and Lake Charles/Bayport pipeline and portions of the Louisiana Pipeline System are covered by the grandfathered provisions of the Energy Policy Act.

The Energy Policy Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines, and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561, which, among other things, adopted a new indexing rate methodology for petroleum pipelines. Under the new regulations, which became effective January 1, 1995, petroleum pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made within the ceiling levels will be subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling. Under Order No. 561, a pipeline must as a general rule utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances.

We believe that the rates charged for transportation services on the interstate pipelines we own or have an interest in are just and reasonable under the ICA. As discussed above, however, because of the uncertainty related to the application of the Energy Policy Act's grandfathering provisions as well as the novelty and uncertainty related to the FERC's new indexing methodology, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

In a 1995 decision involving Lakehead Pipe Line Company ("Lakehead"), an unrelated pipeline limited partnership, the FERC partially disallowed the inclusion of income taxes in that partnership's cost of service. Subsequent appeals of these rulings were resolved by settlement and were not adjudicated. In another FERC proceeding involving SFPP, L.P. ("SFPP"), another unrelated pipeline limited partnership, the FERC held that the limited partnership may not claim an income tax allowance for income attributable to non-corporate partners, both individuals and other entities. SFPP and other parties to the proceeding have appealed the FERC's order to the U.S. Court of Appeals for the District of Columbia Circuit, which is holding the appeals in abeyance while the FERC resolves requests for rehearing of its orders. The effect of the FERC's policy stated in the Lakehead proceeding (and the results of the ongoing SFPP litigation regarding that policy) on us is uncertain. Our rates are set using the indexing method and/or have been grandfathered. It is possible that a party might challenge our grandfathered rates (set when the assets were held by our corporate predecessor) on the basis that our master limited partnership structure constitutes a substantial change in circumstances, potentially lifting the grandfathering protection, and further a party might contend that, in light of the Lakehead and related-rulings and the creation of our master limited partnership structure, our rates are not just and reasonable. While it is not possible to predict the likelihood that such challenges would succeed at the FERC, if such challenges were to be raised and succeed, application of the Lakehead and related-rulings would reduce our permissible income tax allowance in any cost-of-service based rate, to the extent income tax is attributed to partnership interests held by individual partners rather than corporations.

Regulation of our interstate natural gas pipelines

The Stingray and Nautilus natural gas pipeline systems are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC-approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. In addition, the FERC's authority over natural gas companies that provide natural gas pipeline transportation or storage services in interstate commerce includes the certification and construction of new facilities; the extension or abandonment of services and facilities; the maintenance of accounts and records; the acquisition and disposition of facilities; the initiation and discontinuation of services; and various other matters. As noted above, the Stingray and Nautilus systems have tariffs established through FERC filings that have a variety of terms and conditions, each of which affect the operations of each system and its ability to recover fees for the services it provides. Generally, changes to these fees or terms can only be implemented upon approval by the FERC.

Commencing in 1992, the FERC issued Order No. 636 and subsequent orders (collectively, "Order No. 636"), which require interstate pipelines to provide transportation and storage services separate, or "unbundled," from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open-access transportation and storage services on a basis that is equal for all shippers. The FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although the FERC continues to review and modify its open access regulations.

In 2000, the FERC issued Order No. 637 and subsequent orders (collectively, "Order No. 637"), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 are pending judicial review. We cannot predict whether and to what extent FERC's market reforms will survive judicial review and, if so, whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that the operations of Nautilus and Stingray (or our other pipeline and storage operations which are indirectly affected by the extent and nature of FERC's jurisdiction over activities in interstate commerce) will be affected in any materially different way than other companies with whom we compete.

In addition to its jurisdiction over Stingray and Nautilus under the Natural Gas Act and the Natural Gas Policy Act, the FERC also has jurisdiction over Stingray and Nautilus, as well as Manta Ray, under the Outer Continental Shelf Lands Act ("OCSLA"). The OCSLA requires that all pipelines operating on or across the outer continental shelf provide open-access, non-discriminatory transportation service on their systems. Commencing in April 2000, FERC issued Order Nos. 639 and 639-A (collectively, "Order No. 639"), which required "gas service providers" operating on the outer continental shelf to make public their rates, terms and conditions of service. The purpose of Order No. 639 was to provide regulators and other interested parties with sufficient information to detect and remedy discriminatory conduct by such service providers. In a recent decision, the U.S. District Court for the District of Columbia permanently enjoined the FERC from enforcing Order No. 639, on the basis that the FERC did not possess the requisite rulemaking authority under the OCSLA for issuing Order No. 639. FERC's appeal of the court's decision is pending in the U.S. Court of Appeals for the District of Columbia Circuit. We cannot predict the outcome of this appeal, nor can we predict what further action FERC will take with respect to this matter.

On September 27, 2001, FERC issued a Notice of Proposed Rulemaking in Docket No. RM01-10. The proposed rules would expand FERC's current standards of conduct to include a regulated transmission provider and all of its energy affiliates. It is not known whether FERC will issue a final rule in this docket and, if it does, whether we could, as a result, incur increased costs and difficulty in our operations.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Regulation of our intrastate common carrier liquids and natural gas pipelines

Certain portions of the Louisiana Pipeline System and all of the Acadian Gas natural gas pipeline system are intrastate common carrier pipelines that are subject to various Louisiana state laws and regulations that affect the rates we charge and the terms of service.

Other state and local regulation of our operations

Our business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters.

Potential impact of regulation on our electrical cogeneration assets

We cogenerate electricity for internal consumption at our Mont Belvieu complex. If this electricity were sold to third parties, our Mont Belvieu cogeneration facilities could be certified as qualifying facilities under the Public Utility Regulatory Policy Act of 1978 ("PURPA"). Subject to compliance with certain conditions under PURPA, this certification would exempt us from most of the regulations applicable to electric utilities under the Federal Power Act and the Public Utility Holding Company Act, as well as from most state laws and regulations concerning the rates, finances, or organization of electric utilities. However, since such electric power is consumed entirely at our facilities, the cogeneration activities are not subject to public utility regulation under federal or Texas law.

General environmental matters

Our operations are subject to federal, state and local laws and regulations relating to the release of pollutants into the environment or otherwise relating to protection of the environment. We believe that our operations and facilities are in general compliance with applicable environmental regulations. However, risks of process upsets, accidental releases or spills are associated with our operations and there can be no assurance that significant costs and liabilities will not be incurred, including those related to claims for damage to property and persons.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, such as emissions of pollutants, generation and disposal of wastes and use and handling of chemical substances. The usual remedy for failure to comply with these laws and regulations is the assessment of administrative, civil and, in some cases, criminal penalties or, in rare cases, injunctions. We believe that the cost of compliance with environmental laws and regulations will not have a significant effect on our results of operations or financial position. However, it is possible that the costs of compliance with environmental laws and regulations will continue to increase, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts currently anticipated. In the event of future increases in cost, we may be unable to pass these increases on to customers. We will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly in order to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance.

We currently own or lease, and have in the past owned or leased, properties that have been used over the years for NGL processing, treatment, transportation and storage and for oil and natural gas exploration and production activities. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, a possibility exists that hydrocarbons and other solid wastes may have been disposed of or otherwise released on various properties that we own or lease or have owned or leased during the operating history of those facilities. In addition, a small number of these properties may have been operated by third parties over whom we had no control as to such entities' handling of hydrocarbons or other wastes and the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become more strict and, pursuant to such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. We do not believe that there presently exists significant surface or subsurface contamination of our properties by hydrocarbons or other solid wastes.

We generate both hazardous and nonhazardous solid wastes which are subject to requirements of the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. From time to time, the EPA has considered making changes in nonhazardous waste standards that would result in stricter disposal requirements for such wastes. Furthermore, it is possible that some wastes currently classified as nonhazardous may be designated as hazardous in the future, resulting in wastes being subject to more rigorous and costly disposal requirements. Such changes in the regulations may result in our incurring additional capital expenditures or operating expenses.

Potential impact of the Superfund law on our operations

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owner or operator of a site and companies that disposed or arranged for the disposal of hazardous substances found at the site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible parties the costs they incur. We may generate "hazardous substances" in the course of our normal business operations. As such, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed; however, we have not been notified of any potential responsibility for cleanup costs under CERCLA.

General impact of the Clean Air Act on our operations

Our operations are subject to the Clean Air Act and comparable state statutes. Amendments to the Clean Air Act were adopted in 1990 and contain provisions that may result in the imposition of certain pollution control requirements with respect to air emissions from our pipelines and processing and storage facilities. For example, the Mont Belvieu processing and storage facilities are located in the Houston-Galveston ozone non-attainment area, which is categorized as a "severe" area and, therefore, is subject to more restrictive regulations for the issuance of air permits for new or modified facilities. The Houston-Galveston area is among nine areas of the country in this "severe" category. One of the other consequences of this non-attainment status is the potential imposition of lower limits on emissions of certain pollutants, particularly oxides of nitrogen which are produced through combustion, such as in the gas turbines at the Mont Belvieu complex.

Regulations imposing more strict air emissions requirements on existing facilities in the Houston-Galveston area were issued in December 2000. These regulations may necessitate extensive redesign and modification of our Mont Belvieu facilities to achieve the air emissions reductions needed for federal Clean Air Act compliance. The technical practicality and economic reasonableness of these regulations have been challenged under state law in litigation filed on January 19, 2001, against the Texas Natural Resource Conservation Commission and its principal officials in the District Court of Travis County, Texas, by a coalition of major Houston-Galveston area industries including the Company. Until this litigation is resolved, the precise level of technology to be employed and the cost for modifying the facilities to achieve the required amount of reductions cannot be determined. Currently, the litigation has been stayed by agreement of the parties pending the outcome of expanded, cooperative scientific research to more precisely define sources and mechanisms of air pollution in the Houston-Galveston area. Completion of this research and formulation of the regulatory response are anticipated in mid-2002. Regardless of the results of this research and the outcome of the litigation, expenditures for air emissions reduction projects will be spread over several years, and we believe that adequate liquidity and capital resources will exist for us to undertake them. We have budgeted capital funds in 2002 to begin making modifications to certain Mont Belvieu facilities that will result in air emission reductions. The methods employed to achieve these reductions will be compatible with whatever regulatory requirements are eventually put in place.

Failure to comply with air statutes or the implementing regulations may lead to the assessment of administrative, civil or criminal penalties, and/or result in the limitation or cessation of construction or operation of certain air emission sources. We believe our operations are in substantial compliance with applicable air requirements.

Impact of the Clean Air Act's oxygenated fuels programs on our BEF investment

We have a 33.33% ownership interest in BEF, which owns a facility currently producing MTBE. The production of MTBE is driven by oxygenated fuels programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation. Any change to these 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 would reduce the demand for MTBE. In 1999, the Governor of California ordered the phase-out of MTBE in California by the end of 2002 due to allegations by several public advocacy and protest groups that MTBE contaminates water supplies, causes health problems and has not been as beneficial in reducing air pollution as originally contemplated. Subsequently, the EPA denied California's request for a waiver of the oxygenate requirement and the state is now reconsidering the timing of its MTBE ban.

Legislation recently introduced in the U.S. Senate, as part of a new Energy Bill, would eliminate the Clean Air Act's oxygenate requirement in order to facilitate the elimination of MTBE in fuel by a certain date, while protecting the fuel alcohol market (primarily ethanol) through a renewable fuels mandate. No such provision exists in the Energy Bill passed by the U.S. House in 2001. Legislation introduced in the U.S. House in 2001 to allow California to ban MTBE was defeated. No assurance can be given as to whether the federal government or individual states will ultimately adopt legislation banning or promoting the use of MTBE as part of their clean air programs.

Impact of the Clean Water Act on our operations

The Federal Water Pollution Control Act, also known as the Clean Water Act, and similar state laws require containment of potential discharges of contaminants into federal and state waters. Regulations pursuant to these laws require companies that discharge into federal and state waters obtain National Pollutant Discharge Elimination System ("NPDES") and/or state permits authorizing these discharges. These laws provide penalties for releases of unauthorized contaminants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of stormwater runoff. We believe that our operations are in substantial compliance with such laws and regulations.

Impact of environmental regulation on our underground storage operations

We currently own and operate underground storage caverns that have been created in naturally occurring salt domes in Texas, Louisiana and Mississippi. These storage caverns are used to store natural gas, NGLs, NGL products and various petrochemicals. Surface brine pits and brine disposal wells are used in the operation of the storage caverns. All of these facilities are subject to strict environmental regulation under the Texas Natural Resources Code and similar statutes in Louisiana and Mississippi. Regulations implemented under such statutes address the operation, maintenance and/or abandonment of such underground storage facilities, pits and disposal wells, and require that permits be obtained. Failure to comply with the governing statutes or the implementing regulations may lead to the assessment of administrative, civil or criminal penalties. We believe that our salt dome storage operations, including the caverns, brine pits and brine disposal wells, are in substantial compliance with applicable statutes.

Safety regulation issues

Our pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act ("HLPSA") and the Natural Gas Pipeline Safety Act, as amended ("NGPSA"), relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA covers crude oil, carbon dioxide, NGL and petroleum products pipelines whereas the NGPSA covers natural gas pipelines and facilities. Both sets of regulations require pipeline owners and/or operators to comply with regulations issued under them, to permit access to and allow copying of records and to make certain reports and provide information as required by the U.S. Secretary of Transportation. Separate legislation to increase the stringency of federal pipeline safety requirements was passed by each of the House and Senate in 2001; however, the two measures have not been reconciled in a conference committee or moved to final passage by the U.S. Congress. We believe that our pipeline operations are in substantial compliance with applicable HLPSA and NGPSA requirements; however, due to the possibility of new or amended laws or the reinterpretation of existing laws, there can be no assurance that future compliance with these pipeline safety requirements will not have an impact on our results of operations or financial position.

The workplaces associated with our company-operated processing, storage and pipeline facilities are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. We believe that our facilities are in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

In general, we expect expenditures associated with industry and regulatory safety standards (such as those described above) will increase in the future. Although such expenditures cannot be accurately estimated at this time, we believe that such expenditures will not have a significant effect on our operations.

Title to Properties

Our real property holdings fall into two basic categories: (1) parcels that we own in fee, such as the land at the Mont Belvieu complex and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our major facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that the Company has satisfactory title to such fee sites. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way or license held by us or to our title to any material lease, easement, right-of-way, permit or license, and we believe that the Company has satisfactory title to all of its material leases, easements, rights-of-way and licenses.

Item 3. Legal Proceedings.

On occasion, we are named as a defendant in litigation relating to our normal business operations. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activity. EPCO has indemnified us against any litigation that was pending at the date of our formation in April 1998.

We are a party to litigation instituted in January 2001 in connection with air emission control regulations in the Houston-Galveston area (see "General impact of the Clean Air Act on our operations" on page 22 for additional information on this subject). Other than this litigation, we are aware of no significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

Item 4. Submission of Matters to a Vote of Security Holders.

There were no matters submitted to a vote of our Unitholders during the fourth quarter of 2001.

PART II

Item 5. Market for Registrant's Common Equity and Related Unitholder Matters.

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.

			Cash Distribution History			
	High	Low	Per Common Unit	Per Subordinated Unit	Record Date	Payment Date
1999						
1st Quarter	$ 18.50	$ 14.94	$ 0.4500	$ 0.0700	Apr. 30, 1999	May 12, 1999
2nd Quarter	$ 18.63	$ 15.06	$ 0.4500	$ 0.3700	Jul. 30, 1999	Aug. 11, 1999
3rd Quarter	$ 20.69	$ 17.88	$ 0.4500	$ 0.4500	Oct. 29, 1999	Nov. 10, 1999
4th Quarter	$ 20.38	$ 17.00	$ 0.5000	$ 0.5000	Jan. 31, 2000	Feb. 10, 2000
2000						
1st Quarter	$ 20.88	$ 18.25	$ 0.5000	$ 0.5000	Apr. 28, 2000	May 10, 2000
2nd Quarter	$ 22.75	$ 19.50	$ 0.5250	$ 0.5250	Jul. 31, 2000	Aug. 10, 2000
3rd Quarter	$ 28.94	$ 22.13	$ 0.5250	$ 0.5250	Oct. 31, 2000	Nov. 10, 2000
4th Quarter	$ 31.88	$ 23.50	$ 0.5500	$ 0.5500	Jan. 31, 2001	Feb. 9, 2001
2001						
1st Quarter	$ 36.80	$ 26.50	$ 0.5500	$ 0.5500	Apr. 30, 2001	May 10, 2001
2nd Quarter	$ 43.75	$ 33.20	$ 0.5875	$ 0.5875	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$ 48.35	$ 39.50	$ 0.6250	$ 0.6250	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$ 52.60	$ 43.60	$ 0.6250	$ 0.6250	Jan. 31, 2002	Feb. 11, 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 March 1, 2002, there were approximately 192 Unitholders of record which includes an estimated 9,900 beneficial owners of our Common Units.

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 will be accomplished by distributing one additional partnership Unit for each partnership Unit outstanding to holders of record on April 30, 2002. The Units will be distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document relate to the pre-split Units, except if indicated otherwise.

Item 6. Selected Financial Data.

The following table sets forth for the periods and at the dates indicated, our selected historical financial data. The selected historical financial data have been derived from our audited financial statements for the periods indicated. The selected historical income statement data for each of the three years ended December 31, 2001, 2000 and 1999 and the selected balance sheet data as of December 31, 2001 and 2000 should be read in conjunction with the audited financial statements for such periods included elsewhere in this report. In addition, information regarding results of operations and capital resources and liquidity can be found under Item 7 of this report.

The dollar amounts in the table, except per Unit data, are in thousands. Additionally, certain reclassifications have been made to prior year's financial statements to conform to the current year presentation.

	2001 (1)	2000 (1)	1999 (1)	1998 (9)	1997
Income statement data:					
Revenues	$3,179,727	$3,073,139	$1,346,456	$754,573	$1,035,963
Gross operating margin (2)	$ 376,783	$ 320,615	$ 179,195	$ 99,627	$ 128,710
Operating income	$ 287,688	$ 243,734	$ 132,351	$ 50,473	$ 75,680
Net income	$ 242,178	$ 220,506	$ 120,295	$ 10,077	$ 52,163
Basic net income per Unit (3)	$ 3.39	$ 3.25	$ 1.79	$ 0.17	$ 0.94
Diluted net income per Unit (4)	$ 2.77	$ 2.64	$ 1.64	$ 0.17	$ 0.94
Balance sheet data (at period end):					
Total assets (5)	$2,431,193	$1,951,368	$1,494,952	$741,037	$ 697,713
Long-term debt (6)	$ 855,278	$ 403,847	$ 295,000	$ 90,000	$ 230,237
Combined equity/Partners' equity (7)	$1,146,922	$ 935,959	$ 789,465	$562,536	$ 311,885
Other financial data:					
Cash distributions declared per Common Unit (8)	$ 2.3875	$ 2.10	$ 1.85	$ 0.77	n/a

(1) Results of operations for the years 2001, 2000 and 1999 have been materially impacted by acquisitions. In 2001, we acquired Acadian Gas and certain Gulf of Mexico natural gas pipeline systems. In 1999, we acquired the TNGL natural gas processing and NGL businesses from Shell. These acquisitions have significantly increased revenues, gross operating margin, operating income and net income since their respective completions.
(2) Gross operating margin 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.
(3) Net income allocable to our limited partners divided by the weighted-average number of Common and Subordinated Units outstanding during the period.
(4) Net income allocable to our limited partners divided by the weighted-average number of Common, Subordinated and Special Units outstanding during the period.
(5) Total assets have increased significantly since 1999 primarily as a result of acquisitions.
(6) Long-term debt increased in 2001 and 2000 as a result of the issuance of public debt to finance acquisitions and other general partnership purposes. Long-term debt increased in 1999 over 1998 as a result of borrowings under revolving credit facilities to finance the TNGL and MBA acquisitions in 1999. The decrease in long-term debt in 1998 compared to 1997 is due to use of the proceeds from our initial public offering in July 1998 to paydown debt assumed from EPCO.
(7) Partners' equity increased in 2001 and 2000 in part as a result of the issuance of an additional 6.0 million Special Units to Shell in connection with the TNGL acquisition. Using present value techniques, the 3.0 million Special Units issued during 2000 were valued at approximately $55 million while the 3.0 million Special Units issued during 2001 were valued at $117 million. See Note 7 of the Notes to Consolidated Financial Statements for additional information regarding our capital structure.
(8) Cash distributions began after our initial public offering of Common Units on July 27, 1998. See Item 5 for additional information regarding cash distributions.
(9) Net income for 1998 includes a $27 million extraordinary charge on early extinguishment of debt.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation.

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and notes thereto included elsewhere herein as well as the other portions of this report on Form 10-K. In addition, the reader should review "Cautionary Statement regarding Forward-Looking Information and Risk Factors" beginning on page 1 of this report for information regarding forward-looking statements made in this discussion and certain risks inherent in our business. Other risks involved in our business are discussed under Item 7A "Quantitative and Qualitative Disclosures about Market Risks" beginning on page 47 of this report. Additionally, please see Part III, Item 13 for a discussion of related-party issues such as the EPCO Agreement and our relationship with Shell.

General

During the last three years, we have completed or initiated several acquisitions and investments having a combined value of over $1.4 billion. These include $571 million in natural gas processing and NGL businesses, $438 million in natural gas and other pipeline businesses and $368 million in propylene fractionation and NGL/petrochemical storage assets. Specifically, we have completed the following acquisitions and asset purchases:

- $529 million paid to acquire TNGL's natural gas processing and NGL businesses (1999);
- $42 million paid to acquire an additional interest in the Mont Belvieu NGL fractionation facility (1999);
- $100 million paid to acquire the Lou-Tex Propylene pipeline (2000);
- $226 million paid to acquire the Acadian Gas natural gas pipeline network (2001);
- $112 million invested in four Gulf of Mexico natural gas pipeline systems (2001);
- $129 million paid to purchase storage assets in Mont Belvieu (initiated 2001, completed January 2002); and
- $239 million paid to purchase a controlling interest in a propylene fractionation facility and related assets in Mont Belvieu (initiated 2001, completed February 2002).

During 2001, we issued the last installment of 3.0 million Special Units to Shell valued at approximately $117 million. These new Special Units were issued in connection with the TNGL acquisition that was completed in 1999, resulting in a final total purchase price of $529 million.

We entered the natural gas pipeline business in 2001 by completing the acquisition of Acadian Gas and investments in four Gulf of Mexico natural gas pipeline systems. In April 2001, we acquired Acadian Gas (an onshore Louisiana system) from an affiliate of Shell for $226 million using proceeds from the issuance of public debt. Acadian Gas and its affiliates are involved in the purchase, sale, transportation and storage of natural gas in Louisiana. Its assets include 1,042 miles of natural gas pipelines and a leased natural gas storage facility. In January 2001, we paid El Paso $112 million for equity interests in four Gulf of Mexico offshore Louisiana natural gas pipeline systems. These systems are comprised of 739 miles of regulated and non-regulated natural gas pipelines. The acquisition of these businesses represent strategic investments for the Company. We believe that these assets have attractive growth attributes given the expected long-term increase in natural gas demand for industrial and power generation uses. In addition, these assets extend our midstream energy service relationship with long-term NGL customers (producers, petrochemical suppliers and refineries). These assets also provide opportunities for enhanced services to customers and generate additional fee-based cash flows.

2002 developments. In January 2002, we completed the acquisition of Diamond-Koch's ("D-K") Mont Belvieu storage assets from affiliates of Valero Energy Corporation and Koch Industries, Inc. for $129 million. These facilities include 30 storage wells with a useable capacity of 68 MMBbls and allow for the storage of mixed NGLs, ethane, propane, butanes, natural gasoline and olefins (such as ethylene), polymer grade propylene, chemical grade propylene and refinery grade propylene. With the inclusion of the former D-K facilities, we own and operate 95 MMBbls of storage capacity at Mont Belvieu, one of the largest such facilities in the world. In addition, we completed the purchase of D-K's 66.7% interest in a propylene fractionation facility and related assets in February 2002 at a cost of approximately $239 million. Including this purchase, we effectively own 58.3 MBPD of net propylene fractionation capacity in Mont Belvieu and have access to additional customers at this key industry hub.

Our outlook for first half of 2002

The year 2001 was an economically challenging period for the NGL and petrochemical industries. The domestic NGL industry was adversely affected by abnormally high natural gas prices during the first quarter of 2001 resulting in a substantial reduction in NGL extraction rates at virtually all gas processing plants industry wide. As natural gas prices moderated during the remainder of 2001, industry wide extraction rates returned to normalized levels resulting in increased volumes and profitability across many of our business operations.

Our outlook for the first half of 2002 is more favorable than what we experienced during the first half of 2001. Overall, we expect NGL extraction rates for the gas processing industry to continue near the levels sustained during the fourth quarter of 2001 due to stabilized processing margins. Should this forecast be realized, our equity NGL production rate would approximate 75 to 85 MBPD during the first half of 2002 as compared to 54 MBPD during the same period in 2001. Our outlook is based on the market price of natural gas remaining within the historical norm in terms of its relative value to other forms of energy. After peaking at near $10 per MMBtu in January 2001, natural gas prices decreased to near $2 per MMBtu during the fourth quarter of 2001 which is within the historical norm. The forecasted market price of natural gas for the first half of 2002 should continue to make it economically attractive to recover NGLs at higher levels even though downstream demand has been reduced due to the downturn in the world economy. Barring any major disruptions, industry expectations are that natural gas market prices will remain stable for the first half of 2002 due to strong supply.

Drilling activity in the Gulf of Mexico increased significantly in early 2001 in response to the abnormally high price of natural gas during that period. With the moderation in energy prices over the last half of 2001, drilling activity began to decline (continuing into early 2002). Over time, however, we expect that the improving domestic economy and new gas fired electric generation facilities will increase demand for natural gas and thus strengthen the price and stimulate increased drilling. As drilling increases, we expect our Gulf of Mexico natural gas pipeline systems to benefit; however, if drilling activity continues to be suppressed over the longer-term, these investments could be adversely affected by reduced volumes.

We expect Acadian Gas to benefit from two new gas-fired cogeneration facilities commencing operations during 2002, one of which should begin operations during the second quarter of 2002. This will help to offset lower pipeline throughput volumes expected in the first five months of 2002 caused by a seasonal decrease in natural gas demand due to warmer weather. By the end of the second quarter of 2002, pipeline throughput volumes should rise due to an increase in gas consumption by electricity providers as a result of the beginning of summer air conditioning demands.

We expect that utilization of our Lou-Tex NGL pipeline will be higher during the first half of 2002 as a result of additional pipeline throughput volumes (primarily propane and butane coming from Louisiana locations and a continuation of raw make production volumes being moved from the Sea Robin gas processing facility to Mont Belvieu). Due to a mild winter in the continental U.S., we are capturing additional revenue from transporting propane on this system out of Louisiana to Mont Belvieu for export to overseas markets. The relatively warm winter in the southeastern U.S. has also adversely affected propane shipments on the Dixie pipeline system; therefore, some of their propane shipments are being diverted to Mont Belvieu for storage, export, petrochemical and other uses.

As a result of these increased propane exports, we project that EPIK will have a full loading schedule extending early into the second quarter of 2002. Export activity will decline during the summer months when demand for propane for heating is reduced. Our import terminal is expected to have a typical first quarter as imports are historically low during this period and 2002 looks to be no exception. However, we expect that the second quarter of 2002 will provide opportunities for importing cargoes of mixed butane and anticipate that the unloading facility will be heavily utilized. The HSC pipeline should benefit from an increase in exports during the first quarter and an increase in imports during the second quarter. We may also see an increase in pipeline shipments of propane/propylene mix due to the purchase of the D-K propylene fractionator. Lastly, throughput volumes on the Tri-States, Wilprise and Belle Rose systems are expected to average 45 MBPD during the first half of 2002 compared to 24 MBPD during the first half of 2001. The lower rate in 2001 was due to lower NGL extraction rates by gas processing facilities.

We expect continued strong demand for our hydrocarbon storage services due to the continued recovery of NGLs by gas processing facilities. With the purchase of D-K's Mont Belvieu storage assets, we will be offering additional opportunities to customers during 2002 in the form of expanded services, options, and flexibility for the delivery and/or consumption of their NGLs. These additional services should provide additional margins as we integrate the former D-K assets with our existing Mont Belvieu operations.

NGL fractionation services at Mont Belvieu will remain competitive due to excess NGL fractionation capacity at this industry hub. To offset lower fractionation tolling fees, we have increased feed rates at our Mont Belvieu NGL fractionation facility over the last year with the addition of newly contracted volumes such as the mixed NGL stream coming from the Sea Robin gas processing plant in Louisiana (via the Lou-Tex NGL pipeline). During the first quarter of 2002, our isomerization business has benefited from increased refinery demand for isobutane. The market price spread between normal butane and isobutane during the first quarter of 2002 has been two to four cents higher than normal levels as a result of this strong demand, which should benefit margins in our Processing segment's merchant business. We expect isobutane pricing to trend toward the historical norm by the end of the first quarter and remain so during the second quarter. Propylene fractionation unit margins are expected to remain flat during the first half of 2002 due to the weak economy and additional supplies coming to market from new third party facilities. If the domestic economy improves as anticipated during 2002, we expect that the demand for propylene fractionation services will increase as the market absorbs the additional market supply.

Our MTBE facility underwent its annual maintenance turnaround in January 2002. Equity earnings from this facility for the first quarter of 2002 are expected to benefit from strong MTBE pricing caused by a number of other MTBE units undergoing maintenance turnarounds which reduced overall MTBE supply. As we enter the second quarter of 2002, MTBE pricing is expected to further strengthen as refiners begin purchasing MTBE in preparation for gasoline blending requirements for the upcoming summer driving season.

The following table illustrates selected average quarterly prices for natural gas, crude oil, selected NGL products and polymer grade propylene since the first quarter of 1999:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Polymer Grade Propylene, $/pound
	(1)	(2)	(1)	(1)	(1)	(1)	(1)
Fiscal 1999:							
First quarter	$1.70	$13.05	$0.20	$0.24	$0.29	$0.31	$0.12
Second quarter	$2.12	$17.66	$0.27	$0.31	$0.37	$0.38	$0.13
Third quarter	$2.56	$21.74	$0.34	$0.42	$0.49	$0.49	$0.16
Fourth quarter	$2.52	$24.54	$0.30	$0.41	$0.52	$0.52	$0.19
Fiscal 2000:							
First quarter	$2.49	$28.84	$0.38	$0.54	$0.64	$0.64	$0.21
Second quarter	$3.41	$28.79	$0.36	$0.52	$0.60	$0.68	$0.26
Third quarter	$4.22	$31.61	$0.40	$0.60	$0.68	$0.67	$0.26
Fourth quarter	$5.22	$31.98	$0.49	$0.67	$0.75	$0.73	$0.24
Fiscal 2001:							
First quarter (3)	$7.00	$28.81	$0.43	$0.55	$0.63	$0.69	$0.23
Second quarter	$4.61	$27.88	$0.33	$0.46	$0.53	$0.63	$0.19
Third quarter	$2.84	$26.60	$0.25	$0.41	$0.50	$0.49	$0.16
Fourth quarter	$2.38	$20.40	$0.21	$0.33	$0.39	$0.38	$0.18

(1) Natural gas, NGL and polymer grade propylene prices represent an average of index prices
(2) Crude Oil price is representative of West Texas Intermediate
(3) Natural gas prices peaked at approximately $10 per MMBtu in January 2001

Our 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, 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 deterioration 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 and 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, 2001 and 2000, the net book value (or undepreciated cost) of our property, plant and equipment was $1.3 billion and $1.0 billion. For additional information regarding our property, plant and equipment see Note 3 of the Notes to Consolidated Financial Statements.

Intangible assets. Our recorded intangible assets primarily include the values assigned to contract-based assets that have a fixed or definite term. At December 31, 2001, the principal item recorded as an intangible asset was the 20-year Shell natural gas processing agreement. The value of this contract is being amortized on a straight-line basis over its contract term (currently $11.1 million annually from 2002 through July 2019). If the economic life of this contract were later determined to be impaired due to negative changes in Shell's natural gas exploration and production activities in the Gulf of Mexico, then we might need to reduce the amortization period of this asset to less than the contractually-stated 20-year life of the agreement. Such a change would increase the annual amortization charge at that time. At December 31, 2001, the unamortized value of this contract was $194.4 million.

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 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 short-term nature of these estimates.

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);
- In-kind fractionation arrangements where we process customer mixed NGL volumes for a percentage of the end NGL products in lieu of a cash fee (exclusive to our Norco NGL fractionation facility);
- Merchant 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 (or throughput) 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. A special type of tolling arrangement, an "in-kind" contract, is utilized by various customers at our Norco NGL fractionation facility. An in-kind processing contract allows us to retain a contractually-determined percentage of NGL products produced for the customer in lieu of a cash tolling fee per gallon. Revenue is recognized from these "in-kind" contracts when we sell (at market-related prices) and deliver the fractionated NGLs that we retained.

Our Processing segment businesses employ tolling and merchant 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 we retain mixed NGLs as our fee for natural gas processing services, we record revenue when the NGLs (in mixed and/or fractionated product form) are sold and delivered to customers using merchant contracts. In addition to the Processing segment, merchant contracts are utilized in the Fractionation segment to record revenues from the sale of propylene volumes and in the Pipelines segment to record revenues from the sale of natural gas. Our merchant contracts are generally based on market-related prices as determined by the individual agreements.

We have established an allowance for doubtful accounts to cover potential bad debts from customers. Our allowance amount is generally determined as a percentage of revenues for the last twelve months. In addition, we may also increase the allowance account in response to specific identification of customers involved in bankruptcy proceedings and the like. We routinely review our estimates in this area to ascertain that we have recorded ample reserves to cover forecasted losses. If unanticipated financial difficulties were to occur with a significant customer or customers, there is the possibility that the allowance for doubtful accounts would need to be increased to bring the allowance up to an appropriate level based on the new information obtained. Our allowance for doubtful accounts at December 31, 2001 was $20.6 million.

Fair value accounting for 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 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. Currently none of these 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 results in a degree of non-cash earnings volatility that is dependent 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. At December 31, 2001, our financial statements reflected $5.6 million of mark-to-market income related to commodity financial instruments whose longest maturity date was December 2002. 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 Item 7A on page 47.

Additional information regarding the significant accounting policies underlying preparation of our financial statements (including revenue recognition) can be found in Note 1 of the Notes to Consolidated Financial Statements on page F-7.

Our results of operations

We have five reportable operating segments: Fractionation, Pipelines, Processing, Octane Enhancement and Other. Fractionation primarily includes NGL fractionation, isomerization and propylene fractionation. Pipelines consists of liquids and natural gas pipeline systems, storage and import/export terminal services. Processing includes our natural gas processing business and related merchant activities. Octane Enhancement represents our interest in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment primarily consists of fee-based marketing services.

Our management evaluates segment performance based on gross operating margin ("gross operating margin" or "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 interest expense, interest income amounts, dividend income, minority interest, extraordinary charges and other income and expense transactions.

We include equity earnings from unconsolidated affiliates in segment gross operating margin and as a component of revenues. 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 these businesses 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 merchant businesses. 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.

Our gross operating margin by segment (in thousands of dollars) along with a reconciliation to consolidated operating income for the past three years were as follows:

	For Year Ended December 31,		
	2001	2000	1999
Gross Operating Margin by segment:			
Fractionation	$ 118,610	$129,376	$110,424
Pipeline	96,569	56,099	31,195
Processing	154,989	122,240	28,485
Octane enhancement	5,671	10,407	8,183
Other	944	2,493	908
Gross Operating margin total	376,783	320,615	179,195
Depreciation and amortization	48,775	35,621	23,664
Retained lease expense, net	10,414	10,645	10,557
Loss (gain) on sale of assets	(390)	2,270	123
Selling, general and administrative expenses	30,296	28,345	12,500
Consolidated operating income	$ 287,688	$243,734	$132,351

Our significant plant production and other volumetric data for the last three years were as follows:

	For Year Ended December 31,		
	2001	2000	1999
MBPD, Net			
Equity NGL Production	63	72	67
NGL Fractionation	204	213	184
Isomerization	80	74	74
Propylene Fractionation	31	33	28
Octane Enhancement	5	5	5
Major NGL and Petrochemical Pipelines	454	367	264
BBtu/D, Net			
Natural Gas Pipelines	1,349	n/a	n/a

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

Revenues, costs and expenses and operating income. Fiscal 2001 was our best year ever as measured in terms of revenues, gross operating margin and operating income. Our revenues were a record $3.2 billion in 2001 compared to $3.1 billion in 2000. Operating costs and expenses increased to $2.9 billion in 2001 from $2.8 billion in 2000. Gross operating margin increased to $376.8 million in 2001 from $320.6 million in 2000. Operating income also posted a record $287.7 million in 2001 versus $243.7 million in 2000. The increases in revenues and costs and

expenses are primarily due to our natural gas pipeline acquisitions completed in 2001 (Acadian Gas and the Gulf of Mexico lines) offset by lower product prices in 2001 relative to 2000. The increase in gross operating margin and operating income is primarily attributable to acquisitions and new construction, plus a rise in income relating to commodity hedging activities offset by generally lower product prices.

Fractionation. Gross operating margin from our Fractionation segment decreased to $118.6 million in 2001 from $129.4 million in 2000. NGL fractionation margin for 2001 declined $21.0 million from 2000, primarily as the result of a $19.3 million decrease in "in-kind" fractionation fees at our Norco facility. An in-kind arrangement allows us to receive NGL volumes in lieu of cash fractionation fees (Norco being our only facility with this type of contract). The decline in NGL fractionation margin is related to the NGL volumes received during 2000 having a higher value than those received during 2001. Net volumes at the NGL fractionation facilities decreased to 204 MBPD in 2001 compared to 213 MBPD in 2000. The decrease in throughput is due to lower NGL extraction rates at gas processing facilities in early 2001 (due to the abnormally high cost of natural gas) versus 2000 when the industry was maximizing NGL production. The isomerization business posted an $8.4 million increase in margin for 2001 over 2000 on volumes of 80 MBPD. Isomerization margins were bolstered by increased demand during the second quarter of 2001 for services linked to refinery activities, primarily gasoline blending. 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 July 2000. Net volumes at our propylene fractionation facilities declined slightly to 31 MBPD in 2001 from 33 MBPD in 2000.

Pipelines. Our Pipelines segment posted a record gross operating margin of $96.6 million in 2001, compared to $56.1 million in 2000. Of the $40.5 million increase in margin, $20.0 million is attributable to natural gas pipelines acquired in 2001 (i.e., Acadian Gas and the Gulf of Mexico systems). Acadian Gas added $11.8 million in margin with the Gulf of Mexico systems contributing $8.2 million. On a net basis, these pipeline systems transported an average of 1,349 BBtu/d of natural gas.

Net liquid transportation volumes increased to 454 MBPD in 2001 from 367 MBPD in 2000. The majority of this increase is attributable to a rise in commercial butane imports related to seasonal demand for isobutane production. This activity contributed to a $5.2 million combined increase in margin from our import terminal and HSC pipeline system. Additionally, margin from the Louisiana Pipeline System increased $1.1 million in 2001 due to increased demand for transportation services (with volumes increasing by 23 MBPD in 2001, a 20% increase year-to-year). Also, our recently completed Lou-Tex NGL pipeline added $12.2 million to margin during 2001 (construction of this system being completed in the fourth quarter of 2000). This pipeline benefited from the movement of mixed NGLs out of Louisiana to our Mont Belvieu processing facility during 2001.

Processing. Earnings from our Processing segment were a record $155.0 million in 2001, up 27% from $122.2 million in 2000. This segment is comprised of our natural gas processing business and related merchant activities. The increase in margin is primarily due to the positive impact of our commodity hedging activities.

2001 was a very challenging year for gas processors industry wide. The volatility of natural gas prices and the depressed nature of NGL prices throughout 2001 created an environment requiring processors to be proactive in meeting the needs of the marketplace. The unusually poor processing economics of the first quarter of 2001 (due to the abnormally high cost of energy relative to the value of our NGL production during that time) yielded to improved market conditions during the second half of 2001 as energy costs moderated. In general, prices received for our NGL production approximated a weighted-average of 43 cents per gallon in 2001 compared to 57 cents per gallon in 2000. In contrast, the cost of natural gas averaged $4.20 per MMBtu in 2001 (peaking at near $10 per MMBtu during the first quarter of 2001) versus $3.84 per MMBtu in 2000.

Equity NGL production averaged 63 MBPD in 2001 compared to 72 MBPD in 2000. The decline in volume is related to the 2000 period reflecting near maximized NGL recoveries supported by strong NGL economics. The 2001 equity NGL production rate reflects less favorable extraction economics (as described above) but is greatly improved relative to the first quarter of 2001's 46 MBPD when energy costs peaked. With the improvement in processing margins in late 2001, we posted a record equity NGL production of 80 MBPD during the fourth quarter of 2001.

We employ various hedging strategies to mitigate the effects of fluctuating commodity prices (primarily NGL and natural gas prices) on our gas processing business and related merchant activities. Margin for 2001 includes $101.3 million of income from commodity hedging activities, an increase of $74.5 million over such income in 2000. The loss in value of our NGL production has been mitigated (or in some cases, exceeded) by such income during 2001. Without this income, margin from gas processing would have declined $54.7 million year-to-year.

A large number of our commodity financial instruments are currently based on the historical relationship between natural gas prices and NGL prices. This type of hedging strategy utilizes 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 merchant activities and the value of our equity NGL production. During 2001, we benefited from the general decline in natural gas prices relative to our fixed positions. The decline in natural gas prices allowed us to realize net cash gains on the settlement and closeout of certain positions of approximately $95.7 million. The $5.6 million difference between the realized amount and the $101.3 million in income from these financial instruments represents the non-cash mark-to-market income on positions open at December 31, 2001 (based on market prices at that date).

If natural gas prices had not declined to the degree seen during the year, we would have recognized less income (or potentially even a loss) on hedging activities offset somewhat by correlative higher NGL prices which would have increased the value of our NGL production. A variety of factors influence whether or not our hedging strategies are successful. For additional information regarding our commodity financial instruments, see Item 7A "Quantitative and Qualitative Disclosures about Market Risk" beginning on page 47.

We are exposed to settlement risk (a form of credit risk) with our counterparties to these financial instruments. On all transactions where we are exposed to settlement risk, management analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit limits and monitors 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 recognized a charge to 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.

Our merchant activities benefited from (i) strong propane demand in the first quarter of 2001 for heating and (ii) isobutane in the second quarter of 2001 for refining. Overall, margin from merchant activities improved $9.9 million year-to-year. Processing margin also benefited from the reversal of $9.4 million in excess reserves associated with the gas processing plants.

Octane Enhancement. Equity earnings from our BEF investment declined $4.7 million year-to-year on stable net volumes of 5 MBPD in both periods. The decrease in earnings is primarily attributable to lower MTBE and by-product prices.

Other. Gross operating margin from our Other segment was $0.9 million in 2001 compared to $2.5 million in 2000. The decrease is primarily due to a rise in operating costs of plant support functions.

Selling, general and administrative expenses. These expenses increased to $30.3 million in 2001 from $28.3 million in 2000. The increase is primarily due to expenses related to the additional staff and resources deemed necessary to support our expansion activities resulting from acquisitions and other business development.

Interest expense. Interest expense for 2001 increased by $19.1 million over that for 2000 . The increase is primarily due to the issuance of our $450 million of public debt in January 2001 (the Senior Notes B, see page 41). The proceeds from this debt were used to acquire the Gulf of Mexico pipelines from El Paso, Acadian Gas from Shell and to finance internal growth and other general partnership purposes.

Interest expense for both 2001 and 2000 benefited from income attributable to interest rate hedging activity. During the last two years, we used interest rate swaps in order to effectively convert a portion of our fixed-rate debt into variable-rate debt. With the decline in variable interest rates over the last two years, our swaps provided income to offset fixed-rate-based interest expense. For 2001, we recognized a $13.2 million benefit related to these swaps compared with a $10.0 million benefit recorded in 2000.

During 2001, two of our three swaps that were outstanding at January 1, 2001 were terminated (closing instruments having a notional value of $100 million). One swap was terminated by a counterparty exercising its early termination option while the other counterparty negotiated an early closeout of its position. This left us with one swap outstanding at December 31, 2001 having a notional amount of $54 million. This swap has an early termination option that is exercisable in March 2003. For additional information regarding our exposure to interest rate risk, see page 49.

Year ended December 31, 2000 compared to year ended December 31, 1999

Revenues, costs and expenses and operating income. Our revenues increased to $3.1 billion in 2000 compared to $1.3 billion in 1999 while operating costs and expenses increased to $2.8 billion in 2000 versus $1.2 billion in 1999. Gross operating margin increased to $320.6 million in 2000 compared to $179.2 million in 1999 resulting in a year-to-year increase in operating income of $111.4 million to $243.7 million in 2000 from $132.3 million in 1999. The year-to-year increase in revenues, operating costs and expenses, gross operating margin and operating income is primarily attributable to the TNGL acquisition. The 1999 period includes five months of margins associated with TNGL operations (August through December) whereas the 2000 period includes twelve months.

Fractionation. The gross operating margin of our Fractionation segment increased to $129.4 million in 2000 from $110.4 million in 1999. The additional margin from the NGL fractionators acquired from Shell in the TNGL acquisition was the primary reason for a $29.7 million increase in NGL fractionation margin in 2000 over 1999. As noted previously, 1999 includes five months of margin from the TNGL assets whereas the 2000 period includes twelve months. Net NGL fractionation volume increased to 213 MBPD in 2000 from 184 MBPD in 1999. The increase in net NGL fractionation volume is attributable to higher production rates at our Mont Belvieu NGL fractionator. Our ownership in this facility increased to 62.5% from 37.5% as a result of the July 1999 MBA acquisition.

For 2000, gross operating margin from our isomerization business decreased $7.8 million compared to 1999 primarily due to higher fuel and other operating costs, plus the expenses related to the refurbishment of an isomerization unit. Isomerization volumes were 74 MBPD in both 2000 and 1999. Gross operating margin from propylene fractionation decreased $1.4 million in 2000 from 1999 levels primarily due to higher energy costs. Net volumes at these facilities improved to 33 MBPD in 2000 from 28 MBPD in 1999 due to the startup of the BRPC propylene concentrator in July 2000.

Pipelines. Gross operating margin from our Pipelines segment was $56.1 million in 2000 compared to $31.2 million in 1999. Overall liquids volumes increased to 367 MBPD in 2000 from 264 MBPD in 1999. Generally, the $24.9 million increase in margin is attributable to the additional volumes and margins contributed by the TNGL pipeline and storage assets, higher margins from the HSC pipeline system and EPIK due to an increase in export volumes, the margins from the Lou-Tex propylene pipeline that was purchased in March 2000 and margins from the Lou-Tex NGL pipeline which commenced operations in late November 2000. The growth in export volumes is attributable to the installation of EPIK's new chiller unit that began operations in the fourth quarter of 1999.

On February 25, 2000, the purchase of the Lou-Tex propylene pipeline and related assets from Shell was completed at a cost of approximately $99.5 million. Construction of the Lou-Tex NGL pipeline was completed during the fourth quarter of 2000 at a cost of approximately $87.9 million.

Processing. Our Processing segment generated $122.2 million in gross operating margin during 2000 compared to $28.5 million in 1999. The $93.7 million increase is primarily due to 2000 including twelve months of gas processing (and related merchant activity) margins from the TNGL businesses; whereas 1999 includes only five months. This segment benefited from a stronger NGL pricing environment in 2000 versus 1999 and a rise in equity NGL production from 67 MBPD in 1999 to 72 MBPD in 2000.

Octane Enhancement. Gross operating margin from our Octane Enhancement segment increased to $10.4 million in 2000 from $8.2 million in 1999. This segment consists entirely of our investment in BEF, a joint venture facility that currently produces MTBE. Equity earnings for 2000 improved over 1999 levels primarily due to higher than normal MTBE market prices during the second and third quarters of 2000 and lower debt service costs (BEF made its final note payment in May 2000 and, as a result, now owns the facility debt-free). In addition, the 1999 period reflects a $1.5 million non-cash charge related to the write-off of certain start-up expenses. MTBE production, on a net basis, was 5 MBPD in both 2000 and 1999.

Other. Gross operating margin from our Other segment was $2.5 million in 2000 compared to $0.9 million in 1999. The increase is primarily due to fee-based marketing services added in the fourth quarter of 1999.

Selling, general and administrative expenses. These expenses increased to $28.3 million in 2000 from $12.5 million in 1999. The increase is primarily due to expenses related to the additional staff and resources deemed necessary to support our expansion activities resulting from acquisitions and other business development.

Interest expense. Interest expense increased to $33.3 million in 2000 from $16.4 million in 1999. The increase is attributable to a rise in average debt levels from $213 million in 1999 to $408 million in 2000. Debt levels have increased over the previous year primarily due to capital expenditures for assets such as the Lou-Tex propylene and Lou-Tex NGL pipelines and the issuance of $404 million in debt instruments (the Senior Notes A and MBFC Loan) in March 2001. Interest expense for 2000 includes a $10.0 million benefit related to interest rate swaps.

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 partners. We expect to fund our short-term needs for such items as operating expenses, sustaining capital expenditures and quarterly distributions to partners 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 bank credit facilities and the issuance of additional Common Units and public debt. 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 flows from operations are directly linked to earnings from our business activities. Like our results of operations, 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 and in the production of motor gasoline and as fuel for residential 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 page 1.

As noted above, certain of our liquidity and capital resource requirements are met using borrowings under bank credit facilities and/or the issuance of additional Common Units or public debt (separately or in combination). As of December 31, 2001, availability under our revolving credit facilities was $400 million (which may be increased by an additional $100 million under certain conditions). We issued $450 million of public debt in January 2001 (the "Senior Notes B") using the remaining availability under the December 1999 $800 million universal shelf registration. The proceeds of this offering were used to acquire Acadian Gas and the Gulf of Mexico natural gas pipeline systems, to finance the cost to construct certain NGL pipelines and related projects and for working capital and other general partnership purposes. On February 23, 2001, we filed a $500 million universal shelf registration (the "February 2001 Shelf") covering the issuance of an unspecified amount of equity or debt securities or a combination thereof. For additional information regarding our debt, see the section below labeled "Long-term debt."

In June 2000, we received approval from our Unitholders to increase by 25,000,000 the number of Common Units available (and unreserved) for general partnership purposes during the Subordination Period. This increase has improved our future financial flexibility in any potential expansion project or business acquisition. After taking into account the Units issued in connection with TNGL acquisition, 27,275,000 Units are available (and unreserved) on a pre-split basis (see "Two-for-one split of Limited Partner Units" below) for general partnership purposes during the Subordination Period which generally extends until the first day of any quarter beginning after June 30, 2003 when certain financial tests have be satisfied. After this period expires, we may prudently issue an unlimited number of Units for general partnership purposes.

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.

Credit ratings. Our current investment grade credit ratings of Baa2 by Moody's Investor Service and BBB by Standard and Poors highlight our financial flexibility. The outlook for both of the ratings is stable. We maintain regular communications with these rating agencies which independently judge our creditworthiness based on a variety of quantitative and qualitative factors. In May 2001, Moody's upgraded their rating of us from Baa3 to Baa2. They cited that our operating capabilities and growth opportunities had been significantly enhanced by the acquisition of Acadian Gas and the purchase of equity interests in four Gulf of Mexico natural gas pipeline systems. We believe that the maintenance of an investment grade credit rating is important in managing our liquidity and capital resource requirements.

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 will be accomplished by distributing one additional partnership Unit for each partnership Unit outstanding to holders of record on April 30, 2002. The Units will be distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document relate to the pre-split Units, except if indicated otherwise.

Consolidated cash flows for year ended December 31, 2001 compared to year ended December 31, 2000

Operating cash flows. Cash flows from operating activities were $283.3 million in 2001 versus $360.9 million in 2000. After adjusting for changes in operating accounts which are generally the result of timing of sales and purchases near the end of each period, adjusted cash flow from operating activities would be $320.4 million in 2001 as compared to $289.8 million in 2000. Cash flow from operating activities before changes in operating accounts is an important measure of our liquidity. It provides an indication of our success in generating core cash flows from the assets and investments that we own. The $30.7 million increase for 2001 is attributable to our strong earnings as discussed earlier under "Our results of operations - Year ended December 31, 2001 compared to year ended December 31, 2000."

Investing cash flows. During 2001, we used $491.2 million of cash to finance investing activities compared to $268.8 million in 2000. Over the last two years, we have funded $384.3 million in internal growth projects. Of this amount, $336.2 million in capital expenditures has been devoted to various pipeline projects including $99.5 million spent to purchase the Lou-Tex Propylene pipeline (2000), $90.5 million to construct the Lou-Tex NGL pipeline ($83.7 million spent in 2000 with the remainder spent in 2001) and $64.1 million in expansion activities related to our Louisiana Pipeline System (2001). We spent $9.5 million on sustaining capital expenditures during the last two years with $6.0 million in such charges recorded during 2001.

Our investing cash outflows for 2001 include the $225.7 million paid to acquire Acadian Gas from Shell. This amount is subject to certain post-closing adjustments expected to be completed during the first half of 2002. In addition, our investments in and advances to unconsolidated affiliates increased $84.7 million in 2001 due to the $112.0 million paid to purchase equity interests in several Gulf of Mexico natural gas pipeline systems from El Paso.

Financing cash flows. Our financing activities generated $279.5 million of cash receipts during 2001 compared to cash payments of $36.9 million in 2000. Cash flows from financing activities are primarily affected by repayments of debt, borrowings under debt agreements and distributions to partners. Cash flow from financing activities in 2001 includes proceeds from the $450 million Senior Notes B issued in January 2001 whereas the 2000 period includes proceeds from the $350 million Senior Notes A and $54 million MBFC loan and the associated repayments on various bank credit facilities.

Cash distributions to partners and the minority interest increased to $166.0 million in 2001 from $141.0 million in 2000 primarily due to (i) increases in the quarterly distribution rate and (ii) the conversion of 5.0 million of Shell's Special Units into Common Units. See Note 9 of the Notes to Consolidated Financial Statements for a history of quarterly distribution rates and increases since the first quarter of 1999. Our cash distribution policy (as managed by the General Partner at its sole discretion) has allowed us to retain a significant amount of cash flow for reinvestment in the growth of the business. Over the last two years, we have retained approximately $275.0 million to fund expansions and business acquisitions. We believe that our cash distribution policy provides the partnership with financial flexibility in executing its growth strategy.

In July 2000, the General Partner instituted a two-year buy-back program (the "Buy Back Program") that would allow Enterprise Products Partners L.P. ("EPPLP", on a stand-alone basis) to repurchase and retire up to 1.0 million of its publicly-owned Common Units. Our intent under the Buy Back Program is to reacquire Common Units during periods of temporary market weakness at price levels that would be accretive to our remaining Unitholders. Under this original program, EPPLP repurchased and retired 28,400 Common Units during 2000 at a cost of $0.8 million.

During the first quarter of 1999, we established a revocable grantor trust (the "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). At December 31, 2001, this consolidated Trust owned 163,600 Common Units (the "Trust Units") which are accounted for in a manner similar to treasury stock under the cost method of accounting. The Trust Units are considered outstanding and receive distributions; however, they are excluded from the calculation of earnings per Unit.

In September 2001, the General Partner modified the Buy Back Program to allow both EPPLP and the Trust to repurchase Common Units. Under the modified terms of the program, purchases made by EPPLP will be retired whereas the Units purchased by the Trust will remain outstanding and not be retired. At December 31, 2001, 575,200 additional publicly-owned Common Units (on a pre-split basis) could be repurchased under the Buy Back Program by EPPLP and/or the Trust.

Purchases made under this program by EPPLP will be funded by special cash distributions from the Operating Partnership whereas purchases made by the Trust will be funded by cash contributions from the Operating Partnership. These purchases will be balanced with our plans to grow the Company through investments in internally-developed projects and acquisitions, while maintaining an investment grade debt rating. The Trust purchased 396,400 Common Units under this program during 2001 at a cost of $18.0 million. The Trust subsequently reissued 500,000 treasury units for proceeds of $22.6 million. For additional information regarding the Trust, see Note 7 of the Notes to Consolidated Financial Statements.

At December 31, 2001, we had $5.8 million in restricted cash required by the NYMEX commodity exchange to facilitate financial instrument and physical purchase transactions. This amount can fluctuate over time depending on the physical volumes underlying the contracts, market price of the commodity and type of transactions executed. During 2001, our restricted cash balance required by the exchange varied, reaching a peak of $13.4 million in July.

Consolidated cash flows for year ended December 31, 2000 compared to year ended December 31, 1999

Operating cash flows. Cash flows from operating activities were $360.9 million in 2000 compared to $177.9 million in 1999. After adjusting for changes in operating accounts which are generally the result of timing of sales and purchases near the end of each period, adjusted cash flow from operating activities increased $139.8 million to $289.8 million in 2000 compared to $150.0 million in 1999. The $139.8 million increase in adjusted cash flow from operating activities between periods is primarily due to the impact of the TNGL acquisition as discussed earlier under "Our results of operations - Year ended December 31, 2000 compared to year ended December 31, 1999."

Investing cash flows. We invested $268.8 million during 2000 (primarily in internal growth projects) compared to $271.2 million spent during 1999 (primarily for acquisitions). Fiscal 1999 reflects $208.1 million in net cash payments resulting from the TNGL and MBA acquisitions. Our capital expenditures increased substantially in 2000 over 1999 primarily due to the purchase of the Lou-Tex Propylene pipeline ($99.5 million) and construction costs related to the Lou-Tex NGL pipeline ($83.7 million).

Investments in and advances to unconsolidated affiliates during 1999 include our share of costs ($38.2 million) to complete construction and commence operations of the BRF facility and Wilprise and Tri-States pipelines. Our 2000 expenditures include $19.4 million paid to purchase an additional 8.4% interest in Dixie. The 1999 and 2000 amounts also include a combined $26.2 million in costs to construct the BRPC facility, which was completed in July 2000.

Financing cash flows. Our financing activities resulted in net cash payments of $36.9 million in 2000 versus net cash receipts of $74.4 million in 1999. Fiscal 2000 includes proceeds from the issuance of Senior Notes A and the MBFC Loan and the associated repayments on various bank credit facilities. Financing activities in 1999 include the borrowings under bank credit facilities to finance the TNGL and MBA acquisitions and $4.7 million paid by the Trust to repurchase (and treat as Treasury Units) 267,200 of our publicly-traded Common Units. Distributions to partners and the minority interest increased to $141.0 million in 2000 compared to $112.9 million in 1999 primarily due to increases in the quarterly distribution rate. Lastly, EPPLP repurchased and retired 28,400 Common Units during 2000 under its Buy-Back Program (see page 38) at a cost of $0.8 million.

Cash requirements for future growth

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 natural gas industry in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar disposal options. 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 well positioned to continue to grow through acquisitions that will expand its platform of assets and through internal growth projects. Our goal for fiscal 2002 is to invest at least $400 million in such opportunities that will be accretive to our investors.

The funds needed to achieve this goal can be attained through a combination of operating cash flows, debt or equity. During January and February 2002, we spent approximately $367.5 million to acquire hydrocarbon storage and propylene fractionation facilities and related assets from D-K. Of this amount, approximately $238.5 million was funded by a drawdown on our Multi-Year and 364-Day credit facilities leaving $161.5 million of unused commitments available under these credit agreements. The increase in outstanding debt will translate into additional debt service costs during 2002.

Another stated goal of management is to increase the distribution rate to our investors by at least 10% annually. At the end of 2001, the annual rate was $2.50 per Common Unit. We forecast that operating cash flows will be sufficient in 2002 to increase the rate to at least $2.75 per Common Unit (on a pre-split basis). On February 27, 2002, we announced an increase in the quarterly distribution from $0.625 per Common Unit to $0.67 per Common Unit on a pre-split basis. Based on the number of distribution-bearing Units projected to be outstanding during 2002, we project that this goal will translate into cash distributions increasing by approximately $50 million over the amounts paid to partners and the minority interest during 2001.

Future capital expenditures. During 2002, we forecast that approximately $79.3 million will be spent on expansion capital projects, of which $64.5 million is related to our Pipelines segment. In addition, we expect to spend $6.0 million on sustaining capital expenditures. We generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending on existing and new assets referred to as expansion capital expenditures. Both expansion and sustaining capital expenditures are recorded as cash outlays for property, plant and equipment. Maintenance, repairs and minor renewals are charged to operations as incurred. Our unconsolidated affiliates forecast a combined $62.2 million in capital expenditures during 2002 of which we will fund approximately $20.8 million.

The following table shows our projected capital spending by operating segment for 2002 (in thousands of dollars):

Operating Segment	Property, Plant And Equipment	Investments In Unconsolidated Affiliates	Total
	Expenditure Type		
Fractionation	$ 7,255	$ 7,929	$ 15,184
Pipelines	65,997	12,278	78,275
Processing	5,841		5,841
Octane Enhancement		560	560
Other	6,200		6,200
Total	$85,293	$20,767	$106,060

At December 31, 2001, we had $5.3 million in outstanding purchase commitments attributable to capital projects. Of this amount, $5.0 million is related to the construction of assets that will be recorded as property, plant and equipment and $0.3 million is associated with capital projects of our unconsolidated affiliates which will be recorded as additional investments.

New environmental regulations in the state of Texas may necessitate extensive redesign and modification of the our Mont Belvieu facilities to achieve the air emissions reductions needed for federal Clean Air Act compliance in the Houston-Galveston, Texas area. The technical practicality and economic reasonableness of these regulations have been challenged under state law in litigation filed on January 19, 2001, against the Texas Natural Resource Conservation Commission and its principal officials in the District Court of Travis County, Texas, by a coalition of major Houston-Galveston area industries including the Company. Until this litigation is resolved, the precise level of technology to be employed and the cost for modifying the facilities to achieve the required amount of reductions cannot be determined. Currently, the litigation has been stayed by agreement of the parties pending the outcome of expanded, cooperative scientific research to more precisely define sources and mechanisms of air pollution in the Houston-Galveston area. Completion of this research and formulation of the regulatory response are anticipated in mid-2002. Regardless of the results of this research and the outcome of the litigation, expenditures for air emissions reduction projects will be spread over several years, and we believe that adequate liquidity and capital resources will exist for us to undertake them. We have budgeted capital funds in 2002 to begin making modifications to certain Mont Belvieu facilities that will result in air emission reductions. The methods employed to achieve these reductions will be compatible with whatever regulatory requirements are eventually put in place. For additional information regarding the impact of the Clean Air Act on our operations, see page 22 of this report on Form 10-K.

Long-term debt

Our long-term debt consisted of the following at:

	December 31, 2001	December 31, 2000
Borrowings under:		
Senior Notes A, 8.25% fixed rate, due March 2005	$ 350,000	$ 350,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	
Total principal amount	854,000	404,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt (see Note 6 of Notes to Consolidated Financial Statements)	1,653	
Less unamortized discount on:		
Senior Notes A	(117)	(153)
Senior Notes B	(258)	
Less current maturities of long-term debt	-	
Long-term debt	$ 855,278	$ 403,847

Long-term debt does not reflect the $250 million Multi-Year Credit Facility or the $150 million 364-Day Credit Facility. No amount was outstanding under either of these two revolving credit facilities at December 31, 2001. See below for a complete description of these facilities.

At December 31, 2001, we had a total of $75 million of standby letters of credit capacity under our Multi-Year Credit Facility of which $2.4 million was outstanding.

We act as guarantor of certain debt obligations of our primary consolidated subsidiary, the Operating Partnership. This parent-subsidiary guaranty provision exists under our Senior Notes, MBFC Loan and two current revolving credit facilities. In the descriptions that follow, the term "MLP" denotes us in this guarantor role.

Senior Notes A. On March 13, 2000, we completed a public offering of $350 million in principal amount of 8.25% fixed-rate Senior Notes due March 15, 2005 at a price to the public of 99.948% per Senior Note (the "Senior Notes A"). These notes were issued to retire certain revolving credit loan balances that were created as a result of the TNGL acquisition and other general partnership activities.

The Senior Notes A are subject to a make-whole redemption right. The notes are an unsecured obligation and rank equally with existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness. The notes are guaranteed by the MLP through an unsecured and unsubordinated guarantee and were issued under an indenture containing certain restrictive covenants. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We were in compliance with these restrictive covenants at December 31, 2001.

Senior Notes B. On January 24, 2001, we completed a public offering of $450 million in principal amount of 7.50% fixed-rate Senior Notes due February 1, 2011 at a price to the public of 99.937% per Senior Note (the "Senior Notes B"). These notes were issued to finance the acquisition of Acadian Gas, Neptune, Nemo and Starfish; to cover construction costs of certain NGL pipelines and related projects; and to fund other general partnership activities.

The Senior Notes B were issued under the same indenture as Senior Notes A and therefore are subject to similar terms and restrictive covenants. The Senior Notes B are guaranteed by the MLP through an unsecured and unsubordinated guarantee. We were in compliance with the restrictive covenants at December 31, 2001.

MBFC Loan. On March 27, 2000, we executed a $54 million loan agreement with the Mississippi Business Finance Corporation ("MBFC") having a 8.70% fixed-rate and a maturity date of March 1, 2010. In general, the proceeds from this loan were used to retire certain revolving credit loan balances attributable to acquiring and constructing the Pascagoula, Mississippi natural gas processing facility.

The MBFC Loan is subject to a make-whole redemption right and is guaranteed by the MLP through an unsecured and unsubordinated guarantee. The indenture agreement contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable 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 in the indenture agreement) may, and if requested to do so by holders of at least 25% in aggregate of the principal amount of the outstanding underlying bonds, shall accelerate the maturity of the MBFC Loan, whereby the principal and all accrued interest would become immediately due and payable. If such an event occurred, we would have the option (a) to redeem the MBFC loan or (b) to provide an alternate credit agreement (as defined in the indenture agreement) to support our obligation under the MBFC loan, with both options exercisable within 120 days of receiving notice of the decline in our credit ratings from the ratings agencies.

The loan agreement contains certain covenants including maintaining appropriate levels of insurance on the Pascagoula facility and restrictions regarding mergers. We were in compliance with the restrictive covenants at December 31, 2001.

Multi-Year Credit Facility. On November 17, 2000, we entered into a $250 million five-year revolving credit facility that includes a sublimit of $75 million for letters of credit. The November 17, 2005 maturity date may be extended for one year at our option with the consent of the lenders, subject to the extension provisions in the agreement. We can increase the amount borrowed under this facility, with the consent of the Administrative Agent (whose consent may not be unreasonably withheld), up to an amount not exceeding $350 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders, so long as the aggregate amount of the funds borrowed under this credit facility and the 364-Day Credit Facility (described below) does not exceed $500 million. No lender will be required to increase its original commitment, unless it agrees to do so at its sole discretion. This credit facility is guaranteed by the MLP through an unsecured guarantee.

Proceeds from this credit facility will be used for working capital, acquisitions and other general partnership purposes. No borrowing was outstanding for this credit facility at December 31, 2001. In February 2002, we borrowed $200 million under this facility to complete our purchase of D-K's Mont Belvieu, Texas propylene fractionation assets.

Our obligations under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. As defined within the agreement, borrowings under this bank credit facility will generally bear interest at either (i) the greater of the Prime Rate or the Federal Funds Effective Rate plus one-half percent or (ii) a Eurodollar Rate plus an applicable margin or (iii) a Competitive Bid Rate. We elect the basis for the interest rate at the time of each borrowing.

Our credit agreement contains various affirmative and negative covenants to, among other things, (i) incur certain indebtedness, (ii) grant certain liens, (iii) enter into certain merger or consolidation transactions and (iv) make certain investments. In addition, we may not directly or indirectly make any distribution in respect of our partnership interests, except those payments in connection with the Buy-Back Program (not to exceed $30 million in the aggregate, see Note 7) and distributions from Available Cash from Operating Surplus, both as defined within the agreement.

The credit agreement also requires that we satisfy certain financial covenants at the end of each fiscal quarter. As defined within the agreement, we (i) must maintain Consolidated Net Worth of $750 million and (ii) not permit our ratio of Consolidated Indebtedness to Consolidated EBITDA, including pro forma adjustments (as defined within the agreement), for the previous four quarter period to exceed 4.0 to 1.0. If we fail to maintain these financial covenants, either the unused commitments under this facility will terminate or the outstanding principal balance (in whole or part at the discretion of the lenders) will be immediately payable or both. Since these ratios are dependent to a varying degree upon earnings, any sustained decline in our profitability would have a negative impact on these calculations. The Company was in compliance with the restrictive covenants at December 31, 2001.

364-Day Credit Facility. In conjunction with the Multi-Year Credit Agreement, we entered into a 364-day $150 million revolving bank credit facility. In November 2001, we and our lenders amended the revolving credit agreement to extend the maturity date to November 15, 2002 with an option to convert any revolving credit balance outstanding at November 15, 2002 to a one-year term loan.

We can increase the amount borrowed under this facility, with the consent of the Administrative Agent (whose consent may not be unreasonably withheld), up to an amount not exceeding $250 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders, so long as the aggregate amount of the funds borrowed under this credit facility and the Multi-Year Credit Facility do not exceed $500 million. No lender will be required to increase its original commitment, unless it agrees to do so at its sole discretion. This credit facility is guaranteed by the MLP through an unsecured guarantee. No borrowing was outstanding for this credit facility at December 31, 2001. In February 2002, we borrowed approximately $38.5 million under this facility to complete our purchase of D-K's Mont Belvieu, Texas propylene fractionation assets.

Our obligations under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. As defined within the agreement, borrowings under this bank credit facility will generally bear interest at either (i) the greater of the Prime Rate or the Federal Funds Effective Rate plus one-half percent or (ii) a Eurodollar Rate plus an applicable margin or (iii) a Competitive Bid Rate. We elect the basis for the interest rate at the time of each borrowing.

Proceeds from this credit facility will be used for working capital, acquisitions and other general partnership purposes. No amount was outstanding for this credit facility at December 31, 2001.

Limitations on certain actions by the Company and financial condition covenants of this bank credit facility are substantially consistent with those existing for the Multi-Year Credit Facility as described previously. We were in compliance with the restrictive covenants at December 31, 2001.

February 2001 Shelf

On February 23, 2001, we filed a $500 million universal shelf registration (the "February 2001 Shelf") covering the issuance of an unspecified amount of equity or debt securities or a combination thereof. We expect to use the net proceeds from any sale of securities for future business acquisitions and other general corporate purposes, such as working capital, investments in subsidiaries, the retirement of existing debt and/or the repurchase of Common Units or other securities. The exact amounts to be used and when the net proceeds will be applied to partnership purposes will depend on a number of factors, including our funding requirements and the availability of alternative funding sources. We routinely review acquisition opportunities.

For additional information regarding our debt, see Note 6 of the Notes to Consolidated Financial Statements beginning on page F-18 of this report on Form 10-K.

Summary of contractual obligations and material commercial commitments

The following table summarizes our contractual obligations and material purchase and other commitments for the periods shown (as of December 31, 2001):

Contractual Obligation Or Material Commercial Commitment	Total	2002	2003 Through 2005	2006 Through 2007	After 2007
Contractual Obligation (expressed in terms of millions of dollars payable per period:)					
Long-term debt	$ 854.0		$ 350.0		$ 504.0
Operating leases	$ 15.8	$ 5.1	$ 9.5	$ 0.3	$ 0.9
Capital spending:					
Property, plant and equipment	$ 5.0	$ 5.0			
Investments in unconsolidated affiliates	$ 0.3	$ 0.3			
Other commitments (expressed in terms of millions of dollars potentially payable per period):					
Letters of Credit under Multi-Year Credit Facility	$ 2.4		$ 2.4		
Other Material Contractual Obligations (Purchase commitments expressed in terms of minimum volumes under contract per period:)					
NGLs (MBbls)	28,530	9,588	18,602	340	
Natural gas (BBtus)	142,040	13,726	39,718	25,596	63,000

Long-term debt. Long-term debt includes our obligations under Senior Notes A and B and the MBFC Loan.

Operating leases. We lease certain equipment and processing facilities under noncancelable and cancelable operating leases. The amounts shown in the table represent minimum future rental payments due on such leases with terms in excess of one year.

The operating lease commitments shown above exclude the expense associated with various equipment leases contributed to us by EPCO at our formation for which EPCO has retained the liability. During 2001, 2000 and 1999, our non-cash lease expense associated with these EPCO "retained" leases was $10.4 million, $10.6 million and $10.6 million, respectively. Lease and rental expense (including Retained Leases) included in operating income for the years ended December 31, 2001, 2000 and 1999 was approximately $23.4 million, $21.2 million and $20.6 million. EPCO has assigned us the purchase options associated with the retained leases. Should we decide to exercise our purchase options under the retained leases, up to $26.0 million will be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016.

Capital spending. We have capital spending commitments attributable to various capital projects. Of this amount, $5.0 million is related to the construction of assets that will be recorded as property, plant and equipment and $0.3 million is associated with capital projects of our unconsolidated affiliates which will be recorded as additional investments.

NGL and natural gas purchase commitments. In addition, we have long-term purchase commitments for NGL products and related-streams (including natural gas) with several suppliers. The purchase prices contained within these contracts approximate market value at the time of delivery. Our purchase commitments for NGLs are stated in thousands of barrels and for natural gas in BBtus.

For additional information regarding our commitments, please see Note 11 of the Notes to Consolidated Financial Statements.

Impact of recent accounting developments

In June 2001, the FASB issued two new pronouncements: SFAS No. 141, "Business Combinations", and SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 141 prohibits the use of the pooling-of-interest method for business combinations initiated after June 30, 2001 and also applies to all business combinations accounted for by the purchase method that are completed after June 30, 2001. There are also transition provisions that apply to business combinations completed before July 1, 2001, that were accounted for by the purchase method. SFAS No. 142 became effective January 1, 2002 for all goodwill and other intangible assets recognized in our consolidated balance sheet at that date, regardless of when those assets were initially recognized. We adopted SFAS No. 141 on January 1, 2002.

Within six months our adoption of SFAS No. 142 (by June 30, 2002), we will have completed a transitional impairment review to identify if there is an impairment to the December 31, 2001 recorded goodwill or intangible assets of indefinite life using a fair value methodology. Professionals in the business valuation industry will be consulted to validate the assumptions used in such methodologies. Any impairment loss resulting from the transitional impairment test will be recorded as a cumulative effect of a change in accounting principle for the quarter ended June 30, 2002. Subsequent impairment losses will be reflected in operating income in the Statements of Consolidated Operations.

At January 1, 2002, our intangible assets included the values assigned to the 20-year Shell natural gas processing agreement (the "Shell agreement") and the excess cost of the purchase price over the fair market value of the assets acquired from Mont Belvieu Associates (the "MBA excess cost"), both of which were initially recorded in 1999. The value of the Shell agreement ($194.4 million net book value at December 31, 2001) is being amortized on a straight-line basis over its contract term. Likewise, the MBA excess cost ($7.9 million net book value at December 31, 2001) was being amortized on a straight-line basis over 20 years. Based upon initial interpretations of the new accounting standards, we anticipate that the intangible asset related to the Shell agreement will continue to be amortized over its contract term ($11.1 million annually for 2002 through July 2019); however, the MBA excess cost will be reclassified to goodwill in accordance with the new standard and its amortization will cease (currently, $0.5 million annually). This goodwill would then be subject to impairment testing as prescribed in SFAS No. 142. We are continuing to evaluate the comprehensive provisions of SFAS No. 142 and will fully adopt the standard during 2002 within the prescribed time periods.

In addition to SFAS No. 141 and No. 142, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations", in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for our fiscal year beginning January 1, 2003. We are continuing to evaluate the provisions of this statement. In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. We adopted this statement effective January 1, 2002 and determined that it will have no material impact on our financial statements as of that date.

Uncertainties regarding our investment in BEF

We have a 33.3% ownership interest in BEF, which owns a facility currently producing MTBE. The production of MTBE is driven by oxygenated fuels programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation. Any change to these 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 would reduce the demand for MTBE. In 1999, the Governor of California ordered the phase-out of MTBE in California by the end of

2002 due to allegations by several public advocacy and protest groups that MTBE contaminates water supplies, causes health problems and has not been as beneficial in reducing air pollution as originally contemplated. Subsequently, the EPA denied California's request for a waiver of the oxygenate requirement and the state is now reconsidering the timing of its MTBE ban.

Legislation introduced in the U.S. Senate would eliminate the Clean Air Act's oxygenate requirement in order to foster the elimination of MTBE in fuel by individual states such as California. Legislation introduced in the U.S. House to prevent states from banning MTBE was defeated in 2001. No assurance can be given as to whether the federal government or individual states will ultimately adopt legislation banning or promoting the use of MTBE as part of their clean air programs.

In light of these regulatory developments, the owners of BEF have been formulating a contingency plan for use of the BEF facility if MTBE were banned or significantly curtailed. Management is exploring a possible conversion of the BEF facility from MTBE production to alkylate production. 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 motor gasoline and that alkylate would be an attractive substitute. Depending upon the type of alkylate process chosen and the level of alkylate production desired, the cost to convert the facility from MTBE production to alkylate production would range from $20 million to $90 million, with our share of these costs ranging from $6.7 million to $30 million.

We issued the last installment of Special Units to Shell in August 2001

On or about June 30, 2001, Shell met certain year 2001 performance criteria for the issuance of the last installment of 3.0 million non-distribution bearing, convertible contingency Units (referred to as Special Units when issued). Under a contingent unit agreement with Shell executed as part of the 1999 TNGL acquisition, we issued these Special Units on August 2, 2001. The issuance of these new Special Units had an impact on diluted earnings per Unit beginning with the third quarter of 2001.

The value of these Special Units was determined to be $117.1 million using present value techniques. This amount increased the purchase price of the TNGL acquisition and the value of the Shell Processing Agreement when the additional Special Units were issued and recorded in August 2001. This amount also increased the equity position of Shell in the Company by $117.1 million with the General Partner contributing $1.2 million to maintain its respective ownership in the Company. The $117.1 million increase in value of the Shell Processing Agreement will be amortized over the remaining life of the contract. As a result, amortization expense will increase by approximately $6.5 million annually.

We converted a portion of Shell's Special Units into Common Units in August 2001

In accordance with existing agreements with Shell, 5.0 million of Shell's original issue of Special Units (issued in connection with the TNGL acquisition) converted into Common Units on August 2, 2001. The conversion had an impact on basic earnings per Unit and cash distributions to Shell beginning with the third quarter of 2001. Of the 14.5 million Special Units that remain outstanding at December 31, 2001, 9.5 million are scheduled to convert into Common Units in August 2002 with the balance of 5.0 million converting in August 2003.

Response to September 11, 2001 Terrorist Attacks

Following the recent 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 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 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.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We are exposed to financial market risks, including changes in commodity prices in our natural gas and NGL businesses and in interest rates with respect to a portion of our debt obligations. 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 in our Processing segment. In general, the types of risks hedged 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.

Apart from the disclosures below, additional information regarding our financial instruments (financial assets and liabilities) can be found under Note 13 in the Notes to Consolidated Financial Statements.

Commodity financial instruments. Our Processing and Octane Enhancement segments are directly exposed to commodity price risk through their respective business operations. The prices of natural gas, NGLs 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. These factors include the level of domestic oil, natural gas and NGL production and development, the availability of imported oil and natural gas, actions taken by foreign oil and natural gas producing nations, the availability of transportation systems with adequate capacity, the availability of alternative fuels and products, seasonal demand for oil, natural gas and NGLs, conservation, the extent of governmental regulation of production and the overall economic environment.

In order to manage the risks associated with our Processing segment, we may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The primary purpose of these risk management activities is to hedge exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. We do not hedge our exposure to the MTBE markets. Also, in our Pipelines segment, we may utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas and/or the price Acadian Gas pays for the natural gas it purchases.

We have adopted a commercial policy to manage our exposure to 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 levels 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 18 months). At December 31, 2001, we had open commodity financial instruments that settle at different dates through December 2002. The General Partner oversees our strategies associated with physical and financial risks, approves specific activities subject to the commercial policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

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

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

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

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

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

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

We routinely review our open 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 new commodity financial instruments to reestablish the hedge of the commodity position to which the closed instrument relates.

These commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 because of ineffectiveness. A hedge is normally regarded as effective if, among other things, at inception and throughout the term of the financial instrument, we could expect changes in the fair value of the hedged item to be almost fully offset by the changes in the fair value of the financial instrument. Currently, the majority of our commodity financial instruments do not qualify as effective accounting hedges under the guidelines of SFAS No. 133, with the result being that changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. The use of mark-to-market accounting for these commodity financial instruments results in a degree of non-cash earnings fluctuation that is dependent upon changes in the underlying commodity prices. Even though these instruments do not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133, we continue to view these financial instruments as economically hedging our commodity price risk exposure as this was the business intent when such contracts were executed. This characterization is consistent with the actual economic performance of the contracts to date and we expect these financial instruments to continue to mitigate (or offset) commodity price risk in the future. The specific accounting for these contracts, however, is consistent with the requirements of SFAS No. 133. For additional information regarding our commodity financial instruments, see Note 13 of the Notes to Consolidated Financial Statements.

Sensitivity Analysis for Commodity Financial Instruments Portfolio
Estimates of Fair Value ("FV") and Earnings Impact ("EI")
due to selected changes in quoted market prices at dates selected

Scenario	Resulting Classification	December 31, 2000	December 31, 2001	March 7, 2002
		(in millions of dollars)		
FV assuming no change in quoted market prices	Asset (Liability)	$ (38.6)	$ 5.6	$ (5.5)
FV assuming 10% increase in quoted market prices	Asset (Liability)	(56.3)	(0.3)	(18.4)
EI assuming 10% increase in quoted market prices	Income (Loss)	(17.7)	(5.9)	(12.9)
FV assuming 10% decrease in quoted market prices	Asset (Liability)	(20.9)	11.4	7.4
EI assuming 10% decrease in quoted market prices	Income (Loss)	17.7	5.8	12.9

At December 31, 2000, the fair value of the commodity financial instruments portfolio was a $38.6 million liability. At this date, our portfolio was primarily comprised of natural gas-based hedging instruments that were negatively affected by the unusually high natural gas prices that occurred at the end of 2000 and beginning of 2001. At December 31, 2001, the value of the financial instruments outstanding at that time reflected a $5.6 million asset primarily due to the moderation of natural gas prices. The portfolio value was also affected, to a lesser degree, by periodic changes in the composition of commodities hedged and settlements of certain open positions. At March 7, 2002, the value of the financial instruments outstanding at that time was a $5.5 million liability primarily due to an increase in natural gas prices.

Historical income or loss resulting from commodity hedging activities are a component of our operating costs and expenses as reflected in the Statements of Consolidated Operations. We recognized income of $101.3 million of such income during fiscal 2001, of which $95.7 million was realized through cash settlement of the commodity hedges.

Interest rate swaps. Our interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to the Senior Notes and MBFC Loan. We manage our exposure to changes in interest rates by utilizing interest rate swaps. The objective of holding 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. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount. We believe it is prudent to maintain an appropriate mixture of variable-rate and fixed-rate debt.

We assess interest rate cash flow risk by identifying and measuring changes in interest rate exposure that impact future cash flows and evaluating hedging opportunities. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis to estimate the expected changes in interest rates on future cash flows. The General Partner oversees the strategies associated with financial risks and approves instruments that are appropriate for our requirements.

Our interest rate swap agreements were dedesignated as hedging instruments after the adoption of SFAS No. 133; therefore, the swaps are accounted for on a mark-to-market basis. However, these financial instruments continue to be effective in achieving the risk management activities for which they were intended. As a result, the change in fair value of these instruments will be reflected on the balance sheet and in earnings (as a component of interest expense) using mark-to-market accounting.

At December 31, 2000, we had three interest rate swaps outstanding having a combined notional value of $154 million (attributable to fixed-rate debt) with an estimated fair value of $2.0 million (an asset). Due to the early termination of two of the swaps, the notional amount and fair value of the remaining swap was $54 million and $2.3 million (an asset), respectively, at December 31, 2001.

We recorded $13.2 million of income from our interest rates swaps during 2001 and $10.0 million during 2000. The income recognized in 2001 from these swaps includes the $2.3 million in non-cash mark-to-market income at December 31, 2001 (attributable to the sole remaining swap). The remaining $10.9 has been realized. No mark-to-market income was recorded prior to the implementation of SFAS No. 133.

The fair value of the remaining swap at December 31, 2001 would increase to $2.5 million if quoted market interest rates were to decline by 10%; conversely, the fair value would decline to $2.1 million if rates were to rise by 10%. For additional information regarding our interest rate swaps, see Note 13 of the Notes to Consolidated Financial Statements.

At December 31, 2001, our fixed-rate debt obligations aggregated $854.0 million principal amount and had a fair value of $894.0 million. Since these instruments are fixed interest rates, they do not expose us to risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase to approximately $920.6 million if the respective yields to maturity for these debt obligations were to decline by 10% from their levels at December 31, 2001. In general, such an increase in fair value would impact earnings and cash flows only if we elected to reacquire all or a portion of these instruments in the open market prior to their maturity.

Counterparty settlement risk issues

We are exposed to credit risk with our counterparties in terms of settlement risk associated with the financial instruments. On all transactions were we are exposed to settlement 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.

On December 2, 2001, Enron Corp., or Enron, (NYSE, symbol "ENE") announced that it and certain of its subsidiaries were filing voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy Court for the Southern District of New York. At the time of its bankruptcy filing, Enron North America, a subsidiary of Enron, was the counterparty to a number of our commodity financial instruments. As a result, we established a $10.6 million reserve 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. Of the reserve amount established, $4.3 million was attributable to various unbilled commodity financial instrument positions that terminate during the first quarter of 2002. Currently, we do not anticipate any material change in this estimate.

At December 31, 2001, receivables and other current assets associated with our counterparties totaled $9.9 million, net of the Enron reserve. Of the $9.9 million, $9.6 million is with counterparties rated as investment grade by prominent rating agencies.

Item 8. Financial Statements and Supplementary Data.

The information required hereunder is included in this report as set forth in the "Index to Financial Statements" on page F-1.

Item 9. Changes in and disagreements with Accountants on Accounting and Financial Disclosure.

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

As is commonly the case with publicly-traded master limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO (pursuant to the EPCO Agreement, see page 59) under the direction of the Board of Directors and executive officers of the General Partner.

Notwithstanding any limitation on its obligations or duties, our General Partner is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to the General Partner. Whenever possible, the General Partner intends to make any such indebtedness or other obligations non-recourse to it.

Audit and Conflicts Committee

In accordance with NYSE rules, the Board of Directors of the General Partner has named three of its members to serve on its Audit and Conflicts Committee. The members of the Audit and Conflicts Committee are financially literate and independent nonexecutive directors, free from any relationship that would interfere with the exercise of independent judgment. The Audit and Conflicts Committee has the authority to review specific matters as to which the Board of Directors believes there may be a conflict of interests in order to determine if the resolution of such conflict proposed by the General Partner is fair and reasonable to the Company. Any matters approved by the Audit and Conflicts Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by the General Partner or its Board of Directors of any duties they may owe us or our Unitholders.

The members of the Audit and Conflicts Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the committee shall have accounting or related financial management expertise. In addition to ruling in cases involving conflicts of interest, the primary responsibilities of the Audit and Conflicts Committee include:

- monitoring the integrity of the financial reporting process and its related systems of internal control;
- ensuring legal and regulatory compliance of the General Partner and the Company;
- overseeing the independence and performance of our independent public accountants;
- providing for an avenue of communication among the independent public accountants, management, internal audit function and the Board of Directors;
- encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;
- reviewing areas of potential significant financial risk to our businesses; and
- approving increases in the administrative service fee payable under the EPCO Agreement.

Pursuant to its formal written charter adopted in June 2000, the Audit and Conflicts committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to the independent public accountants as well as EPCO personnel. The Audit and Conflicts Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Directors, Executive Officers of the General Partner

Set forth below is the name, age and position of each of the directors and executive officers of the General Partner. Each member of the Board of Directors serves until such member's death, resignation or removal. The executive officers are elected for one-year terms and may be removed, with or without cause, only by the Board of Directors.

Name	Age	Position With General Partner
Dan L. Duncan (1,3)	69	Director and Chairman of the Board
O.S. Andras (1,3)	66	Director, President and Chief Executive Officer
Randa Duncan Williams (3)	40	Director
J. R. Eagan	47	Director
J. A. Berget (1)	49	Director
Dr. Ralph S. Cunningham (2)	61	Director
Curtis R. Frasier (1)	47	Director
Lee W. Marshall, Sr. (2)	69	Director
Richard S. Snell (2)	59	Director
Richard H. Bachmann (1,3)	49	Director, Executive Vice President, Chief Legal Officer and Secretary
Michael A. Creel (3)	48	Executive Vice President and Chief Financial Officer
A.J. ("Jim") Teague (3)	57	Executive Vice President
William D. Ray (3)	66	Executive Vice President
Charles E. Crain (3)	68	Senior Vice President
A. Monty Wells (3)	56	Senior Vice President
W. ("Bill") Ordemann (3)	42	Senior Vice President
Gil H. Radtke (3)	41	Senior Vice President
Michael J. Knesek (3)	47	Vice President and Principal Accounting Officer
W. Randall Fowler (3)	45	Vice President and Treasurer

(1) Member of the Executive Committee
(2) Member of the Audit and Conflicts Committee
(3) Executive Officer

Dan L. Duncan was elected Chairman of the Board and a Director of the General Partner in April 1998. Mr. Duncan has served as Chairman of the Board of our predecessor, EPCO, since 1979.

O.S. Andras was elected President, Chief Executive Officer and a Director of the General Partner in April 1998. Mr. Andras served as President and Chief Executive Officer of EPCO from 1996 to February 2001.

Randa Duncan Williams was elected a Director of the General Partner in April 1998. In February 2001, she was promoted to President and Chief Executive Officer of EPCO from her previous position of Group Executive Vice President of EPCO, a position she had held since 1994. Ms. Williams is the daughter of Dan L. Duncan.

J. R. (Jeri) Eagan was elected a Director of the General Partner in October 2000. Since 1999, Ms. Eagan has served in various executive-level positions with Shell and currently holds the office of Chief Financial Officer of Shell Oil Company in addition to that of Vice President Finance & Commercial Operations of a Shell subsidiary. From 1994 to 1999, she worked on several assignments in Shell's London office.

J.A. (Jorn) Berget was elected a Director of the General Partner in November 2000. Since 1995, Mr. Berget has served in various managerial positions with Shell, including Vice President and General Manager for one of its subsidiaries since 2000. Mr. Berget also serves as a director of Enventure Global Technologies (a joint venture between Shell and Halliburton Company).

Dr. Ralph S. Cunningham was elected a Director of the General Partner in April 1998. Dr. Cunningham retired in 1997 from Citgo Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995. Dr. Cunningham serves as a director of Tetra Technologies, Inc. (a publicly-traded energy services and chemicals company) and Agrium, Inc. (a Canadian publicly-traded agricultural chemicals company) and was a former director of EPCO from 1987 to 1997. Mr. Cunningham serves as Chairman of our Audit and Conflicts Committee.

Curtis R. Frasier was elected a Director of the General Partner in November 1999. Mr. Frasier has held various executive-level positions with Shell including President of its midstream enterprise business.

Lee W. Marshall, Sr. was elected a Director of the General Partner in April 1998. Mr. Marshall has been the Chief Executive Officer and principal owner of Bison Resources, LLC since 1991. He has also served in senior management positions with Union Pacific Resource and Tenneco Oil. Mr. Marshall is a member of our Audit and Conflicts Committee.

Richard S. Snell was elected a Director of the General Partner in June 2000. Mr. Snell was an attorney with Snell & Smith, P.C. for seven years after founding the firm in 1993. He is currently a partner with the law firm of Thompson & Knight LLP in Houston, Texas and is a certified public accountant. Mr. Snell is a member of our Audit and Conflicts Committee.

Richard H. Bachmann was elected a Director of the General Partner in June 2000. He has served as Executive Vice President and Chief Legal Officer of the General Partner and EPCO since January 1999. Previously, he was a partner with the legal firms of Snell & Smith P.C. and Butler & Binion.

Michael A. Creel was elected an Executive Vice President of the General Partner in February 2001, having served as a Senior Vice President of the General Partner since November 1999. In June 2000, Mr. Creel, a certified public accountant, assumed the role of Chief Financial Officer of the Company along with his other responsibilities. From 1997 to 1999 he held a series of positions with a Shell affiliate, including Senior Vice President, Chief Financial Officer and Treasurer. From 1995 to 1997, Mr. Creel was Vice President and Treasurer of NorAm Energy Corp.

A.J. ("Jim") Teague was elected an Executive Vice President of the General Partner in November 1999. From 1998 to 1999 he served as President of a Shell affiliate and from 1997 to 1998 was President of Marketing and Trading for Mapco, Inc..

William D. Ray was elected an Executive Vice President of the General Partner in April 1998. Mr. Ray has served as EPCO's Executive Vice President for Marketing and Supply since 1985.

Charles E. Crain was elected a Senior Vice President of the General Partner in April 1998. Mr. Crain has served as Senior Vice President of Operations for EPCO since 1991.

A. Monty Wells was elected a Senior Vice President of the General Partner in June 2000. Mr. Wells has served in a number of managerial positions with EPCO since 1980 including Vice President of Marketing and Supply.

W. ("Bill") Ordemann was elected a Senior Vice President of the General Partner in September 2001. Mr. Ordemann has served in executive-level positions in our NGL businesses since 1999. From 1996 to 1999, he served as a Vice President of two Shell affiliates, including TNGL.

Gil H. Radtke was elected a Senior Vice President of the General Partner in February 2002. Mr. Radtke joined the Company in connection with our purchase of Diamond-Koch's storage and propylene fractionation assets in January and February 2002. Before joining the Company, Mr. Radtke served as President of the Diamond-Koch joint venture where he was responsible for its storage, propylene fractionation, pipeline and NGL fractionation businesses. Mr. Radtke was employed by Valero Energy Corporation (a partner in the Diamond-Koch joint venture) for the last eighteen years in various commercial and analysis roles.

Michael J. Knesek was elected Principal Accounting Officer and a Vice President of the General Partner in August 2000. Since 1990, Mr. Knesek, a certified public accountant, has been the Controller and a Vice President of EPCO.

W. Randall Fowler was elected Treasurer and a Vice President of the General Partner in August 2000. Mr. Fowler joined the Company as director of investor relations in 1999. From 1995 to 1999, Mr. Fowler served in a number of corporate finance and accounting-related capacities at NorAm Energy Corp., including Director of Finance Wholesale Energy Marketing and Assistant Treasurer.

Section 16(a) Beneficial Ownership Reporting Compliance

Under the federal securities laws, the General Partner, the General Partner's directors, executive (and certain other) officers, and any persons holding more than ten percent of the Common Units are required to report their ownership of Common Units and any changes in that ownership to the Company and the SEC. Specific due dates for these reports have been established by regulation and the Company is required to disclose in this report any failure to file by these dates in 2001. The Company believes all of these filings were satisfied by the General Partner.

Due to administrative and record keeping errors in connection with Unit options issued by EPCO to certain officers and directors of the General Partner, Form 4 reports were filed in April 2001 by Richard H. Bachmann (one transaction), Charles E. Crain (one transaction), Michael A. Creel (one transaction), W. Randall Fowler (one transaction), Michael J. Knesek (one transaction), William D. Ray (one transaction) and A. Monty Wells (one transaction) with respect to being granted Unit options in February 2001, and a Form 4 report was filed in October 2001 by Richard S. Snell (one transaction) with respect to being granted Unit options in October 2000. Due to record keeping errors, a Form 4 Report was filed late in October 2001 by O.S. Andras in connection with open market purchases of our Common Units in September 2001(two transactions).

In April 2001 Form 4 reports were filed by Dan L. Duncan and EPCO with respect to the issuance of Unit options by EPCO to certain officers and directors of the General Partner in February 2001.

As of March 1, 2002, the Company believes that the General Partner and all of the General Partner's directors and officers and any ten percent holders are current in their filings.

Item 11. Executive Compensation.

We do not directly employ any of the persons responsible for managing or operating our businesses. Instead, our businesses are managed by the General Partner, the executive officers of which are employees of, and the compensation of whom is paid by, EPCO. In January 2000, we began reimbursing EPCO for our portion of the compensation EPCO pays individuals it employs as a result of our expansion activities (through the construction of new facilities, business acquisitions or the like). In addition, we pay EPCO an annual Administrative Services Fee to cover a portion of EPCO's total compensation costs for all other individuals it employs for the management and operation of our businesses. Currently, the Administrative Services Fee is $16.0 million annually (this amount is subject to a 10% escalation per year, if so approved by the Audit and Conflicts Committee). For a more complete discussion of the EPCO Agreement, including the Administrative Services Fee, see page 59.

The compensation of O.S. Andras, the General Partner's Chief Executive Officer, is paid solely by EPCO without any reimbursement by us. Of the EPCO employees serving our General Partner whose compensation is wholly or partially-reimbursed by us, the four most highly compensated (in terms of our reimbursement) at December 31, 2001 were A.J. ("Jim") Teague, W. ("Bill") Ordemann, William D. Ray and Charles E. Crain, collectively the "Named Executive Officers". The compensation of Mr. Ray and Mr. Crain is reimbursed to EPCO through our payment of the Administrative Services Fee. The compensation of Mr. Teague and Mr. Ordemann is wholly reimbursable by us apart from the Administrative Services Fee. The Named Executive Officers have also received certain equity-based awards as part of their compensation from EPCO, the expense of which awards are subject to reimbursement by us to the extent that an individual's compensation is not reimbursed as part of the Administrative Services Fee. As a result, we will be responsible for all of the costs associated with the awards granted to Mr. Teague and Mr. Ordemann. The cost of any awards granted to Mr. Ray and Mr. Crain will be covered by our payment of the Administrative Services Fee with EPCO solely bearing any shortfall in reimbursement.

The Administrative Services Fee paid to EPCO for the years ended December 31, 2001, 2000 and 1999 was $15.1 million, $13.8 million and $12.5 million. As noted above, this base amount partially reimbursed EPCO for the costs it incurred in managing and operating our businesses, including the compensation of Mr. Ray and Mr. Crain.

The following table sets forth certain compensation information for the reimbursable, expansion-related Named Executive Officers for the fiscal years ended December 31, 2001, 2000 and 1999. The information for Mr. Andras has been omitted since his compensation is wholly-paid by EPCO with no reimbursement by us. The information for Mr. Ray and Mr. Crain is not included since their compensation (along with other EPCO employees working on our behalf as discussed above) is fully reimbursed through the Administrative Services Fee.

Summary Compensation Table

		Annual Compensation		Long Term Compensation	
Name and Principal Position	Year	Salary	Bonus	Securities Underlying Options (#) (4)	All Other Compensation (5)
O. S. Andras,	2001	--	--	--	--
Chief Executive Officer (1)	2000	--	--	--	--
	1999	--	--	--	--
A. J. ("Jim") Teague,	2001	$ 344,970	$ 80,000	50,000	$10,275
Executive Vice President	2000	$ 322,500	$ 35,000	50,000	$10,200
	1999 (3)	n/a	n/a	50,000	n/a
William D. Ray,	2001	--	--	--	--
Executive Vice President (2)	2000	--	--	--	--
	1999	--	--	--	--
Charles E. Crain,	2001	--	--	--	--
Senior Vice President (2)	2000	--	--	--	--
	1999	--	--	--	--
W. ("Bill") Ordemann,	2001	$ 179,115	$160,000 (6)	20,000	$10,905
Senior Vice President	2000	$ 156,094	$ 15,000	--	$10,200
	1999 (3)	n/a	n/a	10,000	n/a

(1) The information for Mr. Andras has been omitted since his compensation is wholly-paid by EPCO with no reimbursement by us.
(2) The information for Mr. Ray and Mr. Crain is not included since their compensation is included in the Administrative Services Fee.
(3) Prior to January 1, 2000, EPCO waived its right to reimbursement from us for the compensation paid to employees that it had hired in connection with the expansion of our business. EPCO elected to charge us only the Administrative Services Fee during 1999; therefore, we did not bear the expense of reimbursement for the compensation of these individuals.
(4) Although EPCO waived its right to collect reimbursement for the base salaries, bonuses and other dollar compensation paid to the reimbursable, expansion-related Named Executive Officers in 1999 (see (3) above), these individuals received Common Unit Options that were not exercised/exercisable until after 1999. When the options are ultimately exercised, we will be responsible for reimbursing EPCO for expenditures associated with these awards.
(5) 2001 and 2000 amounts represent contributions made by EPCO to the 401(K) plan of the Named Executive Officers.
(6) Mr. Ordemann's 2001 bonuses include a $100,000 retention bonus agreed to when he joined us in connection with the TNGL acquisition.

Common Unit Option Grants During 2001

The following table provides certain information concerning individual grants of options to purchase Common Units during the fiscal year ended December 31, 2001 to each of the reimbursable, expansion-related Named Executive Officers.

Name	Number of Securities Underlying Options Granted (#)	% of Total Options Granted to Expansion Employees in Fiscal Year 2001	Exercise Price ($/Unit)	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Unit Price Appreciation for Option Term (1)	
					5% ($)	10% ($)
A. J. ("Jim") Teague	50,000	12.99%	$ 31.85	1/31/2010	$ 878,000	$ 2,162,500
W. ("Bill") Ordemann	20,000	5.19%	$ 31.85	1/31/2010	$ 351,200	$ 865,000

(1) The amounts shown under these columns are the result of calculations at the 5% and 10% rates required by the SEC and are not intended to forecast future appreciation of the Common Unit price.

Unit Options Exercised and Fiscal Year-End Values

The following table provides certain information concerning each exercise of options to purchase Common Units during the fiscal year ended December 31, 2001 by each of the reimbursable, expansion-related Named Executive Officers and the value of unexercised options as of December 31, 2001:

Name	Units Acquired Through Exercise of Options (#)	Value Realized ($) (1)	Number of Securities Underlying Unexercised Options at December 31, 2001		Value of Unexercised In-the-Money Options at December 31, 2001 (2)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
A. J. ("Jim") Teague	50,000	$ 1,137,500	--	100,000	$ --	$ 1,931,250
W. ("Bill") Ordemann	--	$ --	--	30,000	$ --	$ 594,500

(1) The "Value Realized" represents the difference between the exercise price of the Common Unit options and the market (sale) price of the Common Units on the date of exercise without considering any taxes which may have been owed.
(2) The value is based on $47.05 per Common Unit, which was the closing price reported on the NYSE on December 31, 2001.

Compensation of Directors

No additional compensation is paid to employees of EPCO or Shell who also serve as directors of the General Partner. During fiscal 2001, the three independent outside directors each received (i) an annual retainer of $18,000, (ii) $1,000 for each meeting of the Board of Directors that they attend and (iii) $500 for each meeting of the Audit and Conflicts Committee that they attend. In addition, an annual retainer of $500 is paid to each independent outside director who also serves as the chairman of a committee of the Board of Directors. These retainers and fees are an expense of the General Partner. The three independent outside directors have also been granted options to acquire Common Units. When these are exercised, the costs will be charged to the General Partner.

We have indemnified each director for his or her actions associated with being a director of the General Partner to the extent permitted under Delaware law.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

The following table sets forth certain information as of March 1, 2002, regarding the beneficial ownership of our Common, Subordinated and Special Units by (i) all persons known by the General Partner to beneficially own more than five percent of the Common Units, (ii) the directors and certain executive officers of the General Partner and (iii) all directors, executive and other officers of the General Partner as a group.

	Common Units		Subordinated Units		Special Units	
	Number Of Units	Percent Of Class	Number Of Units	Percent Of Class	Number Of Units	Percent Of Class
EPCO (1)	33,640,415	65.1%	21,409,870	100.0%	--	0.0%
Shell (2)	6,000,000	11.6%		0.0%	14,500,000	100.0%
Dan L. Duncan (1,3)	34,965,533	67.7%	21,409,870	100.0%	--	0.0%
O.S. Andras	1,220,600	2.4%	--	0.0%	--	0.0%
Randa Duncan Williams	--	0.0%	--	0.0%	--	0.0%
J. R. Eagan	--	0.0%	--	0.0%	--	0.0%
J. A. Berget	--	0.0%	--	0.0%	--	0.0%
Dr. Ralph S. Cunningham (4)	10,000	0.0%	--	0.0%	--	0.0%
Curtis R. Frasier	--	0.0%	--	0.0%	--	0.0%
Lee W. Marshall, Sr. (4)	10,000	0.0%	--	0.0%	--	0.0%
Richard S. Snell	3,100	0.0%	--	0.0%	--	0.0%
Richard H. Bachmann (5)	43,467	0.1%	--	0.0%	--	0.0%
Michael A. Creel	5,000	0.0%	--	0.0%	--	0.0%
A.J. Teague	26,080	0.1%	--	0.0%	--	0.0%
Charles E. Crain (6)	61,660	0.1%	--	0.0%	--	0.0%
All directors and executive officers as a group (19 persons) (7)	36,412,838	70.5%	21,409,870	100.0%	--	0.0%

(1) EPCO holds its Units through a wholly-owned subsidiary, EPC Partners II, Inc. Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the 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 Randa Duncan Williams, a director of the General Partner. The address of EPCO and Mr. Duncan is 2727 North Loop West, Houston, Texas 77008.
(2) The Special Units were issued to Shell US Gas & Power LLC (an affiliate of Shell) as part of the TNGL acquisition. The address for this affiliate of Shell is 1301 McKinney, Ste. 700, Houston, Texas 77010.

(3) In addition to the Units held by EPCO, Dan Duncan has beneficial ownership of an additional 1,625,118 Common Units held by the Enterprise Products 1998 Unit Option Plan Trust, Enterprise Products 2000 Rabbi Trust and the EPOLP 1999 Grantor Trust.
(4) Dr. Cunningham's and Mr. Marshall's beneficial ownership amounts represent options (under an EPCO Unit option plan) to purchase 10,000 Common Units within 60 days of March 21, 2002.
(5) Mr.Bachmann's beneficial ownership amount includes options (under an EPCO Unit option plan) to purchase 40,000 Common Units within 60 days of March 21, 2002.
(6) Mr.Crain's beneficial ownership amount includes options (under an EPCO Unit option plan) to purchase 20,000 Common Units within 60 days of March 21, 2002.
(7) Cumulatively, this group includes Common Unit options (under an EPCO Unit option plan) to purchase 129,061 Common Units within 60 days of March 21, 2002.

For a discussion of our Partners' Equity and Units in general, see Note 7 of the Notes to the Consolidated Financial Statements. Subordinated Units and Special Units are non-voting until their conversion in Common Units.

Item 13. Certain Relationships and Related 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 Duncan 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 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 Randa Duncan 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 the Company.

In addition, trust affiliates of EPCO (Enterprise Products 1998 Unit Option Plan Trust and the Enterprise Products 2000 Rabbi Trust) purchase Common Units for the purpose of granting options to certain directors of the General Partner, EPCO management and certain key employees. During 2001, these trusts purchased 211,518 Common Units on the open market or through privately negotiated transactions. At December 31, 2001, these trusts owned a total of 1,461,518 Common Units. In November 2001, EPCO directly purchased 500,000 Common Units at market prices for $22.6 million from our consolidated trust, EPOLP 1999 Grantor Trust, on behalf of a key executive and Director of the General Partner.

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 (in effect since July 1998). Under the terms of the EPCO Agreement, EPCO agreed 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 at cost (based upon EPCO's actual salary costs and related fringe benefits);
- 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 an irrevocable, non-exclusive worldwide license to all of the EPCO trademarks and trade names used our business;
- indemnify us against any losses resulting from certain lawsuits; and
- sublease 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 to us for one dollar per year and to assign its purchase option under such leases to us. EPCO remains liable for the lease payments associated with these assets.

Operating costs and expenses (as shown in the audited Statements of Consolidated Operations) treat the full amount of lease payments being made by EPCO as a non-cash operating expense (with the offset to Partners' Equity on the Consolidated Balance Sheet). In addition, operating costs and expenses include compensation charges for EPCO's employees who operate the facilities.

Pursuant to the EPCO Agreement, we reimburse EPCO for our portion of the costs of certain of its employees who manage our business and affairs. In general, our reimbursement of EPCO's expense associated with administrative positions that were active at the time of our initial public offering in July 1998 is capped by the Administrative Services Fee that we pay (currently at $16 million annually). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to annual 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 (including those associated with equity-based awards granted to certain individuals within this group) and the Administrative Services Fee will be retained by EPCO (i.e., EPCO solely bears any shortfall in reimbursement for this group).

Beginning in January 2000, we began reimbursing EPCO for our share of the compensation of administrative personnel that it had hired in response to our expansion and business development activities (through the construction of new facilities, business acquisitions or the like). EPCO began hiring "expansion" administrative personnel after our initial public offering in connection with the TNGL acquisition and other development activities. In general, we reimburse EPCO for our share of its compensation expense associated with these "expansion" administrative positions, including those costs attributable to equity-based awards.

The following table summarizes of the Administrative Services Fee paid to EPCO during the last three years. In addition, the table shows the total compensation reimbursed to EPCO for operations personnel and "expansion" administrative positions.

	For Year Ended December 31,		
	2001	2000	1999
	(in millions of dollars)		
Administrative Services Fee paid to EPCO	$ 15,125	$ 13,750	$ 12,500
Compensation reimbursed to EPCO	48,507	44,717	26,889
Total	$ 63,632	$ 58,467	$ 39,389

The Administrative Services Fee has increased each year from its initial $12.0 million per annum rate with the approval of the Audit and Conflicts Committee as prescribed in the EPCO Agreement. The increase in reimbursable compensation payments made to EPCO is primarily the result of the TNGL (1999) and Acadian Gas (2001) acquisitions. EPCO waived the reimbursement of "expansion" administrative personnel compensation through December 1999. As noted earlier, we began reimbursing EPCO for the employment costs of the "expansion" administrative employees beginning in January 2000, hence the significant increase for this line item in the table between 1999 and 2000.

We elected to prepay EPCO a discounted amount of $15.7 million for the 2002 Administrative Services Fee in December 2001 (the undiscounted amount was $16.0 million). We will owe EPCO for any undiscounted amount above the $16.0 million if the General Partner approves an increase in the fee during 2002.

Other related party transactions with EPCO or its affiliates

The following is a summary of the other ongoing significant relationships and transactions between us and EPCO and or its affiliates:

- EPCO is the operator of the plants and facilities owned by BEF and EPIK and is paid a management fee by these entities in lieu of reimbursement for the actual cost of providing management services. BEF and EPIK paid $0.8 million in management fees to EPCO during 2001.
- We have entered into an agreement with EPCO to provide trucking services to us for the loading and transportation of NGL products. During 2001, we paid $9.0 million for these services.
- In the normal course of business, we may, on occasion, engage in transactions with EPCO involving the buying and selling of NGL products. We did not record any such transactions with EPCO during 2001.

Relationships with Shell

We have an extensive and ongoing relationship with Shell as a partner, customer and vendor. Shell, through its subsidiary Shell US Gas & Power LLC, owns approximately 23.2% of our partnership interests and 30.0% of the General Partner. Currently, three members of the Board of Directors of the General Partner (J.R. Eagan, J.A. Berget and Curtis R. Frasier) are employees of Shell.

Shell is a significant customer of our Processing segment (see page 14 for a discussion of the 20-year Shell Processing Agreement). Apart from operating expenses arising from the Shell Processing Agreement, the Company also sells NGL and petrochemical products to Shell. During 2001, revenues from Shell aggregated $333.3 million while purchases from Shell totaled $705.4 million.

Shell accounted for 10.5% of consolidated revenues in 2001 (up from 9.5% of consolidated revenues in 2000). Approximately 80% of our revenues from Shell during 2001 and 2000 are attributable to the sale of NGL products as recorded in our Processing segment. See Note 10 of the Notes to the Consolidated Financial Statements for additional information regarding related party transactions.

In April 2001, we acquired Acadian Gas from Shell from approximately $226 million in an arms-length negotiated transaction (through a bidding process) that was approved by the Board of Directors of the General Partner, with the three Shell representatives abstaining. See page 8 for a discussion of the assets involved in this acquisition.

In January 2001, we purchased equity interests in four Gulf of Mexico natural gas pipeline systems (Stingray, Manta Ray, Nautilus and Nemo) from El Paso. Shell also owns equity interests in and operates and/or administers each of these pipelines. During 2001, our portion of the management and operating fees for these pipeline systems paid to Shell was $0.8 million. See page 8 for a more detailed discussion of these pipeline systems.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K.

(a)(1) and (2) Financial Statements and Financial Statement Schedules

See "Index to Financial Statements" set forth on page F-1.

(a)(3) Exhibits

2.1 Purchase and Sale Agreement between Coral Energy, LLC and Enterprise Products Operating L.P. dated as of September 22, 2000. (Exhibit 10.1 to Form 8-K filed on September 26, 2000).

2.2 Purchase and Sale Agreement dated as of January 16, 2002 by and between Diamond-Koch, L.P. and Diamond-Koch III, L.P. and Enterprise Products Texas Operating L.P. (Exhibit 10.1 to Form 8-K filed February 8, 2002).

2.3 Purchase and Sale Agreement dated as of January 31, 2002 by and between D-K Diamond-Koch, L.L.C., Diamond-Koch, L.P. and Diamond-Koch III, L.P. as Sellers, and Enterprise Products Operating L.P., as Buyer. (Exhibit 10.2 to Form 8-K filed February 8, 2002).

3.1 Form of Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. (Exhibit 3.2 to Registration Statement of Form S-1/A, File No. 333-52537, filed on July 21, 1998).

3.2 Second Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated September 17, 1999. (The Company incorporates by reference the above document included as Exhibit "D" to the Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).

3.3 First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated September 17, 1999. (Exhibit 99.8 on Form 8-K/A-1 filed October 27, 1999).

3.4 Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated June 9, 2000. (Exhibit 3.6 to Form 10-Q filed August 11, 2000).

4.1 Form of Common Unit certificate. (Exhibit 4.1 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 21, 1998).

4.2 Unitholder Rights Agreement among Tejas Energy LLC, Tejas Midstream Enterprises, LLC, Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products Company, Enterprise Products GP, LLC and EPC Partners II, Inc. dated September 17, 1999. (The Company incorporates by reference the above document included as Exhibit "C" to the Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).

4.3 Contribution Agreement by and among Tejas Energy LLC, Tejas Midstream Enterprises, LLC, Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products Company, Enterprise Products GP, LLC and EPC Partners II, Inc. dated September 17, 1999. (The Company incorporates by reference the above document included as Exhibit "B" to the Schedule 13 D filed September 27, 1999 by Tejas Energy, LLC).

4.4 Registration Rights Agreement between Tejas Energy LLC and Enterprise Products Partners L.P. dated September 17, 1999. (The Company incorporates by reference the above document included as Exhibit "E" to the Schedule 13 D filed September 27, 1999 by Tejas Energy, LLC).

4.5 Form of Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee. (Exhibit 4.1 on Form 8-K filed March 10, 2000).

4.6 Form of Global Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (the "Senior Notes A"). (Exhibit 4.2 on Form 8-K filed March 10, 2000).

4.7 $250 million Multi-Year Revolving Credit Agreement (the "Multi-Year Credit Facility") among Enterprise Products Operating L.P., First Union National Bank, as administrative agent; Bank One, NA, as documentation agent; and The Chase Manhattan Bank, as syndication agent and the Several Banks from time to time parties thereto dated November 17, 2000. (Exhibit 4.2 on Form 8-K filed January 25, 2001).

4.8 $150 Million 364-Day Revolving Credit Agreement (the "364-Day Credit Facility") among Enterprise Products Operating L.P. and First Union National Bank, as administrative agent; Bank One, NA, as documentation agent; and The Chase Manhattan Bank, as syndication agent and the Several Banks from time to time parties thereto dated November 17, 2000. (Exhibit 4.3 on Form 8-K filed January 25, 2001).

4.9 Guaranty Agreement (relating to the Multi-Year Credit Facility) by Enterprise Products Partners L.P. in favor of First Union National Bank, as administrative agent dated November 17, 2000. (Exhibit 4.4 on Form 8-K filed January 25, 2001).

4.10 Guaranty Agreement (relating to the 364-Day Credit Facility) by Enterprise Products Partners L.P. in favor of First Union National Bank, as administrative agent dated November 17, 2000. (Exhibit 4.5 on Form 8-K filed January 25, 2001).

4.11 Form of Global Note representing $450 million principal amount of 7.50% Senior Notes due 2011 (the "Senior Notes B"). (Exhibit 4.1 to Form 8-K filed January 25, 2001).

4.12 First Amendment to Multi-Year Credit Facility dated April 19, 2001. (Exhibit 4.12 to Form 10-Q filed May 14, 2001).

4.13*First Amendment to 364-Day Credit Facility dated November 6, 2001, effective as of November 16, 2001.

10.1 Articles of Merger of Enterprise Products Company, HSC Pipeline Partnership, L.P., Chunchula Pipeline Company, LLC, Propylene Pipeline Partnership, L.P., Cajun Pipeline Company, LLC and Enterprise Products Texas Operating L.P. dated June 1, 1998. (Exhibit 10.1 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 8, 1998).

10.2 Form of EPCO Agreement among Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products Company. (Exhibit 10.2 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 21, 1998).

10.3 Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998. (Exhibit 10.3 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 8, 1998).

10.4 Venture Participation Agreement among Sun Company, Inc. (R&M), Liquid Energy Corporation and Enterprise Products Company dated May 1, 1992. (Exhibit 10.4 to Registration Statement on Form S-1, File No. 333-52537, filed on May 13, 1998).

10.5 Partnership Agreement among Sun BEF, Inc., Liquid Energy Fuels Corporation and Enterprise Products Company dated May 1, 1992. (Exhibit 10.5 to Registration Statement on Form S-1, File No. 333-52537, filed on May 13, 1998).

10.6 Amended and Restated MTBE Off-Take Agreement between Belvieu Environmental Fuels and Sun Company, Inc. (R&M) dated August 16, 1995. (Exhibit 10.6 to Registration Statement on Form S-1, File No. 333-52537, filed on May 13, 1998).

10.7 Propylene Facility and Pipeline Agreement between Enterprise Petrochemical Company and Hercules Incorporated dated December 13, 1978. (Exhibit 10.9 to Registration Statement on Form S-1, File No. 333-52537, filed on May 13, 1998).

10.8 Restated Operating Agreement for the Mont Belvieu Fractionation Facilities Chambers County, Texas among Enterprise Products Company, Texaco Producing Inc., El Paso Hydrocarbons Company and Champlin Petroleum Company dated July 17, 1985. (Exhibit 10.10 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 8, 1998).

10.9 Ratification and Joinder Agreement relating to Mont Belvieu Associates Facilities among Enterprise Products Company, Texaco Producing Inc., El Paso Hydrocarbons Company, Champlin Petroleum Company and Mont Belvieu Associates dated July 17, 1985. (Exhibit 10.11 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 8, 1998).

10.10 Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1993. (Exhibit 10.12 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 8, 1998).

10.11 Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1995. (Exhibit 10.13 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 8, 1998).

10.12 Fourth Amendment to Conveyance of Gas Processing Rights among Tejas Natural Gas Liquids, LLC and Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Deepwater Development Inc., Shell Land & Energy Company and Shell Frontier Oil & Gas Inc. dated August 1, 1999. (Exhibit 10.14 to Form 10-Q filed on November 15, 1999).

10.13 Fifth Amendment to Conveyance of Gas Processing Rights dated as of April 1, 2001 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore, Inc., Shell Consolidated Energy Resources, Inc., Shell Land & Energy Company and Shell Frontier Oil & Gas, Inc. (Exhibit 10.13 to Form 10-Q filed on August 13, 2001).

10.14 Enterprise Products Company 1998 Long-Term Incentive Plan (Exhibit 10.1 to Registration Statement on Form S-8, File No. 333-36856, filed on May 12, 2000).

10.15 Enterprise Products GP, LLC 1999 Long-Term Incentive Plan (Exhibit 10.2 to Registration Statement on Form S-8, File No. 333-36856, filed on May 12, 2000).

10.16 Form of Option Agreement under the 1998 Long-Term Incentive Plan and the 1999 Long-Term Incentive Plan (Exhibit 10.3 to the Registration Statement on Form S-8, File No. 333-36856, filed on May 12, 2000).

12.1* Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2001, 2000, 1999, 1998 and 1997.

21.1* List of subsidiaries.

23.1* Consent of Deloitte & Touche.

* An asterisk indicates that an exhibit is filed in conjunction with this report. All other documents are incorporated by reference as indicated in their descriptions.

(b) Reports on Form 8-K

Form 8-K filed November 13, 2001. In accordance with Regulation FD, we notified our investors and the SEC that representatives of our General Partner were to make a presentation to equity analysts and others on November 13, 2001 concerning the Company. We noted that interested parties could view the presentation materials on our website, www.epplp.com

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INDEX TO FINANCIAL STATEMENTS

All schedules, except the one listed above, have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

Independent Auditors' Report

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, 2001 and 2000, and the related statements of consolidated operations, consolidated cash flows and consolidated partners' equity for each of the years in the three-year period ended December 31, 2001. Our audits also included the consolidated financial statement schedule of the Company listed in the Index to the Financial Statements. These consolidated financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and schedule 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, 2001 and 2000, and the results of its consolidated operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 13 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments in 2001.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 8, 2002

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

ASSETS	December 31, 2001	December 31, 2000
Current Assets		
Cash and cash equivalents (includes restricted cash of $5,752 at December 31, 2001)	$ 137,823	$ 60,409
Accounts receivable - trade, net of allowance for doubtful accounts of $20,642 at December 31, 2001 and $10,916 at December 31, 2000	256,927	409,085
Accounts receivable - affiliates	4,375	6,533
Inventories	69,443	93,222
Prepaid and other current assets	50,207	12,107
Total current assets	518,775	581,356
Property, Plant and Equipment, Net	1,306,790	975,322
Investments in and Advances to Unconsolidated Affiliates	398,201	298,954
Intangible assets, net of accumulated amortization of $13,084 at December 31, 2001 and $5,374 at December 31, 2000	202,226	92,869
Other Assets	5,201	2,867
Total	$ 2,431,193	$ 1,951,368
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable - trade	$ 54,269	$ 96,559
Accounts payable - affiliates	29,885	56,447
Accrued gas payables	233,536	377,126
Accrued expenses	22,460	21,488
Accrued interest	24,302	10,068
Other current liabilities	44,764	24,691
Total current liabilities	409,216	586,379
Long-Term Debt	855,278	403,847
Other Long-Term liabilities	8,061	15,613
Minority Interest	11,716	9,570
Commitments and Contingencies		
Partners' Equity		
Common Units (51,360,915 Units outstanding at December 31, 2001 and 46,257,315 at December 31, 2000)	651,872	514,896
Subordinated Units (21,409,870 Units outstanding at December 31, 2001 and December 31, 2000)	193,107	165,253
Special Units (14,500,000 Units outstanding at December 31, 2001 and 16,500,000 at December 31, 2000)	296,634	251,132
Treasury Units acquired by Trust, at cost (163,600 Common Units outstanding at December 31, 2001 and 267,200 at December 31, 2000)	(6,222)	(4,727)
General Partner	11,531	9,405
Total Partners' Equity	1,146,922	935,959
Total	$ 2,431,193	$ 1,951,368

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in thousands, except per Unit amounts)

	For Year Ended December 31,		
	2001	2000	1999
REVENUES			
Revenues from consolidated operations	$ 3,154,369	$ 3,049,020	$ 1,332,979
Equity income in unconsolidated affiliates	25,358	24,119	13,477
Total	3,179,727	3,073,139	1,346,456
COST AND EXPENSES			
Operating costs and expenses	2,861,743	2,801,060	1,201,605
Selling, general and administrative	30,296	28,345	12,500
Total	2,892,039	2,829,405	1,214,105
OPERATING INCOME	287,688	243,734	132,351
OTHER INCOME (EXPENSE)			
Interest expense	(52,456)	(33,329)	(16,439)
Interest income from unconsolidated affiliates	31	1,787	1,667
Dividend income from unconsolidated affiliates	3,462	7,091	3,435
Interest income - other	7,029	3,748	886
Other, net	(1,104)	(272)	(379)
Other income (expense)	(43,038)	(20,975)	(10,830)
INCOME BEFORE MINORITY INTEREST	244,650	222,759	121,521
MINORITY INTEREST	(2,472)	(2,253)	(1,226)
NET INCOME	$ 242,178	$ 220,506	$ 120,295
ALLOCATION OF NET INCOME TO:			
Limited partners	$ 236,570	$ 217,909	$ 119,092
General partner	$ 5,608	$ 2,597	$ 1,203
BASIC EARNINGS PER UNIT			
Income before minority interest	$ 3.43	$ 3.28	$ 1.80
Net income per Common and Subordinated unit	$ 3.39	$ 3.25	$ 1.79
DILUTED EARNINGS PER UNIT			
Income before minority interest	$ 2.80	$ 2.67	$ 1.65
Net income per Common, Subordinated and Special unit	$ 2.77	$ 2.64	$ 1.64

See Notes to Consolidated Financial Statements

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

	For Year Ended December 31,		
	2001	2000	1999
OPERATING ACTIVITIES			
Net income	$ 242,178	$ 220,506	$ 120,295
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:			
Depreciation and amortization	51,903	41,045	25,315
Equity in income of unconsolidated affiliates	(25,358)	(24,119)	(13,477)
Distributions received from unconsolidated affiliates	45,054	37,267	6,008
Leases paid by EPCO	10,309	10,537	10,557
Minority interest	2,472	2,253	1,226
Loss (gain) on sale of assets	(390)	2,270	123
Changes in fair market value of financial instruments (see Note 13)	(5,697)		
Net effect of changes in operating accounts	(37,143)	71,111	27,906
Operating activities cash flows	283,328	360,870	177,953
INVESTING ACTIVITIES			
Capital expenditures	(149,896)	(243,913)	(21,234)
Proceeds from sale of assets	568	92	8
Business acquisitions, net of cash received	(225,665)		(208,095)
Collection of notes receivable from unconsolidated affiliates		6,519	19,979
Investments in and advances to unconsolidated affiliates	(116,220)	(31,496)	(61,887)
Investing activities cash flows	(491,213)	(268,798)	(271,229)
FINANCING ACTIVITIES			
Long-term debt borrowings	449,717	598,818	350,000
Long-term debt repayments		(490,000)	(154,923)
Debt issuance costs	(3,125)	(4,043)	(3,135)
Cash distributions paid to partners	(164,308)	(139,577)	(111,758)
Cash distributions paid to minority interest by Operating Partnership	(1,687)	(1,429)	(1,140)
Unit repurchased and retired		(770)	
Cash contributions from EPCO to minority interest	105	108	86
Treasury Units purchased by Trust	(18,003)		(4,727)
Treasury Units reissued by Trust	22,600		
Increase in restricted cash	(5,752)		
Financing activities cash flows	279,547	(36,893)	74,403
NET CHANGE IN CASH AND CASH EQUIVALENTS	71,662	55,179	(18,873)
CASH AND CASH EQUIVALENTS, JANUARY 1	60,409	5,230	24,103
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 132,071	$ 60,409	$ 5,230

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(Dollars in thousands)

	Limited Partners					
	Common Units	Subord. Units	Special Units	Treasury Units	General Partner	Total
Balance, December 31, 1998	$ 433,082	$ 123,829			$ 5,625	$ 562,536
Net income	80,998	38,094			1,203	120,295
Leases paid by EPCO	7,109	3,342			106	10,557
Special Units issued to Shell in connection with TNGL acquisition			$210,436		2,126	212,562
Cash distributions to Unitholders	(81,993)	(28,647)			(1,118)	(111,758)
Treasury Units acquired by consolidated Trust				$ (4,727)		(4,727)
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
Additional Special Units issued to Shell in connection with contingency agreement			55,241		557	55,798
Conversion of 1.0 million Shell Special Units into Common Units	14,513		(14,513)			--
Units repurchased and retired in connection with buy-back program	(687)	(43)	(32)		(8)	(770)
Cash distributions to Unitholders	(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
Additional Special Units issued to Shell in connection with contingency agreement			117,066		1,183	118,249
Conversion of 5.0 million Shell Special Units into Common Units	72,554		(72,554)			
Cash distributions to Unitholders	(109,969)	(49,510)			(4,829)	(164,308)
Treasury Units acquired by consolidated Trust				(18,003)		(18,003)
Treasury Units reissued by consolidated Trust				16,508		16,508
Gain on reissuance of Treasury Units by consolidated Trust	3,518	1,461	990		61	6,030
Balance, December 31, 2001	$ 651,872	$ 193,107	$296,634	$ (6,222)	$ 11,531	$ 1,146,922

See Notes to Consolidated Financial Statements

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ENTERPRISE PRODUCTS PARTNERS L.P. including its consolidated subsidiaries is a publicly-traded Delaware limited partnership listed on the New York Stock Exchange under symbol "EPD". Unless the context requires otherwise, references to "we","us","our" or the "Company" 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 12,000,000 Common Units. The Common Units sold for $22 per unit. We received approximately $243.3 million net of underwriting commissions and offering costs.

The accompanying consolidated financial statements include the historical accounts and operations of the NGL business of EPCO, including NGL operations conducted by affiliated companies of EPCO prior to their consolidation with EPCO. The consolidated financial statements include our accounts and those of our majority-owned subsidiaries, after elimination of all material intercompany accounts and transactions. In general, 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.

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.

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.

FINANCIAL INSTRUMENTS such as swaps, forwards and other contracts to manage the price risks associated with inventories, firm commitments and certain anticipated transactions are used by the Company. We are required to recognize in earnings changes in fair value of these financial instruments that are not offset by changes in the fair value of the inventories, firm commitments and certain anticipated transactions. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale.

The effective portion of these hedged transactions will be deferred until the firm commitment or anticipated transaction affects 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 that exposure and meet the hedging requirements of SFAS No. 133. Any contracts held or issued that do not meet the requirements of a hedge (as defined by SFAS No. 133) will be recorded at fair value on the balance sheet and any changes in that fair value recognized in earnings (using mark-to-market accounting). A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

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. See Notes 7 and 8 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, 2001 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated $1.3 million, $1.3 million and $0.9 million for the years ended December 31, 2001, 2000 and 1999, 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 K/D/S Promix L.L.C., Dixie Pipeline Company, Neptune Pipeline Company L.L.C. and Nemo Pipeline Company, LLC. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities. See Note 4 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 inventory, and volumes loaned to us under such agreements are accrued as a liability in accrued gas payables.

FEDERAL INCOME TAXES are not provided because we are a master limited partnership. As a result, our earnings or losses for Federal income tax purposes are included in the tax returns of the individual partners. Accordingly, no recognition has been given to income taxes in our financial statements. State income taxes are not material to us. 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.

INVENTORIES are valued at the lower of average cost or market (normal trade inventories of natural gas, NGLs and petrochemicals) or using specific identification (volumes dedicated to forward sales contracts).

INTANGIBLE ASSETS include the values assigned to a 20-year natural gas processing agreement and the excess cost of the purchase price over the fair market value of the assets acquired from Mont Belvieu Associates (the "MBA excess cost"), both of which were initially recorded in 1999. Of the intangible values at December 31, 2001, $194.4 million is assigned to the natural gas processing agreement and is being amortized on a straight-line basis over the contract term.

The remaining $7.9 million balance of intangibles relates to the MBA excess cost which has been amortized on a straight-line basis over 20 years. Upon adoption of SFAS No. 142 on January 1, 2002, this amount was reclassified to goodwill and will no longer be amortized but will be subject to periodic impairment testing in accordance with the new standard. For additional information regarding this reclassification and other details pertaining to the adoption of SFAS No. 142, see Note 5.

LONG-LIVED ASSETS 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.

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, and 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 referred to as expansion capital expenditures.

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, 2001, cash and cash equivalents includes $5.8 million of restricted cash related to these requirements.

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. 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.

In our Fractionation segment, we enter into NGL fractionation, isomerization and propylene fractionation tolling arrangements, NGL fractionation in-kind contracts and propylene fractionation merchant contracts. Under our tolling arrangements, we recognize revenue once contract services have been performed. These tolling arrangements typically include a base processing fee per gallon subject to adjustment for changes in natural gas, electricity and labor costs, which are the principal variable costs of fractionation and isomerization operations. At our Norco NGL fractionation facility, certain tolling arrangements involves the retention of a contractually-determined percentage of the NGLs produced for the processing customer in lieu of a cash tolling fee per gallon (i.e., an "in-kind" fee). We recognize revenue from these in-kind contracts when we sell (at market-related prices) and deliver the NGLs retained by our fractionator to customers. In our propylene fractionation merchant contracts, we recognize revenue once the products have been delivered to the customer. These merchant contracts are based upon market-related prices as determined by the individual contracts.

In our Pipelines segment, we enter into pipeline, storage and product loading contracts. Under our liquids pipeline 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 the Federal Energy Regulatory Commission ("FERC"). Additionally, we have merchant contracts associated with our natural gas pipeline business whereby revenue is recognized once a quantity of natural gas has been delivered to a customer. These merchant contracts are based upon market-related prices as determined by the individual contracts.

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 loading contracts (applicable to EPIK, an unconsolidated affiliate of the Company) are recorded once the loading services have been performed with the loading rates stated in the individual contracts.

As part of our Processing business, we have entered into a significant 20-year natural gas processing agreement with Shell ("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 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 contract stipulates that we retain a percentage of the NGLs extracted as payment for its services, revenue is recorded when the NGLs are sold and delivered to third parties. The Processing segment's merchant activities may also buy and sell NGLs in the open market (including forward sales contracts). The revenues recorded for these contracts are recognized upon the delivery of the products specified in each individual contract. Pricing under both types of arrangements is based upon market-related prices plus or minus other determining factors specific to each contract such as location pricing differentials.

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. 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. Revenue is recognized once the product has been delivered to Sun.

The Other segment is primarily comprised of 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 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. BUSINESS ACQUISITIONS

Acquisition of Acadian Gas in April 2001

On April 2, 2001, we acquired Acadian Gas from an affiliate of Shell, for approximately $226 million in cash using proceeds from the issuance of the $450 million Senior Notes B (see Note 6). Acadian Gas is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. Its assets are comprised of the 438-mile Acadian and 577-mile Cypress natural gas pipelines and a leased natural gas storage facility. Acadian Gas owns an approximate 49.5% of Evangeline which owns a 27-mile natural gas pipeline. We operate the systems. Overall, the Acadian Gas and Evangeline systems are comprised of 1,042 miles of pipeline with an optimal design capacity of 1.1 Bcf/d.

The Acadian Gas and Evangeline systems link supplies of natural gas from Gulf of Mexico production (through connections with offshore pipelines) and various onshore developments to industrial, electrical and local distribution customers primarily located in Louisiana. In addition, these systems have interconnects with twelve interstate and four intrastate pipelines and a bi-directional interconnect with the U.S. natural gas marketplace at the Henry Hub.

The Acadian Gas acquisition was accounted for under the purchase method of accounting and, accordingly, the initial purchase price has been allocated to the assets acquired and liabilities assumed based on their estimated fair values at April 1, 2001 as follows (in millions):

Current assets	$ 83,123
Investments in unconsolidated affiliates	2,723
Property, plant and equipment	225,169
Current liabilities	(83,890)
Other long-term liabilities	(1,460)
Total purchase price	$ 225,665

The balances related to the Acadian Gas acquisition included in the consolidated balance sheet dated December 31, 2001 are based upon preliminary information and are subject to change as additional information is obtained. The initial purchase price is subject to certain post-closing adjustments attributable to working capital items and is expected to be finalized during the first half of 2002.

Historical information for periods prior to April 1, 2001 do not reflect any impact associated with the Acadian Gas acquisition.

Pro forma effect of business combinations

The following table presents selected unaudited pro forma information for the years ended December 31, 2001 and 2000 as if the acquisition of Acadian Gas had been made as of the beginning of the years presented. This table also incorporates selected unaudited pro forma information for the year ended December 31, 2000 relating to our equity investments in Starfish and Neptune (see Note 4).

The pro forma information is based upon data currently available to and certain estimates and assumptions by management and, as a result, are 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.

	For Year Ended December 31,	
	2001	2000
Revenues	$3,391,654	$3,673,049
Income before extraordinary item and minority interest	$ 248,934	$ 217,223
Net income	$ 246,419	$ 215,026
Allocation of net income to		
Limited partners	$ 240,745	$ 212,483
General Partner	$ 5,674	$ 2,542
Units used in earnings per Unit calculations		
Basic	69,726	67,108
Diluted	85,393	82,444
Income per Unit before minority interest		
Basic	$ 3.49	$ 3.20
Diluted	$ 2.85	$ 2.60
Net income per Unit		
Basic	$ 3.45	$ 3.17
Diluted	$ 2.82	$ 2.58

3. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation are as follows:

	Estimated Useful Life In Years	2001	2000
Plants and pipelines	5-35	$1,398,843	$1,108,519
Underground and other storage facilities	5-35	127,900	109,760
Transportation equipment	3-35	3,736	2,620
Land		15,517	14,805
Construction in progress		98,844	34,358
Total		1,644,840	1,270,062
Less accumulated depreciation		338,050	294,740
Property, plant and equipment, net		$1,306,790	$ 975,322

Depreciation expense for the years ended December 31, 2001, 2000 and 1999 was $43.4 million, $33.3 million and $22.4 million, respectively. The increase in depreciation expense is primarily due to acquisitions and expansion capital projects over the last three years.

4. 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 operating segments, see Note 15.

The following table shows investments in and advances to unconsolidated affiliates at:

	December 31, 2001	December 31, 2000
Accounted for on equity basis:		
Fractionation:		
BRF	$ 29,417	$ 30,599
BRPC	18,841	25,925
Promix	45,071	48,670
Pipeline:		
EPIK	14,280	15,998
Wilprise	8,834	9,156
Tri-States	26,734	27,138
Belle Rose	11,624	11,653
Dixie	37,558	38,138
Starfish	25,352	
Neptune	76,880	
Nemo	12,189	
Evangeline	2,578	
Octane Enhancement:		
BEF	55,843	58,677
Accounted for on cost basis:		
Processing:		
VESCO	33,000	33,000
Total	$398,201	$298,954

The following table shows equity in income (loss) of unconsolidated affiliates for the year ended December 31:

	For Year Ended December 31,		
	2001	2000	1999
Fractionation:			
BRF	$ 1,583	$ 1,369	$ (336)
BRPC	1,161	(284)	16
Promix	4,201	5,306	630
Other			1,256
Pipeline:			
EPIK	345	3,273	1,173
Wilprise	472	497	160
Tri-States	1,565	2,499	1,035
Belle Rose	103	301	(29)
Dixie	2,092	751	
Starfish	4,122		
Ocean Breeze	32		
Neptune	4,081		
Nemo	75		
Evangeline	(145)		
Other			1,389
Octane Enhancement:			
BEF	5,671	10,407	8,183
Total	$ 25,358	$ 24,119	$ 13,477

At December 31, 2001, our share of accumulated earnings of equity method unconsolidated affiliates that had not been remitted to us was approximately $7.0 million.

Fractionation segment:

At December 31, 2001, 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 fractionation facility located in southeastern Louisiana.
- Baton Rouge Propylene Concentrator, LLC ("BRPC") - a 30.0% interest in a propylene concentration unit located in southeastern Louisiana.
- K/D/S Promix LLC ("Promix") - a 33.33% interest in an NGL fractionation facility and related storage assets located in south Louisiana. Our investment includes excess cost over the underlying equity in the net assets of Promix of $8.0 million. The excess cost, which relates to plant assets, is being amortized against our share of Promix's earnings over a period of 20 years, which is the estimated useful life of the plant assets that gave rise to the difference. The unamortized balance of excess cost was $7.0 million at December 31, 2001.

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 used in the following tables, gross operating margin for equity investments represents operating income before depreciation and amortization expense (both on operating assets) and selling, general and administrative costs.

	As Of or For The Year Ended December 31,		
	2001	2000	1999
BALANCE SHEET DATA:			
Current Assets	$ 27,424	$ 31,168	
Property, plant and equipment, net	251,519	264,618	
Other assets		67	
Total assets	$278,943	$295,853	
Current liabilities	$ 9,950	$ 13,661	
Combined equity	268,993	282,192	
Total liabilities and combined equity	$278,943	$295,853	
INCOME STATEMENT DATA:			
Revenues	$ 76,480	$ 71,287	$36,293
Gross operating margin	36,321	33,240	14,970
Operating income	22,396	19,997	5,930
Net income	22,738	20,661	4,200

Pipelines segment:

At December 31, 2001, 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 a refrigerated NGL marine terminal loading facility located in southeast Texas. The Company owns 50% of EPIK Terminalling L.P. which owns 99% of such facilities. We own 50% of EPIK Gas Liquids, LLC which owns 1% of such facilities. We do not exercise control over these entities; therefore, we are precluded from consolidating such entities into 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. Our investment includes excess cost over the underlying equity in the net assets of Dixie of $37.4 million. The excess cost, which relates to pipeline assets, is being amortized against our share of Dixie's earnings over a period of 35 years, which is the estimated useful life of the pipeline assets that gave rise to the difference. The unamortized balance of excess cost over the underlying equity in the net assets of Dixie was $35.7 million at December 31, 2001.
- 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.
- 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. We acquired our interest in Evangeline as a result of the Acadian Gas acquisition (see Note 2 for a description of this acquisition).

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,		
	2001	2000	1999
BALANCE SHEET DATA:			
Current Assets	$ 68,325	$ 25,464	
Property, plant and equipment, net	515,327	188,724	
Other assets	50,265	3,666	
Total assets	$633,917	$217,854	
Current liabilities	$ 62,347	$ 31,085	
Other liabilities	57,965	4,018	
Combined equity	513,605	182,751	
Total liabilities and combined equity	$633,917	$217,854	
INCOME STATEMENT DATA:			
Revenues	$305,404	$ 96,270	$52,386
Gross operating margin	98,682	51,414	24,845
Operating income	54,459	41,757	19,988
Net income	41,015	31,241	15,637

Equity investments in Gulf of Mexico natural gas pipeline systems in January 2001

On January 29, 2001, we acquired a 50% equity interest in Starfish which owns the Stingray natural gas pipeline system and a related natural gas dehydration facility. The Stingray system is a 379-mile, FERC-regulated natural gas pipeline system that transports natural gas and condensate from certain production areas located in the Gulf of Mexico offshore Louisiana to onshore transmission systems located in south Louisiana. The natural gas dehydration facility is connected to the onshore terminal of the Stingray system in south Louisiana. The optimal design capacity of the Stingray pipeline is 1.2 Bcf/d. Shell is the operator of these systems and owns the remaining equity interests in Starfish.

In addition to Starfish, we acquired a 25.67% interest in Ocean Breeze Pipeline Company ("Ocean Breeze") and Neptune and a 33.92% interest in Nemo. Ocean Breeze and Neptune collectively owned the Manta Ray and Nautilus natural gas pipeline systems located in the Gulf of Mexico offshore Louisiana. The Manta Ray system comprises approximately 235 miles of unregulated pipelines and related equipment with an optimal design capacity of 0.75 Bcf/d and the Nautilus system comprises approximately 101 miles of FERC-regulated pipelines with an optimal design capacity of 0.6 Bcf/d. The Nemo system, which became operational in August 2001, comprises 24-mile natural gas pipeline with an optimal design capacity of 0.3 Bcf/d. Like Stingray, Shell is the operator of the Manta Ray and Nemo systems. Shell is the administrative agent for Nautilus.. In November 2001, Ocean Breeze was merged into Neptune with the Company retaining its 25.67% interest in Neptune. Shell and Marathon are the co-owners of Neptune and Shell owns the remaining interest in Nemo.

The cash purchase price of the Starfish interest was $25 million with the purchase price of the Ocean Breeze, Neptune and Nemo interests being $87 million. The investments were paid for using proceeds from the issuance of the $450 million Senior Notes B (see Note 6).

Our investment in Neptune and Nemo includes excess cost over the underlying equity in the net assets of these entities of $13.5 million. The excess cost, which relates to pipeline assets, is being amortized against our share of earnings from Neptune and Nemo over a period of 35 years, which is the estimated useful life of the pipeline assets that gave rise to the difference. The unamortized balance of excess cost over the underlying equity in the net assets of Neptune and Nemo was $12.4 million and $0.7 million, respectively, at December 31, 2001.

Historical information for periods prior to January 1, 2001 do not reflect any impact associated with our equity investments in Starfish, Neptune and Nemo.

Octane Enhancement segment:

At December 31, 2001, 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 reduce the demand for MTBE and could have an adverse effect on our results of operations.

In recent years, MTBE has been detected in water supplies. The major source of the 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.

In light of these regulatory developments, the owners of BEF have been formulating a contingency plan for use of the BEF facility if MTBE were banned or significantly curtailed. Management is exploring a possible conversion of the BEF facility from MTBE production to alkylate production. The Company believes that if MTBE usage is banned or significantly curtailed, the motor gasoline industry would need a substitute additive to maintain octane levels in motor gasoline and that alkylate would be an attractive substitute. Depending upon the type of alkylate process chosen and the level of alkylate production desired, the cost to convert the facility from MTBE production to alkylate production would range from $20 million to $90 million, with our share of these costs ranging from $6.7 million to $30 million.

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,		
	2001	2000	1999
BALANCE SHEET DATA:			
Current Assets	$ 29,301	$ 20,640	
Property, plant and equipment, net	140,009	150,603	
Other assets	10,067	11,439	
Total assets	$179,377	$182,682	
Current liabilities	$ 13,352	$ 8,042	
Other liabilities	3,438	5,779	
Combined equity	162,587	168,861	
Total liabilities and combined equity	$179,377	$182,682	
INCOME STATEMENT DATA:			
Revenues	$213,734	$258,180	$193,219
Gross operating margin	28,701	43,328	43,479
Operating income	15,984	30,529	30,025
Income before accounting change	17,014	31,220	29,029
Net income	17,014	31,220	24,550

Processing segment:

At December 31, 2001, 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 Louisiana. We account for this investment using the cost method.

5. RECENTLY ISSUED ACCOUNTING STANDARDS

In June 2001, the FASB issued two new pronouncements: SFAS No. 141, "Business Combinations", and SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 141 prohibits the use of the pooling-of-interest method for business combinations initiated after June 30, 2001 and also applies to all business combinations accounted for by the purchase method that are completed after June 30, 2001. There are also transition provisions that apply to business combinations completed before July 1, 2001, that were accounted for by the purchase method. SFAS No. 142 is effective for our fiscal year that began January 1, 2002 for all goodwill and other intangible assets recognized in our consolidated balance sheet at that date, regardless of when those assets were initially recognized. We adopted SFAS No. 141 on January 1, 2002.

Within six months of our adoption of SFAS No. 142 (by June 30, 2002), we will have completed a transitional impairment review to identify if there is an impairment to the December 31, 2001 recorded goodwill or intangible assets of indefinite life using a fair value methodology. Professionals in the business valuation industry will be consulted to validate the assumptions used in such methodologies. Any impairment loss resulting from the transitional impairment test will be recorded as a cumulative effect of a change in accounting principle for the quarter ended June 30, 2002. Subsequent impairment losses will be reflected in operating income in the Statements of Consolidated Operations.

At January 1, 2002, our intangible assets included the values assigned to the 20-year Shell natural gas processing agreement (the "Shell agreement") and the excess cost of the purchase price over the fair market value of the assets acquired from Mont Belvieu Associates (the "MBA excess cost"), both of which were initially recorded in 1999. The value of the Shell agreement ($194.4 million net book value at December 31, 2001) is being amortized on a straight-line basis over its contract term. Likewise, the MBA excess cost ($7.9 million net book value at December 31, 2001) was being amortized on a straight-line basis over 20 years. Based upon initial interpretations of the new accounting standards, we anticipate that the intangible asset related to the Shell agreement will continue to be amortized over its contract term ($11.1 million annually for 2002 through July 2019); however, the MBA excess cost will be reclassified to goodwill in accordance with the new standard and its amortization will cease (currently, $0.5 million annually). This goodwill would then be subject to impairment testing as prescribed in SFAS No. 142. We are continuing to evaluate the complex provisions of SFAS No. 142 and will fully adopt the standard during 2002 within the prescribed time periods.

In addition to SFAS No. 141 and No. 142, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations", in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for our fiscal year beginning January 1, 2003. We are continuing to evaluate the provisions of this statement. In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment and/or disposal of long-lived assets. We adopted this statement effective January 1, 2002 and determined that it will have no material impact on our financial statements as of that date.

6. LONG-TERM DEBT

Our long-term debt consisted of the following at:

	December 31, 2001	December 31, 2000
Borrowings under:		
Senior Notes A, 8.25% fixed rate, due March 2005	$ 350,000	$ 350,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	
Total principal amount	854,000	404,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	1,653	
Less unamortized discount on:		
Senior Notes A	(117)	(153)
Senior Notes B	(258)	
Less current maturities of long-term debt	--	
Long-term debt	$ 855,278	$ 403,847

Long-term debt does not reflect the $250 million Multi-Year Credit Facility or the $150 million 364-Day Credit Facility. No amount was outstanding under either of these two revolving credit facilities at December 31, 2001. See below for a complete description of these facilities.

At December 31, 2001, we had a total of $75 million of standby letters of credit capacity under our $250 Million Multi-Year Credit Facility of which $2.4 million was outstanding.

Enterprise Products Partners L.P. acts as guarantor of certain debt obligations of its major subsidiary, the Operating Partnership. This parent-subsidiary guaranty provision exists under the Company's Senior Notes, MBFC Loan and its two current revolving credit facilities. In the descriptions that follow, the term "MLP" denotes Enterprise Products Partners L.P. in this guarantor role.

Senior Notes A. On March 13, 2000, we completed a public offering of $350 million in principal amount of 8.25% fixed-rate Senior Notes due March 15, 2005 at a price to the public of 99.948% per Senior Note (the "Senior Notes A"). These notes were issued to retire certain revolving credit loan balances that were created as a result of the TNGL acquisition and other general partnership activities.

The Senior Notes A are subject to a make-whole redemption right. The notes are an unsecured obligation and rank equally with existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness. The notes are guaranteed by the MLP through an unsecured and unsubordinated guarantee and were issued under an indenture containing certain restrictive covenants. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We were in compliance with these restrictive covenants at December 31, 2001.

Senior Notes B. On January 24, 2001, we completed a public offering of $450 million in principal amount of 7.50% fixed-rate Senior Notes due February 1, 2011 at a price to the public of 99.937% per Senior Note (the "Senior Notes B"). These notes were issued to finance the acquisition of Acadian Gas, Ocean Breeze, Neptune, Nemo and Starfish; to cover construction costs of certain NGL pipelines and related projects; and to fund other general partnership activities.

The Senior Notes B were issued under the same indenture as Senior Notes A and therefore are subject to similar terms and restrictive covenants. The Senior Notes B are guaranteed by the MLP through an unsecured and unsubordinated guarantee. We were in compliance with the restrictive covenants at December 31, 2001.

MBFC Loan. On March 27, 2000, we executed a $54 million loan agreement with the Mississippi Business Finance Corporation ("MBFC") having a 8.70% fixed-rate and a maturity date of March 1, 2010. In general, the proceeds from this loan were used to retire certain revolving credit loan balances attributable to acquiring and constructing the Pascagoula, Mississippi natural gas processing facility.

The MBFC Loan is subject to a make-whole redemption right and is guaranteed by the MLP through an unsecured and unsubordinated guarantee. The indenture agreement contains an acceleration clause whereby the outstanding principal and interest on the loan may become due and payable 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 in the indenture agreement) may, and if requested to do so by holders of at least 25% in aggregate of the principal amount of the outstanding underlying bonds, shall accelerate the maturity of the MBFC Loan, whereby the principal and all accrued interest would become immediately due and payable. If such an event occurred, we would have the option (a) to redeem the MBFC loan or (b) to provide an alternate credit agreement (as defined in the indenture agreement) to support our obligation under the MBFC loan, with both options exercisable within 120 days of receiving notice of the decline in our credit ratings from the ratings agencies.

The loan agreement contains certain covenants including maintaining appropriate levels of insurance on the Pascagoula facility and restrictions regarding mergers. We were in compliance with the restrictive covenants at December 31, 2001.

Multi-Year Credit Facility. On November 17, 2000, we entered into a $250 million five-year revolving credit facility that includes a sublimit of $75 million for letters of credit. The November 17, 2005 maturity date may be extended for one year at our option with the consent of the lenders, subject to the extension provisions in the agreement. We can increase the amount borrowed under this facility, with the consent of the Administrative Agent (whose consent may not be unreasonably withheld), up to an amount not exceeding $350 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders, so long as the aggregate amount of the funds borrowed under this credit facility and the 364-Day Credit Facility (described below) does not exceed $500 million. No lender will be required to increase its original commitment, unless it agrees to do so at its sole discretion. This credit facility is guaranteed by the MLP through an unsecured guarantee.

Proceeds from this credit facility will be used for working capital, acquisitions and other general partnership purposes. No amount was outstanding for this credit facility at December 31, 2001.

Our obligations under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. As defined within the agreement, borrowings under this bank credit facility will generally bear interest at either (i) the greater of the Prime Rate or the Federal Funds Effective Rate plus one-half percent or (ii) a Eurodollar Rate plus an applicable margin or (iii) a Competitive Bid Rate. We elect the basis for the interest rate at the time of each borrowing.

The credit agreement contains various affirmative and negative covenants applicable to the Company to, among other things, (i) incur certain indebtedness, (ii) grant certain liens, (iii) enter into certain merger or consolidation transactions and (iv) make certain investments. In addition, we may not directly or indirectly make any distribution in respect of its partnership interests, except those payments in connection with the Buy-Back Program (not to exceed $30 million in the aggregate, see Note 7) and distributions from Available Cash from Operating Surplus, both as defined within the agreement.

The credit agreement also requires that we satisfy certain financial covenants at the end of each fiscal quarter. As defined within the agreement, we (i) must maintain Consolidated Net Worth of $750 million and (ii) not permit our ratio of Consolidated Indebtedness to Consolidated EBITDA, including pro forma adjustments (as defined within the agreement), for the previous four quarter period to exceed 4.0 to 1.0. We were in compliance with the restrictive covenants at December 31, 2001.

364-Day Credit Facility. In conjunction with the Multi-Year Credit Agreement, we entered into a 364-day $150 million revolving bank credit facility. In November 2001, we and our lenders amended the revolving credit agreement to extend the maturity date to November 15, 2002 with the option to convert any revolving credit balance outstanding at November 15, 2002 to a one-year term loan.

We can increase the amount borrowed under this facility, with the consent of the Administrative Agent (whose consent may not be unreasonably withheld), up to an amount not exceeding $250 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders, so long as the aggregate amount of the funds borrowed under this credit facility and the Multi-Year Credit Facility do not exceed $500 million. No lender will be required to increase its original commitment, unless it agrees to do so at its sole discretion. This credit facility is guaranteed by the MLP through an unsecured guarantee.

Proceeds from this credit facility will be used for working capital, acquisitions and other general partnership purposes. No amount was outstanding for this credit facility at December 31, 2001.

Our obligations under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. As defined within the agreement, borrowings under this bank credit facility will generally bear interest at either (i) the greater of the Prime Rate or the Federal Funds Effective Rate plus one-half percent or (ii) a Eurodollar Rate plus an applicable margin or (iii) a Competitive Bid Rate. We elect the basis for the interest rate at the time of each borrowing.

Limitations on certain actions by the Company and financial condition covenants of this bank credit facility are substantially consistent with those existing for the Multi-Year Credit Facility as described previously. We were in compliance with the restrictive covenants at December 31, 2001.

February 2001 Registration Statement

On February 23, 2001, we filed a $500 million universal shelf registration (the "February 2001 Shelf") covering the issuance of an unspecified amount of equity or debt securities or a combination thereof. We expect to use the net proceeds from any sale of securities for future business acquisitions and other general corporate purposes, such as working capital, investments in subsidiaries, the retirement of existing debt and/or the repurchase of Common Units or other securities. The exact amounts to be used and when the net proceeds will be applied to partnership purposes will depend on a number of factors, including our funding requirements and the availability of alternative funding sources. We routinely review acquisition opportunities.

Increase in fair value of fixed-rate debt

Upon adoption of SFAS No. 133 (see Note 13), we recorded a $2.3 million fair value adjustment associated with our fixed-rate debt. The fair value adjustment is not a cash obligation of the Company and does not alter the amount of our indebtedness. Under the specific rules of SFAS 133, the fair value adjustment will be amortized over the remaining life of the fixed-rate debt to which it is associated, which approximates 10 years. See "Interest Rate Swaps" under Note 13 for additional information concerning this item.

Impact of interest rate swap agreements upon interest expense

During 2001 and 2000, we utilized interest rate swap agreements to manage debt service costs by converting a portion of our fixed-rate debt into variable-rate debt. Income or losses sustained on these financial instruments are reflected as a component of consolidated interest expense. At December 31, 2000, we had three interest rate swaps outstanding having a combined notional value of $154 million (attributable to fixed-rate debt) with an estimated fair value of $2.0 million. Due to the early termination of two of the swaps, the notional amount and fair value of the remaining swap was $54 million and $2.3 million (an asset), respectively, at December 31, 2001.

We recorded as a reduction of interest expense $13.2 million from our interest rates swaps during 2001 and $10.0 million during 2000. The income recognized in 2001 from these swaps includes the $2.3 million in non-cash mark-to-market income at December 31, 2001 (attributable to the sole remaining swap). The remaining $10.9 million has been realized. No mark-to-market income was recorded prior to the implementation of SFAS No. 133. For additional information regarding our interest rate swaps, see Note 13.

7. CAPITAL STRUCTURE

The Second Amended and Restated Agreement of Limited Partnership of the Company (the "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. When quarterly distributions exceed $0.506 per Unit, the General Partner receives a percentage of the excess between the actual distribution rate and the target level ranging from approximately 15% to 50% depending on the target level achieved.

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 (except for Common Units upon conversion of Subordinated Units, pursuant to employee benefit plans, upon conversion of the general partner interest as a result of the withdrawal of the General Partner or in connection with acquisitions or capital improvements that are accretive on a per Unit basis) or an equivalent number of securities ranking on a parity with the Common Units, without the approval of the holders of at least a Unit Majority. 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). After adjusting for the Units issued in connection with the TNGL acquisition, the number of Common Units available (and unreserved) to us for general partnership purposes during the Subordination Period was 27,275,000 at December 31, 2001.

Subordinated Units. The 21,409,870 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 the Subordinated Units may undergo an early conversion into Common Units should certain criteria be satisfied. Based upon these criteria, the earliest that the first 25% of the Subordinated Units would convert into Common Units is May 1, 2002. Should the criteria continue to be satisfied through the first quarter of 2003, an additional 25% of the Subordinated Units would undergo an early conversion into Common Units on May 1, 2003. The remaining 50% of Subordinated Units would convert on August 1, 2003 should the balance of the conversion requirements be 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 generally 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 14.5 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 6.0 million Special Units to Shell - 3.0 million were issued in August 2000 and 3.0 million in August 2001 under a contingent unit agreement. Of the cumulative 20.5 million Special Units issued, 6.0 million have already converted to Common Units (1.0 million in August 2000 and 5.0 million in August 2001). The remaining Special Units will convert to

Common Units on a one for one basis as follows: 9.5 million in August 2002 and 5.0 million in August 2003. These conversions have a dilutive effect on basic earnings per Unit.

Under the rules of the New York Stock Exchange, the conversion of Special Units into Common Units requires the approval of a majority of Common Unitholders. An affiliate of EPCO, which owns in excess of 62% of the outstanding Common Units, has voted its Units in favor of past conversions, which provided the necessary votes for approval.

Buy-Back Program. In 2000, the General Partner authorized us to repurchase and retire up to 1,000,000 of our publicly-held Common Units. The repurchase and retirements will be made during periods of temporary market weakness at price levels that would be accretive to our remaining Unitholders.

In September 2001, the General Partner approved a modification to the Buy-Back Program that allows both the Company (specifically, Enterprise Products Partners L.P.) and its consolidated revocable grantor trust (EPOLP 1999 Grantor Trust or the "Trust") to repurchase Common Units under the program. Under the terms of the modification, purchases made by the Company will continue to be retired whereas purchases made by the Trust will remain outstanding and not be retired. The Common Units purchased by the Trust will be accounted for as Treasury Units.

During 2000, the Company repurchased and retired 28,400 Common Units under this program. The Trust purchased 396,400 Common Units under this program in 2001. At December 31, 2001, 575,200 Common Units could be repurchased and/or retired under this program on a pre-split basis (see Note 16 for a discussion of a subsequent event involving the declaration of a two-for-one split of Common Units that will occur in May 2002).

Treasury Units acquired by Trust. During the first quarter of 1999, the Operating Partnership established the 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 Common Units purchased by the Trust are accounted for in a manner similar to treasury stock under the cost method of accounting. The Trust purchased 267,200 Common Units in 1999 at a cost of $4.7 million and 396,400 Common Units in 2001 at a cost of $18.0 million.

In November 2001, the Trust sold 500,000 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 has been credited to Partners' Equity accounts in a manner similar to additional paid-in capital.

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, 1997	33,552,915	21,409,870		
Units issued to public	12,000,000			
Balance, December 31, 1998	45,552,915	21,409,870		
Special Units issued to Shell in connection with TNGL acquisition			14,500,000	
Treasury Units purchased by consolidated Trust	(267,200)			267,200
Balance, December 31, 1999	45,285,715	21,409,870	14,500,000	267,200
Additional Special Units issued to Coral Energy, LLC in connection with contingency agreement			3,000,000	
Conversion of 1.0 million Coral Energy, LLC Special Units into Common Units	1,000,000		(1,000,000)	
Units repurchased and retired in connection with buy-back program	(28,400)			
Balance, December 31, 2000	46,257,315	21,409,870	16,500,000	267,200
Additional Special Units issued to Coral Energy, LLC in connection with contingency agreement			3,000,000	
Conversion of 5.0 million Coral Energy, LLC Special Units into Common Units	5,000,000		(5,000,000)	
Treasury Units purchased by consolidated Trust	(396,400)			396,400
Treasury Units reissued by consolidated Trust	500,000			(500,000)
Balance, December 31, 2001	51,360,915	21,409,870	14,500,000	163,600

8. 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. 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. The following table reconciles the number of Units used in the calculation of basic earnings per Unit and diluted earnings per Unit for each of the three years ended December 31, 2001, 2000 and 1999.

The weighted-average number of Common Units outstanding in 2001 and 2000 reflect the conversion of a portion of Shell's Special Units to Common Units in August of each year. Specifically, five million Special Units converted to Common Units in August 2001 and one million Special Units converted in August 2000. The weighted-average number of Special Units outstanding in 2001 and 2000 reflect the above conversions and the issuance of three million Special Units in August 2001 and August 2000. See Note 7 for additional information regarding Shell's Special Units.

	For Year Ended December 31,		
	2001	2000	1999
Income before minority interest	$ 244,650	$ 222,759	$ 121,521
General partner interest	(5,608)	(2,597)	(1,203)
Income before minority interest available to Limited Partners	239,042	220,162	120,318
Minority interest	(2,472)	(2,253)	(1,226)
Net income available to Limited Partners	$ 236,570	$ 217,909	$ 119,092
BASIC EARNINGS PER UNIT			
Numerator			
Income before minority interest available to Limited Partners	$ 239,042	$ 220,162	$ 120,318
Net income available to Limited Partners	$ 236,570	$ 217,909	$ 119,092
Denominator (weighted-average)			
Common Units outstanding	48,316	45,698	45,300
Subordinated Units outstanding	21,410	21,410	21,410
Total	69,726	67,108	66,710
Basic Earnings per Unit			
Income before minority interest available to Limited Partners	$ 3.43	$ 3.28	$ 1.80
Net income available to Limited Partners	$ 3.39	$ 3.25	$ 1.79
DILUTED EARNINGS PER UNIT			
Numerator			
Income before minority interest available to Limited Partners	$ 239,042	$ 220,162	$ 120,318
Net income available to Limited Partners	$ 236,570	$ 217,909	$ 119,092
Denominator (weighted-average)			
Common Units outstanding	48,316	45,698	45,300
Subordinated Units outstanding	21,410	21,410	21,410
Special Units outstanding	15,667	15,336	6,078
Total	85,393	82,444	72,788
Diluted Earnings per Unit			
Income before minority interest available to Limited Partners	$ 2.80	$ 2.67	$ 1.65
Net income available to Limited Partners	$ 2.77	$ 2.64	$ 1.64

9. 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 $0.45 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 quarterly distributions is increased after certain specified target levels are met. We made incentive distributions to the General Partner of $3.2 million during 2001 and $0.4 million during 2000.

The following table is a summary of cash distributions to partnership interests since the first quarter of 1999.

Cash Distribution History

	Per Common Unit	Per Subordinated Unit	Record Date	Payment Date
1999				
1st Quarter	$ 0.4500	$ 0.0700	Apr. 30, 1999	May 12, 1999
2nd Quarter	$ 0.4500	$ 0.3700	Jul. 30, 1999	Aug. 11, 1999
3rd Quarter	$ 0.4500	$ 0.4500	Oct. 29, 1999	Nov. 10, 1999
4th Quarter	$ 0.5000	$ 0.5000	Jan. 31, 2000	Feb. 10, 2000
2000				
1st Quarter	$ 0.5000	$ 0.5000	Apr. 28, 2000	May 10, 2000
2nd Quarter	$ 0.5250	$ 0.5250	Jul. 31, 2000	Aug. 10, 2000
3rd Quarter	$ 0.5250	$ 0.5250	Oct. 31, 2000	Nov. 10, 2000
4th Quarter	$ 0.5500	$ 0.5500	Jan. 31, 2001	Feb. 9, 2001
2001				
1st Quarter	$ 0.5500	$ 0.5500	Apr. 30, 2001	May 10, 2001
2nd Quarter	$ 0.5875	$ 0.5875	Jul. 31, 2001	Aug. 10, 2001
3rd Quarter	$ 0.6250	$ 0.6250	Oct. 31, 2001	Nov. 9, 2001
4th Quarter	$ 0.6250	$ 0.6250	Jan. 31, 2002	Feb. 11, 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.

10. RELATED PARTY TRANSACTIONS

We have no employees. All management, administrative and operating functions are performed by employees of EPCO pursuant to the EPCO Agreement (in effect since July 1998). Under the terms of the EPCO Agreement, EPCO agreed to:

- employ the personnel necessary to manage our business and affairs (through the General Partner);
- employ the operating personnel involved our business for which we reimburse EPCO at cost (based upon EPCO's actual salary costs and related fringe benefits);
- 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 use all of the EPCO trademarks and trade names;
- indemnify us against any losses resulting from certain lawsuits; and to
- 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 its' purchase option under such leases to us. EPCO remains liable for the lease payments associated with these assets.

Operating costs and expenses (as shown in the audited Statements of Consolidated Operations) treat the full amount of lease payments being made by EPCO as a non-cash operating expense (with the offset to Partners' Equity on the Consolidated Balance Sheet). In addition, operating costs and expenses include compensation charges for EPCO's employees who operate the facilities.

Pursuant to the EPCO Agreement, we reimburse EPCO for our portion of the costs of certain of its employees who manage our business and affairs. In general, our reimbursement of EPCO's expense associated with administrative positions that were active at the time of our initial public offering in July 1998 is capped by the Administrative Services Fee that we pay (currently at $16 million annually). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to annual 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 (including those associated with equity-based awards granted to certain individuals within this group) and the Administrative Services Fee will be retained by EPCO (i.e., EPCO solely bears any shortfall in reimbursement for this group).

Beginning in January 2000, we began reimbursing EPCO for our share of the compensation of administrative personnel that it had hired in response to our expansion and business development activities (through the construction of new facilities, business acquisitions or the like). EPCO began hiring "expansion" administrative personnel during 1999 in connection with the TNGL acquisition and other development activities. In general, we reimburse EPCO for our share of its compensation expense associated with these "expansion" administrative positions, including those costs attributable to equity-based awards.

The following table summarizes the Administrative Services Fee paid to EPCO during the last three years. In addition, the table shows the total compensation reimbursed to EPCO for operations personnel and "expansion" administrative positions.

	For Year Ended December 31,		
	2001	2000	1999
Administrative Services Fee paid to EPCO	$ 15,125	$ 13,750	$ 12,500
Compensation reimbursed to EPCO	48,507	44,717	26,889
Total	$ 63,632	$ 58,467	$ 39,389

We elected to prepay EPCO a discounted amount of $15.7 million for the 2002 Administrative Services Fee in December 2001 (the undiscounted amount was $16.0 million). We will owe EPCO for any undiscounted amount above the $16.0 million if the General Partner approves an increase in the fee during 2002.

Other related party and similar transactions with EPCO or its affiliates

EPCO also operates the facilities owned by BEF and EPIK and charges them for actual salary costs and related fringe benefits. In addition, EPCO is paid a management fee by these entities in lieu of reimbursement for the actual cost of providing management services; such charges aggregated $0.8 for 2001, $0.9 million for 2000 and $0.8 million in 1999.

We have entered into an agreement with EPCO to provide trucking services related to the loading and transportation of NGL products. EPCO charged us $9.0 million in 2001, $7.9 million in 2000 and $5.7 million in 1999 for these services. On occasion, in the normal course of business, we may engage in transactions with EPCO involving the buying and selling of NGL products. No such sales or purchases were transacted with EPCO during 2001 and 2000; however, we purchased a net $20.6 million of such products from EPCO during 1999.

In addition, trust affiliates of EPCO (Enterprise Products 1998 Unit Option Plan Trust and the Enterprise Products 2000 Rabbi Trust) purchase Common Units for the purpose of granting options to EPCO management and certain key employees (many of whom also serve in similar capacities with the General Partner). During 2001, these trusts purchased 211,518 Common Units on the open market or through privately negotiated transactions. At December 31, 2001, these trusts owned a total of 1,461,518 Common Units. In November 2001, EPCO directly purchased

500,000 Common Units at market prices from our consolidated trust, EPOLP 1999 Grantor Trust, on behalf of a key executive.

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.

Relationships with Shell

We have an extensive and ongoing relationship with Shell as a partner, customer and vendor. Shell, through its subsidiary Shell US Gas & Power LLC, owns approximately 23.2% of our limited partnership interests and 30.0% of the General Partner. Currently, three members of the Board of Directors of the General Partner are employees of Shell.

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 the Gulf of Mexico within the state and federal waters off Texas, Louisiana, Mississippi, Alabama and Florida (on a keepwhole basis). This includes natural gas production from deepwater developments. Shell is the largest oil and gas producer and holds one of the largest lease positions in the deepwater Gulf of Mexico. Generally, this contract has the following rights and obligations:

- the exclusive right to process any and all of Shell's Gulf of Mexico natural gas production from existing and future dedicated 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 deliver to Shell the natural gas stream after the mixed NGL stream is extracted.

Apart from operating expenses arising from the Shell Processing Agreement, we also sell NGL and petrochemical products to Shell.

The following table shows the related party amounts by major category in the Company's Statements of Consolidated Operations for the last three years. The table also shows the total amounts paid to EPCO separately under the EPCO Agreement for employee-related costs for the last three years.

	For Year Ended December 31,		
	2001	2000	1999
Revenues from consolidated operations			
Unconsolidated affiliates	$ 173,684	$ 61,988	$ 40,352
Shell	333,333	292,741	56,301
EPCO and subsidiaries	5,439	4,750	9,148
Operating costs and expenses			
Unconsolidated affiliates	41,062	58,202	20,696
Shell	705,440	736,655	188,570
EPCO and subsidiaries	10,075	9,492	35,046
EPCO Agreement	63,632	58,467	39,389

11. COMMITMENTS AND CONTINGENCIES

Redelivery Commitments

From time to time, we store NGL, petrochemical and natural gas volumes for third parties under various processing, storage and similar agreements. Under the terms of these agreements, we are generally required to redeliver to the owner volumes on demand. We are insured for any physical loss of such volumes due to catastrophic events. At

December 31, 2001, NGL and petrochemical volumes aggregating 320 million gallons were due to be redelivered to their owners along with 887,414 MMBtus 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, 2001 are as follows:

2002	$ 5,115
2003	4,862
2004	4,324
2005	279
2006	181
Thereafter	1,077
Total minimum obligations	$ 15,838

The operating lease commitments shown above exclude the expense associated with various equipment leases contributed to us by EPCO at our formation for which EPCO has retained the liability. During 2001, 2000 and 1999, our non-cash lease expense associated with these EPCO "retained" leases was $10.4 million, $10.6 million and $10.6 million, respectively.

Lease and rental expense (including Retained Leases) included in operating income for the years ended December 31, 2001, 2000 and 1999 was approximately $23.4 million, $21.2 million and $20.6 million. EPCO has assigned us the purchase options associated with the retained leases. Should we decide to exercise our purchase options under the retained leases, up to $26.0 million will be payable in 2004, $3.4 million in 2008 and $3.1 million in 2016.

Purchase Commitments

Gas purchase commitments. We have long-term purchase commitments for NGL products and related-streams including natural gas with several suppliers. The purchase prices contained within these contracts approximate market value at the time of delivery. The following table shows our long-term volume commitments under these contracts.

	2002	2003	2004	2005	2006	Thereafter
NGLs (000s barrels):						
Ethane	2,154	2,154	1,677	1,089	126	
Propane	2,898	2,826	1,899	900	102	
Isobutane	498	498	387	252	30	
Normal Butane	1,134	964	735	303	34	
Natural Gasoline	1,944	1,944	1,488	846	48	
Other	960	460	180			
Total NGLs	9,588	8,846	6,366	3,390	340	
Natural gas (BBtus)	13,726	13,726	12,996	12,996	12,996	75,600

Capital spending commitments. As of December 31, 2001, we had capital expenditure commitments totaling approximately $5.3 million, of which $0.3 million relates to our portion of internal growth projects of unconsolidated affiliates.

Litigation

We are indemnified for any litigation pending as of the date of our formation by EPCO. 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. Except as noted below, 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.

Our operations are subject to the Clean Air Act and comparable state statutes. Amendments to the Clean Air Act were adopted in 1990 and contain provisions that may result in the imposition of certain pollution control requirements with respect to air emissions from our pipelines and processing and storage facilities. For example, the Mont Belvieu processing and storage facilities are located in the Houston-Galveston ozone non-attainment area, which is categorized as a "severe" area and, therefore, is subject to more restrictive regulations for the issuance of air permits for new or modified facilities. The Houston-Galveston area is among nine areas of the country in this "severe" category. One of the other consequences of this non-attainment status is the potential imposition of lower limits on emissions of certain pollutants, particularly oxides of nitrogen which are produced through combustion, as in the gas turbines at the Mont Belvieu complex.

Regulations imposing more strict air emissions requirements on existing facilities in the Houston-Galveston area were issued in December 2000. These regulations may necessitate extensive redesign and modification of our Mont Belvieu facilities to achieve the air emissions reductions needed for federal Clean Air Act compliance. The technical practicality and economic reasonableness of these regulations have been challenged under state law in litigation filed on January 19, 2001, against the Texas Natural Resource Conservation Commission and its principal officials in the District Court of Travis County, Texas, by a coalition of major Houston-Galveston area industries, including us. Until this litigation is resolved, the precise level of technology to be employed and the cost for modifying the facilities to achieve the required amount of reductions cannot be determined. Currently, the litigation has been stayed by agreement of the parties pending the outcome of expanded, cooperative scientific research to more precisely define sources and mechanisms of air pollution in the Houston-Galveston area. Completion of this research is anticipated in mid-2002.

12. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

	For Year Ended December 31,		
	2001	2000	1999
(Increase) decrease in:			
Accounts receivable	$ 230,629	$(93,716)	$(152,363)
Inventories	30,862	(21,452)	7,471
Prepaid and other current assets	(25,524)	2,352	(7,523)
Intangible assets		(5,226)	
Other assets	162	(1,410)	1,164
Increase (decrease) in:			
Accounts payable	(82,075)	18,723	(6,276)
Accrued gas payable	(197,916)	143,457	206,178
Accrued expenses	(1,576)	4,978	(27,788)
Accrued interest	14,234	8,743	863
Other current liabilities	3,073	6,540	5,884
Other liabilities	(9,012)	8,122	296
Net effect of changes in operating accounts	$ (37,143)	$ 71,111	$ 27,906
Cash payments for interest, net of $2,946, $3,277 and $153 capitalized in 2001, 2000 and 1999, respectively	$ 37,536	$ 17,774	$ 15,780

On April 1, 2001, we paid approximately $225.7 million in cash to Shell to acquire Acadian Gas. This acquisition was recorded using the purchase method of accounting and as a result the initial purchase price has been allocated to various balance sheet asset and liability accounts. For additional information regarding the acquisition of Acadian Gas (including the allocation of the purchase price), see Note 2.

On August 1, 1999, we paid $166 million in cash and issued 14.5 million non-distribution bearing, convertible Special Units (valued at $210.4 million at time of issuance) to Shell in connection with the TNGL acquisition. Also, we issued 6.0 million additional non-distribution bearing, convertible Special Units to Shell based on Shell having met certain performance criteria in calendar years 2000 and 2001. Of the 6.0 million additional Special Units issued, 3.0 million were issued in 2000 and 3.0 million during 2001. The value of the Special Units issued in 2000 was $55.2 million while the value of those issued during 2001 was $117.1 million, both values determined using present value techniques. The $172.3 million combined value of these two issues increased the overall purchase price of the TNGL acquisition and was allocated to the intangible asset, Shell Processing Agreement. In addition, during 2000, we increased the value of the Shell Processing Agreement by $25.2 million for non-cash purchase accounting adjustments related to the acquisition. The offset to such adjustment was various working capital accounts. With these adjustments completed, the final purchase price of TNGL increased to $528.8 million.

On July 1, 1999, we paid approximately $42.1 million in cash to EPCO and Kinder Morgan and assumed approximately $4 million of debt in connection with the acquisition of an additional interest in the Mont Belvieu NGL fractionation facility.

As a result of our adoption of SFAS No. 133 on January 1, 2001, we record various financial instruments relating to commodity positions and interest rate swaps at their respective fair values using mark-to-market accounting. During 2001, we recognized a net $5.7 million in non-cash mark-to-market income related to increases in the fair value of these financial instruments. See Note 13 for additional information on our financial instruments.

13. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices in our natural gas and NGL businesses and in interest rates with respect to a portion of its debt obligations. 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 in its Processing segment. In general, the types of risks hedged 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.

Our disclosure of fair value estimates are determined using available market information and appropriate valuation methodologies. We must use considerable judgment, however, in interpreting market data and to develop the related estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize upon disposition of the financial instruments. The use of different market assumptions and/or estimation methodologies may have a material effect on our estimates of fair value.

Commodity financial instruments

Our Processing and Octane Enhancement segments are directly exposed to commodity price risk through their respective business operations. The prices of natural gas, NGLs 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 its Processing segment, we may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The primary purpose of these risk management activities is to hedge exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. We do not hedge our exposure to the MTBE markets. Also, in its Pipelines segment, we may utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges certain of its customers for natural gas.

We have adopted a commercial policy to manage our exposure to the risks of its 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 its commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 18 months. The General Partner oversees the 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.

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.

At December 31, 2001, we had open commodity financial instruments that settle at different dates extending through December 2002. We routinely review our outstanding 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 economic hedge to which the closed instrument relates.

These commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 because of ineffectiveness. A hedge is normally regarded as effective if, among other things, at inception and throughout the term of the financial instrument, we could expect changes in the fair value of the hedged item to be almost fully offset by the changes in the fair value of the financial instrument. Currently, a majority of our commodity financial instruments do not qualify as effective hedges under the guidelines of SFAS No. 133, with the result being that changes in the fair value of these positions are recorded on the balance sheet and in earnings through mark-to-market accounting. The use of mark-to-market accounting for these commodity financial instruments results in a degree of non-cash earnings volatility that is dependent upon changes in the underlying commodity prices. Even though these financial instruments do not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133, we continue to view these financial instruments as hedges inasmuch as this was the intent when such contracts were executed. This characterization is consistent with the actual economic performance of these contracts to date and we expect these financial instruments to continue to mitigate (or offset) commodity price risk in future. The specific accounting for these contracts, however, is consistent with the requirements of SFAS No. 133.

We recognized income of $101.3 million in 2001 from our commodity hedging activities that is treated as a decrease of operating costs and expenses in the Statements of Consolidated Operations. Of this amount, $95.7 million was realized during 2001. The remaining $5.6 million represents mark-to-market income on positions open at December 31, 2001 (based on market prices at that date).

Interest rate swaps

Our interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to its Senior Notes and MBFC Loan. We manage its exposure to changes in interest rates by utilizing interest rate swaps. The objective of holding 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. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount. We believe that it is prudent to maintain an appropriate mixture of variable-rate and fixed-rate debt.

We assess interest rate cash flow risk by identifying and measuring changes in interest rate exposure that impact future cash flows and evaluating hedging opportunities. We use analytical techniques to measure its 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 financial risks and approves instruments that are appropriate for our requirements. The notional amount of an interest rate swap 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 is remote, and that if incurred, such losses would be immaterial.

At December 31, 2001, we had one interest rate swap outstanding having a notional amount of $54 million extending through March 2010. Under this agreement, we exchanged a fixed-rate of 8.70% for a variable-rate that ranged from 4.28% to 7.66% during 2001 (the variable-rate may fluctuate over time depending on market conditions). If it elects to do so, the counterparty may terminate this swap in March 2003. During 2001, two counterparties terminated their swap agreements with us either through early termination clauses or negotiation. The closed agreements had a combined notional amount of $100 million.

Upon adoption of SFAS No. 133, we were required to recognize the fair value of the interest rate swaps on the balance sheet offset by an equal increase in the fair value of associated fixed-rate debt and, therefore, the adoption of the new standard had no impact on earnings at transition. Subsequently, it was determined that the interest rate swaps would not qualify for hedge accounting treatment under SFAS No. 133 due to differences between the maturity dates of the swaps and the associated fixed-rate debt; thus, changes in the fair value of the interest rate swaps would be recorded in earnings through mark-to-market accounting (i.e., the interest rate swaps were deemed ineffective under SFAS No. 133). As a result, the increase in fair value of the associated fixed-rate debt will not be adjusted for future changes in its fair value and will be amortized to earnings over the remaining life of the underlying debt instrument, which approximates 10 years.

We recognized income of $13.2 million in 2001 from our interest rate swaps that is treated as a reduction of interest expense in the Statements of Consolidated Operations. Of this amount, $2.3 million represents the mark-to-market income on the remaining swap at December 31, 2001 (estimated fair value of swap based on market rates at that date). The balance of $10.9 million was realized during 2001.

The $2.3 million estimated fair value of the remaining swap at December 31, 2001 is based on market rates (assuming its early termination option in March 2003 is exercised). The fair value estimate represents the amount that we would receive to terminate the swap, taking into consideration current interest rates.

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.

Other 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.

Fixed-rate long term debt. The estimated fair value of our fixed-rate long-term debt is estimated based on quoted market prices for debt of similar terms and maturities. No variable rate long-term debt was outstanding at December 31, 2001.

The following table summarizes the estimated fair values of our various financial instruments at December 31, 2001 and 2000:

Financial Instruments	2001 Carrying Amount	2001 Fair Value	2000 Carrying Amount	2000 Fair Value
Financial assets:				
Cash and cash equivalents	$ 137,823	$ 137,823	$ 60,409	$ 60,409
Accounts receivable (1)	261,302	261,302	415,618	415,618
Commodity financial instruments (2)	9,992	9,992	n/a	n/a
Interest rate swaps (3)	2,324	2,324	n/a	n/a
Financial liabilities:				
Accounts payable and accrued expenses	364,452	364,452	561,688	561,688
Fixed-rate debt (principal amount)	854,000	894,005	404,000	423,836
Commodity financial instruments (4)	3,206	3,206	725	705
Off-balance sheet instruments: (5)				
Interest rate swaps receivable	n/a	n/a	2,030	2,030
Commodity financial instruments payable	n/a	n/a	40,020	39,266

(1) 2001 includes a $1.2 million receivable related to the remaining interest rate swap

(2) 2001 values are a component of other current assets in our consolidated balance sheet

(3) 2001 value represents the aggregate fair value of the remaining swap (net of the $1.2 million receivable reflected under accounts receivable). $1.3 million of the $2.3 million mark-to-market value is a component of other current assets while the balance of $1.0 million is reflected in other assets.

(4) 2001 values are a component of other current liabilities in our consolidated balance sheet

(5) Prior to our adoption of SFAS No. 133 on January 1, 2001, interest rate swaps and certain commodity financial instruments were off-balance sheet instruments. As a result of SFAS No. 133, these financial instruments are now recorded as part of balance sheet assets and liabilities, as the circumstances warrant.

14. 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. Although this concentration could affect our overall exposure to credit risk since these customers might be affected by similar economic or other conditions, management believes we are exposed to minimal credit risk, since the majority of our business is conducted with major companies within the industry including those with whom it has joint operations. We do not require collateral for our accounts receivable.

Nature of Operations. We are subject to a number of risks inherent in the industry in which it operates, including fluctuating gas and liquids prices. Our financial condition and results of operation will depend significantly on the prices received for NGLs and the price paid for gas consumed in the NGL extraction process. These 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 its processing business in order to maintain or increase gas plant throughput 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 NGL 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.

Counterparty risk. From time to time, we have credit risk with our counterparties in terms of settlement risk associated with its financial instruments. 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 $10.6 million reserve for amounts owed to us by Enron North America, a subsidiary of Enron. Enron North America was our counterparty to various past financial instruments. The Enron amounts were unsecured and the amount that we may ultimately recover, if any, is not presently determinable. Of the reserve amount established, $4.3 million was attributable to various unbilled commodity financial instrument positions that terminate during the first quarter of 2002.

15. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available and that 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: Fractionation, Pipelines, 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. Fractionation primarily includes NGL fractionation, isomerization, and polymer grade propylene fractionation services. Pipelines consists of both liquids and natural gas pipeline systems, storage and import/export terminal services. Processing includes the natural gas processing business and its related merchant 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 other plant support functions.

We evaluate segment performance based on 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 interest expense, interest income (from unconsolidated affiliates or others), dividend income from unconsolidated affiliates, minority interest, extraordinary charges and other income and expense transactions.

We include equity earnings from unconsolidated affiliates in segment gross operating margin and as a component of revenues. 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 these businesses 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 merchant businesses. 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.

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.

Segment gross operating margin is inclusive of intersegment revenues, which are generally based on transactions made at market-related rates. These revenues have been eliminated from the consolidated totals.

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

	Operating Segments						
	Fractionation	Pipelines	Processing	Octane Enhancement	Other	Adjs. and Elims.	Consol. Totals
Revenues from external customers:							
2001	$324,276	$403,430	$2,424,281		$2,382		$3,154,369
2000	396,995	28,172	2,620,975		2,878		3,049,020
1999	247,579	11,498	1,073,171		731		1,332,979
Intersegment revenues:							
2001	158,853	89,907	683,524		389	$(932,673)	
2000	177,963	55,690	630,155		375	(864,183)	
1999	118,103	43,688	216,720		444	(378,955)	
Equity income in unconsolidated affiliates:							
2001	6,945	12,742		$ 5,671			25,358
2000	6,391	7,321		10,407			24,119
1999	1,566	3,728		8,183			13,477
Total revenues:							
2001	490,074	506,079	3,107,805	5,671	2,771	(932,673)	3,179,727
2000	581,349	91,183	3,251,130	10,407	3,253	(864,183)	3,073,139
1999	367,248	58,914	1,289,891	8,183	1,175	(378,955)	1,346,456
Gross operating margin by segment:							
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
1999	110,424	31,195	28,485	8,183	908		179,195
Segment assets:							
2001	357,122	717,348	124,555		8,921	98,844	1,306,790
2000	356,207	448,920	126,895		8,942	34,358	975,322
1999	362,198	249,453	122,495		113	32,810	767,069
Investments in and advances to unconsolidated affiliates:							
2001	93,329	216,029	33,000	55,843			398,201
2000	105,194	102,083	33,000	58,677			298,954
1999	99,110	85,492	33,000	63,004			280,606

Our revenues are derived from a wide customer base. Shell accounted for 10.5% of consolidated revenues in 2001 (up from 9.5% of consolidated revenues in 2000). No single external customer accounted for more than 10% of consolidated revenues during 2000 and 1999. Approximately 80% of our revenues from Shell during 2001 and 2000 are attributable to sales of NGL products which are recorded in our Processing segment. No single third-party customer provided more than 10% of consolidated revenues during 2000 or 1999. All consolidated revenues were earned in the United States. Our operations are centered along the Texas, Louisiana and Mississippi Gulf Coast areas.

A reconciliation of segment gross operating margin to consolidated income before minority interest follows:

	For Year Ended December 31,		
	2001	2000	1999
Total segment gross operating margin	$ 376,783	$ 320,615	$ 179,195
Depreciation and amortization	(48,775)	(35,621)	(23,664)
Retained lease expense, net	(10,414)	(10,645)	(10,557)
(Gain) loss on sale of assets	390	(2,270)	(123)
Selling, general and administrative	(30,296)	(28,345)	(12,500)
Consolidated operating income	287,688	243,734	132,351
Interest expense	(52,456)	(33,329)	(16,439)
Interest income from unconsolidated affiliates	31	1,787	1,667
Dividend income from unconsolidated affiliates	3,462	7,091	3,435
Interest income - other	7,029	3,748	886
Other, net	(1,104)	(272)	(379)
Consolidated income before minority interest	$ 244,650	$ 222,759	$ 121,521

16. SUBSEQUENT EVENTS (UNAUDITED)

Purchase of Diamond-Koch storage assets. On January 17, 2002, we completed the purchase of various hydrocarbon storage assets from affiliates of Valero Energy Corporation and Koch Industries, Inc. The purchase price of the storage assets was approximately $129 million (subject to certain post-closing adjustments) and will be accounted for as an asset purchase. The purchase price was funded entirely by internally generated funds.

The storage facilities include 30 salt dome storage caverns with a total useable capacity of 68 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.

Purchase of Diamond-Koch propylene fractionation assets. On February 1, 2002, we completed the purchase of various propylene fractionation assets from affiliates of Valero Energy Corporation and Koch Industries, Inc. and certain inventories of refinery grade propylene, propane and polymer grade propylene owned by such affiliates. The purchase price of these assets was approximately $238.5 million (subject to certain post-closing adjustments) and will be accounted for as an asset purchase. The purchase price was funded by a drawdown on our existing revolving bank credit facilities.

The propylene fractionation assets being acquired include a 66.67% interest in a polymer grade propylene fractionation facility located in Mont Belvieu, Texas, a 50.0% 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. The propylene fractionation facility has the gross capacity to produce approximately 41,000 barrels per day of polymer grade propylene.

Both the storage and propylene fractionation acquisitions have been approved by the requisite regulatory authorities. The post-closing purchase price adjustments of both transactions are expected to be completed during the second quarter of 2002.

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 will be accomplished by distributing one additional partnership Unit for each partnership Unit outstanding to holders of record on April 30, 2002. The Units will be distributed on May 15, 2002. All references to number of Units or earnings per Unit contained in this document relate to the pre-split Units, except if otherwise indicated.

17. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2000:				
Revenues	$ 753,724	$ 604,010	$ 721,863	$ 993,542
Operating income	75,434	50,046	55,864	62,390
Income before minority interest	70,156	46,026	50,777	55,800
Minority interest	(709)	(466)	(514)	(564)
Net income	69,447	45,560	50,263	55,236
Net income per Unit, basic	$ 1.03	$ 0.68	$ 0.74	$ 0.81
Net income per Unit, diluted	$ 0.85	$ 0.56	$ 0.60	$ 0.65
For the Year Ended December 31, 2001:				
Revenues	$ 838,326	$ 968,447	$ 729,618	$ 643,336
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	$ 0.76	$ 1.35	$ 1.04	$ 0.28
Net income per Unit, diluted	$ 0.61	$ 1.09	$ 0.85	$ 0.23

Earnings in the fourth quarter of 2001 declined relative to the third quarter of 2001 primarily due to a decrease in the mark-to-market value of our commodity financial instruments. The decrease was due to (1) the settlement of certain positions during the fourth quarter, (2) a decrease in the relative amount of hedging activities at December 31, 2001 versus September 30, 2001 and (3) a decrease in the value of certain outstanding financial instruments from September 30, 2001 due to changes in natural gas prices.

SCHEDULE II

Enterprise Products Partners L.P.
Valuation and Qualifying Accounts

	For Years Ended December 31, 2001	2000	1999
Accounts receivable - trade			
Allowance for doubtful accounts			
Balance at beginning of period	$ 10.9	$ 15.9	
Increase in allowance account attributable to Enron bankruptcy that was charged to earnings (1)	6.3		
Other allowance account amounts charged to earnings	(2.3)		$ 3.0
Changes in allowance account charged to other balance sheet accounts (2)	6.5		12.9
Amounts charged against allowance account	(0.8)	(5.0)	
Balance at end of period	$ 20.6	$ 10.9	$ 15.9
Other current assets			
Additional credit reserve for Enron (1)			
Balance at beginning of period			
Increase in credit reserve attributable to Enron bankruptcy that was charged to earnings	$ 4.3		
Amounts charged against credit reserve			
Balance at end of period	$ 4.3		
Other current liabilities			
Reserve for inventory gains and losses (3)			
Balance at beginning of period	$ 5.7	$ 2.9	$ 0.8
Reserve increases charged to earnings	0.5	0.5	2.8
Reserve reconciliation adjustment (4)	(2.4)		(0.8)
Inventory gains (losses) charged to reserve	(1.8)	2.3	0.1
Balance at end of period	$ 2.0	$ 5.7	$ 2.9

---

(1) In December 2001, Enron North America (our counterparty to various past financial instruments) filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As a result, we established a $10.6 million reserve for 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. Of the $10.6 million reserve we established, $6.3 million offsets invoices that had been billed to Enron as of December 31, 2001 with the remaining $4.3 million in a credit reserve offsetting various unbilled commodity financial instrument positions. The unbilled amounts are expected to be settled and invoiced during the first quarter of 2002.
(2) Prior to the TNGL acquisition in 1999, we did not experience any significant losses from bad debts and therefore did not require an allowance account. As a result of the TNGL acquisition in August 1999, we acquired a $12.9 million allowance for doubtful accounts. In April 2001, we acquired an additional $6.5 million allowance for doubtful accounts in connection with the acquisition of Acadian Gas.
(3) The reserve for inventory gains and losses generally denotes net underground NGL storage well product losses.
(4) A review of the reserve balance was performed during the fourth quarter of 2001 and based upon its findings and estimated future losses, a reserve balance of $2.0 million at December 31, 2001 was deemed appropriate..

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on March 21, 2002.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)
By: Enterprise Products GP, LLC
as General Partner

By: /s/ Michael J. Knesek
Name: Michael J. Knesek
Title: Vice President, Controller and Principal Accounting Officer of Enterprise Products GP, LLC

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 21, 2002:

Signature	Positions held in General Partner
/s/ Dan L. Duncan Dan L. Duncan	Chairman of the Board and Director
/s/ O.S. Andras O.S. Andras	President, Chief Executive Officer and Director
/s/ Randa Duncan Williams Randa Duncan Williams	Director
/s/ Richard H. Bachmann Richard H. Bachmann	Executive Vice President, Chief Legal Officer, Secretary and Director
/s/ Michael A. Creel Michael A. Creel	Chief Financial Officer and Executive Vice President
/s/ J.A. Berget J.A. Berget	Director
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director
/s/ J. R. Eagan J.R. Eagan	Director
/s/ Curtis R. Frasier Curtis R. Frasier	Director
/s/ Lee W. Marshall, Sr. Lee W. Marshall, Sr.	Director
/s/ Richard S. Snell Richard S. Snell	Director

Exhibit 4.13

FIRST AMENDMENT AND SUPPLEMENT TO CREDIT AGREEMENT

Dated November 6, 2001,
to be effective as of November 16, 2001

among

ENTERPRISE PRODUCTS OPERATING L.P.

The Lenders Party Hereto

FIRST UNION NATIONAL BANK,
as Administrative Agent

BANK ONE, N.A. and THE BANK OF NOVA SCOTIA,
as Co-Syndication Agents

FLEET NATIONAL BANK and
WESTDEUTSCHE LANDESBANK GIROZENTRALE, NEW YORK BRANCH,
as Co-Documentation Agents

FIRST UNION SECURITIES, INC.,
As Sole Arranger and Sole Book Manager

364-Day Revolving Credit Facility

FIRST AMENDMENT AND SUPPLEMENT

TO CREDIT AGREEMENT

THIS FIRST AMENDMENT AND SUPPLEMENT TO CREDIT AGREEMENT (this "First Amendment") is made and entered into this 6th day of November, 2001, to be effective as of the 16th day of November of 2001 (the "Effective Date"), among ENTERPRISE PRODUCTS OPERATING L.P., a Delaware limited partnership ("Borrower"); FIRST UNION NATIONAL BANK, as administrative agent (in such capacity, the "Administrative Agent") for each of the lenders (the "Lenders") that is a signatory or which becomes a signatory to the hereinafter defined Credit Agreement; and the Lenders.

R E C I T A L S:

A. On November 17, 2000, the Borrower, the Lenders and the Administrative Agent entered into a certain Credit Agreement (the "Credit Agreement") whereby, upon the terms and conditions therein stated, the Lenders agreed to make certain Loans (as such term is defined in the Credit Agreement) and extend certain credit to the Borrower.

B. Bank One, N.A. and The Bank of Nova Scotia have been appointed to act as Co-Syndication Agents under the Credit Agreement from and after the Effective Date of this First Amendment; and Fleet National Bank and Westdeutsche Landesbank Girozentrale, New York Branch have been appointed to act as Co-Documentation Agents under the Credit Agreement from and after the Effective Date of this First Amendment.

C. First Union Securities, Inc. shall be the Sole Arranger and Sole Book Manager under the Credit Agreement from and after the Effective Date of this First Amendment.

D. In view of the foregoing, the Borrower, the Lenders and the Administrative Agent mutually desire to amend certain aspects of the Credit Agreement to, among other things, (i) extend the Availability Period for three hundred sixty-four (364) days, and (ii) reflect the changes in the Arranger, Book Manager, Syndication Agent and Documentation Agent.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Borrower, the Lenders and the Administrative Agent hereby agree that the Credit Agreement shall be amended as follows:

1. Certain Definitions.

1.1 Terms Defined Above. As used in this First Amendment, the terms "Administrative Agent", "Borrower", "Credit Agreement", "Effective Date" and "First Amendment", shall have the meanings indicated above.

1.2 Terms Defined in Agreement. Unless otherwise defined herein, all terms beginning with a capital letter which are defined in the Credit Agreement shall have the same meanings herein as therein unless the context hereof otherwise requires.

2. Amendments to Credit Agreement.

2.1 Defined Terms. The following terms defined in Section 1.02 of the Credit Agreement are hereby amended as follows:

(a) The term "Agreement" is hereby amended to mean the Credit Agreement, as amended and supplemented by this First Amendment and as the same may from time to time be further amended or supplemented.

(b) The term "Conversion" is hereby amended in its entirety to read as follows:

> "`Conversion' means the conversion of the outstanding Revolving Loans to Term Loans pursuant to the terms and conditions of Section 2.01(d), which conversion shall occur on November 15, 2002, unless the Availability Period is extended pursuant to Section 2.01(c)."

2.2 Additional Defined Term. Section 1.02 of the Credit Agreement is hereby further amended and supplemented by adding the following new definition, which reads in its entirety as follows:

> "'First Amendment' shall mean that certain First Amendment and Supplement to Credit Agreement dated November 6, 2001, to be effective as of November 16, 2001, among the Borrower, the Lenders and the Administrative Agent."

2.3 Schedule 2.01 - Commitments. Schedule 2.01 attached to the Credit Agreement is hereby replaced and superseded by Schedule 2.01 attached to this First Amendment. From and after the Effective Date of this First Amendment, each Lender's Commitment shall be as set forth on Schedule 2.01 attached to this First Amendment.

3. Conditions Precedent. In addition to all other applicable conditions precedent contained in the Credit Agreement, the obligation of the Lenders and the Administrative Agent to enter into this First Amendment shall be conditioned upon the following conditions precedent:

(a) The Administrative Agent shall have received a copy of this First Amendment, duly completed and executed by the Borrower;

(b) The Administrative Agent shall have received such other information, documents or instruments as it or its counsel may reasonably request.

4. Default. Any default under this First Amendment shall constitute a default under the Credit Agreement.

5. Representations and Warranties. The Borrower represents and warrants to the Lenders and the Administrative Agent that:

(a) there exists no Default or Event of Default, or any condition or act which constitutes, or with notice or lapse of time or both would constitute, an Event of Default under the Credit Agreement, as hereby amended and supplemented;

(b) the Borrower has performed and complied with all covenants, agreements and conditions contained in the Credit Agreement, as hereby amended and supplemented, required to be performed or complied with by it; and

(c) the representations and warranties of the Borrower contained in the Credit Agreement, as hereby amended and supplemented, were true and correct when made, and are true and correct in all material respects at and as of the time of delivery of this First Amendment.

6. Extent of Amendments. Except as expressly herein set forth, all of the terms, conditions, defined terms, covenants, representations, warranties and all other provisions of the Credit Agreement are herein ratified and confirmed and shall remain in full force and effect.

7. Counterparts. This First Amendment may be executed in two or more counterparts, and it shall not be necessary that the signatures of all parties hereto be contained on any one counterpart hereof; each counterpart shall be deemed an original, but all of which together shall constitute one and same instrument.

8. References. On and after the Effective Date hereof, the terms "Agreement", "hereof", "herein", "hereunder", and terms of like import when used in the Credit Agreement shall, except where the context otherwise requires, refer to the Credit Agreement, as amended and supplemented by this First Amendment.

THIS FIRST AMENDMENT, THE CREDIT AGREEMENT, AS AMENDED HEREBY, THE NOTES AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES.

THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

This First Amendment shall benefit and bind the parties hereto, as well as their respective assigns, successors, heirs and legal representatives.

EXECUTED this 6/th/ day of November, 2001, effective as of the Effective Date.

BORROWER:

ENTERPRISE PRODUCTS OPERATING L.P.

By: Enterprise Products GP, LLC, General Partner

By: /s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Vice President and Treasurer

LENDERS AND AGENTS:

FIRST UNION NATIONAL BANK,
Individually and as Administrative Agent

By: /s/ Russell Clingman

Name: Russell Clingman
Title: Vice President

BANK ONE, NA (Main Office - Chicago),
Individually and as Co-Syndication Agent

By: /s/ Kenneth J. Fatur

Name: Kenneth J. Fatur
Title: Director, Capital Markets

THE BANK OF NOVA SCOTIA, Individually and as
Co-Syndication Agent

By: /s/ N. Bell

Name: N. Bell
Title: Assistant Agent

THE FUJI BANK, LIMITED, Individually and as
Managing Agent

By: /s/ Jacques Azagury

Name: Jacques Azagury
Title: Senior Vice President & Manager

FLEET NATIONAL BANK, Individually and as
Co-Documentation Agent

By: /s/ Christopher C. Holmgren

Name: Christopher C. Holmgren
Title: Managing Director

WESTDEUTSCHE LANDESBANK
GIRONZENTRALE, NEW YORK BRANCH,
Individually and as Co-Documentation Agent

By: /s/ Jeffrey S. Davidson /s/ Paul Verdi

Name: Jeffrey S. Davidson Paul Verdi
Title: Associate Director Manager

TORONTO DOMINION (TEXAS), INC.

By: /s/ Carolyn R. Faeth

Name: Carolyn R. Faeth
Title: Vice President

GUARANTY BANK

By: /s/ Jim R. Hamilton

Name: James R. Hamilton
Title: Senior Vice President

HIBERNIA NATIONAL BANK

By: /s/ Nancy G. Moragas

Name: Nancy G. Moragas
Title: Vice President

THE DAI-ICHI KANGYO BANK, LIMITED
Individually and as Managing Agent

By: /s/ Perzemek T. Blaziak

Name: Perzemek T. Blaziak
Title: Account Officer

BANK OF TOKYO-MITSUBISHI, LTD., HOUSTON AGENCY

By: /s/ K. Glasscock

Name: K. Glasscock
Title: VP & Manager

SUNTRUST BANK,
Individually and as Managing Agent

By: /s/ David J. Edge

Name: David J. Edge
Title: Director

CITIBANK, N.A.

By: /s/ Dougalas A. Whiddon

Name: Dougalas A. Whiddon
Title: Attorney-In-Fact

SCHEDULE 2.01

COMMITMENTS

Lender	Commitment
First Union National Bank	$15,875,000
Bank One, NA (Main Office - Chicago)	$15,000,000
Toronto Dominion (Texas), Inc.	$12,500,000
Fleet National Bank	$15,000,000
The Fuji Bank, Limited	$9,750,000
The Dai-Ichi Kangyo Bank, Limited	$5,250,000
Bank of Tokyo - Mitsubishi, Ltd., Houston Agency	$10,000,000
SunTrust Bank	$13,500,000
Westdeutsche Landesbank Girozentrale, New York Branch	$15,000,000
Guaranty Bank	$7,500,000
Citibank NA	$10,000,000
The Bank of Nova Scotia	$15,000,000
Hibernia National Bank	$5,625,000

EXHIBIT 12.1

ENTERPRISE PRODUCTS PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(dollars in millions)

	For Year Ended December 31,				
	2001	2000	1999	1998	1997
Income (loss) before minority interest and equity investments	$ 219.3	$ 198.6	$ 108.0	$ (5.5)	$ 37.0
Add:					
Fixed charges	59.4	43.7	24.4	21.5	37.6
Amortization of capitalized interest	0.2	0.2	0.1	0.1	0.1
Distributed income of equity investees	45.1	37.3	6.0	9.1	7.3
Less:					
Capitalized interest	(2.9)	(3.3)	(0.2)	(0.2)	(2.0)
Minority interest	(2.5)	(2.3)	(1.2)	(0.1)	(0.5)
Total Earnings	$ 318.6	$ 274.2	$ 137.1	$ 24.9	$ 79.5
Fixed charges:					
Interest expense	49.6	33.3	16.4	15.1	25.7
Capitalized interest	2.9	3.3	0.2	0.2	2.0
Interest portion of rental expense	6.9	7.1	7.8	6.2	9.9
Total	$ 59.4	$ 43.7	$ 24.4	$ 21.5	$ 37.6
Ratio of Earnings to Fixed charges	5.36x	6.27x	5.62x	1.15x	2.11x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items.

Add the following, as applicable:

- consolidated pre-tax income before minority interest and income or loss from equity investees;
- fixed charges;
- amortization of capitalized interest;
- distributed income of equity investees; and
- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the total of the added items, subtract the following, as applicable:

- interest capitalized
- preference security dividend requirements of consolidated subsidiaries; and
- minority interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following:

- interest expensed and capitalized;
- amortized premiums, discounts and capitalized expenses related to indebtedness;
- an estimate of interest within rental expenses (equal to one-third of rental expense); and
- preference security dividend requirements of consolidated subsidiaries.

EXHIBIT 21.1

Enterprise Products Partners L.P.
List of Subsidiaries of the Company

Enterprise Products Operating L.P., a Delaware limited partnership
Chunchula Pipeline Company, LLC, a Texas limited liability company
Cajun Pipeline Company, LLC, a Texas limited liability company
HSC Pipeline Partnership, L.P., a Texas limited partnership
Propylene Pipeline Partnership, L.P., a Texas limited partnership
Enterprise Products Texas Operating, L.P., a Texas limited partnership
Enterprise Lou-Tex Propylene Pipeline L.P., a Texas limited partnership
Enterprise Lou-Tex NGL Pipeline L.P., a Texas limited partnership
Enterprise NGL Private Lines & Storage LLC, a Delaware limited liability company
Enterprise NGL Pipelines, LLC, a Delaware limited liability company
Enterprise Gas Processing LLC, a Delaware limited liability company
Enterprise Norco LLC, a Delaware limited liability company
Enterprise Fractionation LLC, a Delaware limited liability company
Sabine Propylene Pipeline L.P., a Texas limited partnership
Sorrento Pipeline Company, LLC, a Texas limited liability company
Venice Pipeline LLC, a Delaware limited liability company
Grande Isle Pipeline LLC, a Delaware limited liability company
Acadian Gas LLC and subsidiaries, a Delaware limited liability company
Moray Pipeline Company, LLC, a Delaware limited liability company
Sailfish Pipeline Company, LLC, a Delaware limited liability company
EPOLP 1999 Grantor Trust, a trust formed under Texas law

EXHIBIT 23.1

INDEPENDENT AUDITOR'S CONSENT

We consent to the incorporation by reference in Enterprise Products Partners L.P. and Enterprise Products Operating L.P.'s (i) Registration Statement No. 333-36856 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-56082 of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. on Form S-3; and (iii) Registration Statement No. 333-82486 of Enterprise Products Partners L.P. on Form S-8 of our reports dated March 8, 2002, appearing in the respective Annual Reports on Form 10-K of Enterprise Products Partners L.P. and Enterprise Products Operating L.P. for the year ended December 31, 2001.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 21, 2002