UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K

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

For the fiscal year ended December 31, 2000 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 or 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 19, 2001, was approximately $348.5 million. This figure assumes that the directors and executive officers of the General Partner, the Enterprise Products 1998 Unit Option Plan Trust, Enterprise Products 2000 Rabbi Trust and the EPOLP 1999 Grantor Trust were affiliates of the Registrant.

The registrant had 45,524,515 Common Units outstanding as of March 22, 2001.

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	Acadian Gas, LLC
Aristech	Aristech Chemical Corporation and affiliates
Basell	Basell polyolefins and affiliates (formerly Montell)
Bcfd	Billion cubic feet per day
BEF	Belvieu Environmental Fuels, a joint venture of EPOLP
Belle Rose	Belle Rose NGL Pipeline LLC, a joint venture of EPOLP
BP	BP Amoco PLC and affiliates
BPD	Barrels per day
BRF	Baton Rouge Fractionators LLC, a joint venture of EPOLP
BRPC	Baton Rouge Propylene Concentrator, LLC, a joint venture of EPOLP
Btu	British thermal units
Burlington Resources	Burlington Resources Inc. and affiliates
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Company	Enterprise Products Partners L.P. and subsidiaries
Conoco	Conoco, Inc. and affiliates
Coral Energy	Coral Energy LLC, an affiliate of Shell
DIB	Deisobutanizer
Dixie	Dixie Pipeline Company, a joint venture of EPOLP
Duke Energy	Duke Energy Corporation and affiliates
Dynegy	Dynegy Inc. and affiliates
EBITDA	Earnings before Interest, Taxes, Depreciation and Amortization
Energy Policy Act	Energy Policy Act of 1992
Enron	Enron Corp. and affiliates
EPA	United States Environmental Protection Agency
EPCO	Enterprise Products Company, an affiliate of the Company
EPE	El Paso Energy Partners L.P. and affiliates
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively, a joint venture of EPOLP
EPOLP	Enterprise Products Operating L.P. (or "Operating Partnership"), a subsidiary of the Company
EPU	Earnings per Unit
Equistar	A joint venture of Lyondell Chemical Company, Millenium Chemicals, Inc. and Occidental Petroleum Corporation
ETBE	Ethyl Tertiary Butyl Ether
ExxonMobil	ExxonMobil Corporation and affiliates
FERC	Federal Energy Regulatory Commission
General Partner	Enterprise Products GP, LLC, the general partner of the Company and EPOLP
HLPSA	Hazardous Liquid Pipeline Safety Act
Huntsman	Huntsman Corporation and affiliates
ICA	Interstate Commerce Act
Kinder Morgan	Kinder Morgan Operating LP "A"
Koch	Koch Industries Inc. and affiliates
Lakehead	Lakehead Pipe Line Company
LIBOR	London Interbank Offering Rate
Manta Ray	Manta Ray Offshore Gathering Company, L.L.C.
MBA	Mont Belvieu Associates
MBA acquisition	Refers to the acquisition of an additional interest in the Mont Belvieu NGL fractionation facility from Kinder Morgan and EPCO effective July 1, 1999
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
Mitchell	Mitchell Energy and Development Corp. and affiliates

MLP	Denotes Enterprise Products Partners L.P. as guarantor of certain debt obligations of its Operating Partnership
MMBbls	Millions of barrels
Moray	Moray Pipeline Company, LLC
MTBE	Methyl tertiary butyl ether
Nautilus	Nautilus Pipeline Company, L.L.C.
Nemo	Nemo Gathering Company, L.L.C.
NGL or NGLs	Natural gas liquid(s)
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
Operating Partnership	Enterprise Products Operating L.P. and subsidiaries
OSHA	Occupational Safety and Health Act
Phillips	Phillips Petroleum Company and affiliates
Promix	K/D/S Promix LLC, a joint venture of EPOLP
PTR	Plant thermal reduction
PURPA	Public Utility Regulatory Policy Act of 1978
RCRA	Federal Resource Conservation and Recovery Act
Sailfish	Sailfish Pipeline Company, LLC
SEP	Shell Exploration and Production Company
SFAS	Statement of Financial Accounting Standards
SG&A	Selling, general and administrative costs
Shell	Shell Oil Company, its subsidiaries and affiliates
Stingray	Stingray Pipeline Company, LLC
Sun	Sunoco, Inc. and affiliates
TAME	Tertiary Amyl Methyl Ether
Tejas Energy	Tejas Energy, LLC, an affiliate of Shell
Texaco	Texaco Inc. and affiliates
TNGL	Tejas Natural Gas Liquids, LLC, a subsidiary of Tejas Energy
TNGL acquisition	Refers to the acquisition of TNGL from Shell effective August 1, 1999
Tri-States	Tri-States NGL Pipeline LLC, a joint venture of EPOLP
Ultramar Diamond	Ultramar Diamond Shamrock and affiliates
Valero	Valero Energy Corporation and affiliates
VESCO	Venice Energy Services Company, LLC, a joint venture of EPOLP
West Cameron	West Cameron Dehydration, LLC
Williams	Williams Companies, Inc. and affiliates
Wilprise	Wilprise Pipeline Company, LLC, a joint venture of EPOLP
1998 Trust	Enterprise Products 1998 Unit Option Plan Trust, an affiliate of EPCO
1999 Trust	EPOLP 1999 Grantor Trust, a wholly-owned subsidiary of EPOLP
2000 Trust	Enterprise Products 2000 Rabbi Trust, an affiliate of EPCO

PART I

Items 1 and 2. Business and Properties.

Summary

The Company is a leading integrated North American provider of natural gas processing and natural gas liquids fractionation, transportation and storage services to producers of NGLs and consumers of NGL products. The Company 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"), the Operating Partnership's subsidiaries, and a number of joint ventures with industry partners. The Company was formed in April 1998 to acquire, own, and operate all of the NGL processing and distribution assets of EPCO. The general partner of the Company, Enterprise Products GP, LLC, a majority-owned subsidiary of EPCO, holds a 1.0% general partner interest in the Company and a 1.0101% general partner interest in the Operating Partnership.

The principal executive office of the Company is located at 2727 North Loop West, Houston, Texas, 77008-1038, and the telephone number of that office is 713-880-6500. References to, or descriptions of, assets and operations of the Company in this document include the assets and operations of the Operating Partnership and its subsidiaries.

The Company (i) processes natural gas into a merchantable and transportable form of energy that meets industry quality specifications by removing NGLs and impurities; (ii) fractionates for a processing fee mixed NGLs produced as by-products of oil and natural gas production into their component products: ethane, propane, isobutane, normal butane and natural gasoline; (iii) converts normal butane to isobutane through the process of isomerization; (iv) produces MTBE from isobutane and methanol; and (v) transports NGL products to end users by pipeline and railcar. The Company also separates high purity propylene from refinery-sourced propane/propylene mix and transports high purity propylene to plastics manufacturers by pipeline. Products processed by the Company generally are used as feedstocks in petrochemical manufacturing, in the production of motor gasoline and as fuel for residential and commercial heating. Beginning in the first quarter of 2001, the Company will enter the natural gas pipeline business (see "Acquisitions" on page 2 of this Form 10-K).

The Company's NGL operations are concentrated in the Texas, Louisiana, and Mississippi Gulf Coast area. A large portion is concentrated in Mont Belvieu, Texas, which is the hub of the domestic NGL industry and is adjacent to the largest concentration of refineries and petrochemical plants in the United States. The facilities the Company operates at Mont Belvieu include: (a) one of the largest NGL fractionation facilities in the United States with a net processing capacity of 131 MBPD; (b) the largest commercial butane isomerization complex in the United States with a potential isobutane production capacity of 116 MBPD; (c) a MTBE production facility with a net production capacity of 5 MBPD; and (d) two propylene fractionation units with a combined production capacity of 31 MBPD. The Company owns all of the assets at its Mont Belvieu facility except for the NGL fractionation facility, in which it owns an effective 62.5% interest; one of the propylene fractionation units, in which it owns a 54.6% interest and controls the remaining interest through a long-term lease; the MTBE production facility, in which it owns a 33.3% interest; and one of its three isomerization units and one deisobutanizer which are held under long-term leases with purchase options.

The Company's operations in Louisiana and Mississippi include varying interests in twelve natural gas processing plants with a combined capacity of 11.6 Bcfd and net capacity of 3.2 Bcfd, six NGL fractionation facilities with a combined net processing capacity of 159 MBPD and a propylene fractionation facility with a net capacity of 7 MBPD.

The Company owns, operates or has an interest in approximately 65.0 million barrels of gross storage capacity (44.3 million barrels of net capacity) in Texas, Louisiana and Mississippi that are an integral part of its processing operations. The Company also leases and operates one of only two commercial NGL import/export terminals on the Gulf Coast. In addition, the Company has operating and non-operating ownership interests in over 2,900 miles of NGL pipelines.

The Company's operating margins are derived from services provided to its tolling customers and from merchant activities. In the Company's toll processing operations, it does not take title to the product and is simply paid a fee based on volumes processed, transported, stored or handled. The Company's profitability from toll processing operations depends primarily on the volumes of natural gas, NGLs and refinery-sourced propane/propylene mix processed and transported and the level of associated fees charged to its customers. In the Company's isobutane merchant activities and to a certain extent its propylene fractionation business, it takes title to feedstock products and sells processed end products. The Company's profitability from these merchant activities is dependent on the prices of feedstocks and end products, which may vary on a seasonal basis. In the Company's propylene fractionation business and isobutane merchant business, the Company generally attempts to match the timing and price of its feedstock purchases with those of the sales of end products so as to reduce exposure to fluctuations in commodity prices. The Company's operating margins from its natural gas processing business are generally derived from the margins earned on the sale of purity NGL products extracted from natural gas streams. To the extent it takes title to the NGLs removed from the natural gas stream and reimburses the producer for the reduction in the Btu content and/or the natural gas used as fuel (the "PTR" or "shrinkage"), the Company's margins are affected by the prices of NGLs and natural gas. The Company uses financial instruments to reduce its exposure to the change in the prices of NGLs and natural gas.

Uncertainty of Forward-Looking Statements and Information. This annual report on Form 10-K contains various forward-looking statements and information that are based on the belief of the Company and the General Partner, as well as assumptions made by and information currently available to the Company and the General Partner. When used in this document, words such as "anticipate," "estimate," "project," "expect," "plan," "forecast," "intend," "could," "believe," "would," "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 the Company and the General Partner believe that the expectations reflected in such forward-looking statements are reasonable, they can give no assurance that such expectations will prove to be correct. Such statements are subject to certain risks, uncertainties, and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual results may vary materially from those anticipated, estimated, projected, or expected.

Among the key risk factors that may have a direct bearing on the Company's results of operations and financial condition are: (a) competitive practices in the industries in which the Company competes, (b) fluctuations in oil, natural gas, and NGL product prices and production due to weather and other natural and market forces, (c) operational and systems risks, (d) environmental liabilities that are not covered by indemnity or insurance, (e) the impact of current and future laws and governmental regulations (including environmental regulations) affecting the NGL industry in general, and the Company's operations in particular, (f) loss of a significant customer, and (g) failure to complete one or more new projects on time or within budget.

In addition, the Company's expectations regarding its future capital expenditures as described in "Liquidity and Capital Resources" are only its forecasts regarding these matters. These forecasts may be substantially different from actual results due to the factors described in the previous paragraph as well as uncertainties related to the following: (a) the accuracy of the Company's estimates regarding its spending requirements, (b) the occurrence of any unanticipated acquisition opportunities, (c) the need to replace any unanticipated losses in capital assets, (d) changes in the strategic direction of the Company and (e) unanticipated legal, regulatory and contractual impediments with regards to its construction projects.

Acquisitions

Effective August 1, 1999, the Company acquired TNGL from Shell, in exchange for 14.5 million non-distribution bearing, convertible special partnership Units of the Company and $166 million in cash (the "TNGL acquisition"). The Company also agreed to issue up to 6.0 million additional non-distribution bearing special partnership Units to Shell in the future if the volumes of natural gas that the Company processes for Shell reach agreed upon levels in 2000 and 2001. The first 3.0 million of these additional special partnership Units were issued on August 1, 2000. The businesses acquired from Shell include natural gas processing and NGL fractionation, transportation and storage in Louisiana and Mississippi and its NGL supply and merchant business.

The assets acquired include varying interests in eleven natural gas processing plants, four NGL fractionation facilities, four NGL storage facilities, operator and non-operator ownership interests in approximately 1,500 miles of NGL pipelines and a 20-year natural gas processing agreement with Shell.

The Company has recently announced and/or completed the acquisition of three Louisiana-based natural gas pipeline systems:

- Acadian Gas, LLC ("Acadian") for $226 million;
- Stingray Pipeline Company, LLC ("Stingray") and West Cameron Dehydration, LLC ("West Cameron") for approximately $25.1 million; and
- Sailfish Pipeline Company, LLC ("Sailfish") and Moray Pipeline Company, LLC ("Moray") for approximately $88.1 million.

The Company has executed a definitive agreement with the seller of Acadian with closing expected in the first quarter of 2001. The Stingray, West Cameron, Sailfish and Moray acquisitions closed on January 29, 2001. The acquisition of these natural gas pipeline systems represents a strategic investment for the Company and allows for entry into the natural gas gathering, transportation, marketing and storage business. Management believes 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 the Company's midstream energy service relationship with long-term NGL customers (producers, petrochemical suppliers and refineries) and offer additional fee-based cash flows and opportunities for enhanced services to customers. For additional information regarding these 2001 acquisitions, see page 12 of this Form 10-K.

The Company will continue to analyze potential acquisitions, joint ventures or similar transactions with businesses that operate in complementary markets and geographic regions. In recent years, major oil and gas companies have sold non-strategic assets including assets in the midstream natural gas industry in which the Company operates. Management believes that this trend will continue, and the Company expects independent oil and natural gas companies to consider similar options.

The Company's Operations

The Company's operations are segregated into five reportable business segments:

- Fractionation
- Pipeline
- Processing
- Octane Enhancement
- Other

The Fractionation segment is primarily comprised of the following three business areas: NGL Fractionation, Isomerization and Propylene Fractionation. The Fractionation segment also includes the Company's equity method investments in BRF, BRPC and Promix. In addition, this segment includes the support facilities for the NGL Fractionation, Isomerization and Propylene Fractionation facilities and other miscellaneous minor plants. Pipelines includes the Company's pipeline systems, storage facilities and the Houston Ship Channel Import/Export terminal. The Pipeline segment also includes the Company's equity method investments in EPIK, Wilprise, Tri-States, Belle Rose and Dixie. The Processing segment consists of the Company's natural gas processing business and related merchant activities. Octane Enhancement is comprised of the Company's equity interest in BEF, which owns and operates a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other segment is primarily comprised of fee-based marketing services and other operational support activities including engineering and plant-based information technology functions.

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

The Company's NGL Fractionation operations include seven NGL fractionators with a combined gross processing capacity of 558 MBPD and net processing capacity of 290 MBPD. A summary of the Company's NGL fractionation facilities at December 31, 2000 is as follows:

NGL Fractionation Facility	Location	Gross Capacity (MBPD)	Ownership Interest	Net Capacity (MBPD)
Mont Belvieu	Texas	210	62.5%	131
Norco	Louisiana	70	100.0%	70
BRF	Louisiana	60	32.2%	19
Promix	Louisiana	145	33.3%	48
Tebone	Louisiana	30	33.4%	10
Venice	Louisiana	36	13.1%	5
Petal	Mississippi	7	100.0%	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 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 and 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 in 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 motor gasoline blend stock or 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 in the field, mixed NGLs are transported to a centralized facility for fractionation. Mixed NGL recovery by gas processing plants represents the most important source of throughput for the Company's NGL fractionators and is generally governed by the degree to which NGL prices exceed the cost (principally that of natural gas as a raw material feedstock and as a fuel) of separating the mixed NGLs from the purified 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 in fractionation, mixed NGL recovery levels by these facilities (and hence NGL fractionation volumes) may be reduced. For a complete discussion of the Company's gas plants, see Processing on page 14 of this Form 10-K. 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 domestic crude oil refineries to the Company's NGL fractionation facilities are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck. The Company takes delivery of mixed NGL imports through its Houston ship channel NGL import/export facility which is connected to Mont Belvieu via pipeline.

In general, the Company's NGL fractionation business processes mixed NGL streams for a toll processing fee charged to its third-party and merchant business customers. Overall, results of operations of this business area are dependent upon the volume of mixed NGLs processed and the level of toll processing fees charged to customers and exhibit little to no seasonal variation. NGL fractionation toll processing 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 in NGL fractionation. The NGL fractionation revenues earned from the Company's related merchant business are based primarily on the mixed NGL volumes flowing from Company and affiliate-owned gas processing plants. Lastly, NGL producers generally retain title to, and the pricing risks associated with, the NGL products.

Management believes that sufficient volumes of mixed NGLs, especially those originating from the Company's and/or its affiliate's 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. In addition, significant volumes of mixed NGLs are contractually committed to the Company's facilities by third-party customers.

NGL Fractionation Facilities

During 2000, the Company's NGL fractionation facilities processed mixed NGLs at an average rate of 213 MBPD or 73% of capacity, both amounts on a net basis. The table below shows net processing volumes and capacity (both in MBPD) and the corresponding overall utilization rates of the Company's NGL fractionation facilities for the last three years:

NGL Fractionation Facility	For Year Ended December 31, 2000	1999	1998
Mont Belvieu (a)	106	78	71
Norco	47	48	-
BRF	15	13	-
Promix	34	30	-
Other (b)	11	15	2
Total Processing Volume	213	184	73
Net Capacity (c)	290	264	86
Utilization	73%	70%	85%

(a) Net volumes increased in 1999 and 2000 due to increased ownership of facilities resulting from the MBA acquisition in July 1999
(b) Includes Venice, Tebone and Petal NGL fractionation facilities
(c) Capacities have been adjusted for acquisitions

Mont Belvieu NGL Fractionation facility. The Company operates one of the largest NGL fractionation facilities in the United States with a gross processing capacity of 210 MBPD at Mont Belvieu, Texas (approximately 25 miles east of Houston). 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. The Company owns an effective 62.5% interest in the NGL fractionation facilities at the Mont Belvieu complex.

At the Mont Belvieu NGL fractionation facilities, the Company has long-term fractionation agreements with Burlington Resources, Texaco and Duke Energy each of which is a significant producer of NGLs and a co-owner of the Mont Belvieu NGL fractionation facility. Burlington Resources and Texaco have agreed to deliver either a minimum of 39 MBPD of mixed NGLs or all of their mixed NGLs brought within 50 miles of the Mont Belvieu facility. Duke Energy has agreed to deliver 26 MBPD of mixed NGLs to Mont Belvieu as well as additional barrels that exceed its commitments to other NGL fractionation facilities. The Company generally enters into contracts that cover most of the remaining capacity at the Mont Belvieu facilities for one to three-year terms with customers that are producers and/or consumers of NGLs.

In January 2001, the Company entered into a five-year agreement to exchange NGLs produced at the Sea Robin natural gas processing plant for finished NGL products at the Company's Mont Belvieu complex. The NGLs will be exchanged via the Company's recently completed Lou-Tex NGL Pipeline (see page 11 for information regarding this pipeline). As a result of this agreement, the Company will utilize its Mont Belvieu NGL fractionation facility to process the mixed NGLs received from the Sea Robin plant into finished NGL products. Initial net processing volumes are expected to be 10 MBPD and are anticipated to increase to over 13 MBPD by the end of 2001.

Norco NGL Fractionation facility. The Company owns and operates a NGL fractionation facility at Norco, Louisiana. The Norco facility receives mixed NGLs via pipeline from the Yscloskey, Toca, Paradis and Crawfish gas processing plants and has an average processing capacity of 70 MBPD.

BRF NGL Fractionation facility. The Company operates and has a 32.2% interest in BRF, which owns a 60 MBPD NGL fractionation facility and related transportation assets located near Baton Rouge, Louisiana. The BRF facility processes mixed NGLs received from BP, ExxonMobil and Williams, all of which are partners with the Company in BRF, through long-term fractionation agreements. The mixed NGLs provided by the partners originate from Alabama, Mississippi and southern Louisiana including offshore Gulf of Mexico areas.

Promix NGL Fractionation facility. The Company operates and has a 33.3% 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 salt dome storage wells which handle mixed NGLs, propane, isobutane, normal butane and natural gasoline and a barge loading facility. Promix receives mixed NGLs from gas processing plants located in southern Louisiana.

Tebone NGL Fractionation facility. The Company operates and has a 33.4% interest in a captive NGL fractionation facility located near Geismar, Louisiana. This facility serves the Company's gas processing facilities in North Terrebonne, Louisiana and has a gross processing capacity of 30 MBPD.

Venice NGL Fractionation facility. The Company has a 13.1% interest in VESCO, which owns a captive 36 MBPD NGL fractionation facility located near Venice, Louisiana. This facility serves VESCO's gas processing operations located in southern Louisiana and is operated by Dynegy.

Petal NGL Fractionation facility. The Company owns and operates a NGL fractionation facility at Petal, Mississippi with a processing capacity of 7 MBPD. The Petal plant is connected to the Company's Chunchula pipeline system and serves NGL producers in Mississippi, Alabama and Florida.

Isomerization

The Company's isomerization facilities include three butamer reactor units and eight associated DIBs located in Mont Belvieu, Texas which comprise the largest commercial isomerization complex in the United States. The Company's facilities have an average combined potential production capacity of 116 MBPD of isobutane and account for more than 70% of the commercial isobutane production capacity in the United States. The Company owns the isomerization facilities with the exception of one of the butamer reactor units, which it holds through a long-term lease. The facilities are operated by the Company. During the second quarter of 2000, the Company refurbished one of its butamer reactors that had been shut down since July 1999 resulting in improved operational flexibility during periods of excess demand. This unit, accounting for 36 MBPD of capacity, was active only during the second quarter of 2000. The following table shows isobutane production and capacity (both in MBPD) and overall utilization for the last three years:

	For Year Ended December 31,		
Mont Belvieu Facility	2000	1999	1998
Production	74	74	67
Capacity (a)	86	98	116
Utilization	86%	76%	58%

(a) The 1999 capacity figure reflects Isom II (36 MBPD of capacity) being shutdown for the last half of the year. The 2000 capacity has been adjusted for the two months that Isom II ran during the early summer and its subsequent placement into standby status thereafter.

Commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into isobutane and normal butane. The demand for commercial isomerization services depends upon the industry's requirements for (i) isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations and (ii) high purity isobutane. 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 operations of this business area are generally dependent upon the volume of normal and mixed butanes processed and the level of processing fees charged to customers. The principal uses of isobutane are for alkylation and in the production of MTBE and propylene oxide.

The Company uses its isomerization facilities to convert normal butane into isobutane for its toll processing customers, including its isobutane merchant business. The Company's largest third-party toll processing customers operate under long-term contracts under which they supply normal butane feedstock and pay the Company a toll processing fee based on the volume of isobutane produced. The largest of these customers in 2000 were Lyondell, Huntsman, Sun and Mitchell. Sun and Mitchell use the high purity isobutane produced for them to meet their feedstock obligations as partners in the BEF MTBE facility. The Company also meets its obligation to provide high purity isobutane feedstock to the BEF MTBE facility with production from the isomerization units. During 2000, 59 MBPD of isobutane production was attributable to third-party toll processing customers.

The balance of isobutane production during 2000, or 15 MBPD, relates to merchant activities associated with isobutane sales contracts. In general, the merchant business (which is part of the Processing segment) meets the requirements of its isobutane sales contracts by either purchasing isobutane in the spot market or paying the isomerization business to process Company-held inventories of normal and/or mixed butanes. The isomerization business area collects a toll processing fee from the merchant business based on the volume of normal and mixed butanes processed. The normal and mixed butane inventories are primarily derived from imports and NGL fractionation operations. Management believes that it will have access to sufficient volumes of normal and mixed butanes in the foreseeable future to meet the needs of its isobutane merchant activities. For a further discussion of the Company's merchant activities, see Processing on page 14 of this Form 10-K.

Propylene Fractionation

The Company's propylene fractionation business consists of two polymer grade propylene facilities (Splitters I and II) and one chemical grade propylene plant (BRPC) with a combined gross production capacity of 54 MBPD and a net capacity of 38 MBPD. The following table summarizes the propylene fractionation business assets at December 31, 2000:

Propylene Facility	Location	Gross Capacity (MBPD)	Ownership Interest	Net Capacity (MBPD)
Splitter I (a)	Texas	17	100.0%	17
Splitter II	Texas	14	100.0%	14
BRPC	Louisiana	23	30.0%	7
	Total	54		38

(a) The Company owns 54.6% with Basell owning the remaining 45.4%. The Company leases Basell's interest.

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 is derived by processing either refinery grade or chemical grade propylene feedstocks. Approximately one-half 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 produced either as a by-product of olefin (ethylene) plants or from the processing of refinery grade propylene. Chemical grade propylene is a basic petrochemical used in plastics, synthetic fibers and foams.

During 2000, the Company's propylene fractionation facilities produced at an average rate of 33 MBPD or 94% 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 the Company's propylene fractionation facilities for the last three years:

Facility	For Year Ended December 31, 2000	1999	1998
Splitter I & II	29	28	26
BRPC	4	-	-
Total	33	28	26
Capacity (a)	35	31	31
Utilization	94%	90%	84%

(a) 2000 capacity adjusted for start-up of BRPC unit in July 2000

Splitter I and II Propylene Fractionation facilities. The Company operates two polymer grade propylene fractionation facilities at Mont Belvieu, Texas with a gross capacity of 31 MBPD. The Company owns 54.6% of Splitter I and 100.0% of Splitter II. The Company leases the remaining 45.4% interest in Splitter I from a customer, Basell (formerly Montell).

Results of operations for the Company's polymer grade propylene plants are generally dependent upon (i) long-term toll processing arrangements and (ii) merchant activities. The Company's largest toll processing customers during 2000 were Equistar and Huntsman. In general, pursuant to contracts with these companies, the Company is guaranteed certain minimum volumes and paid a toll processing fee based on the throughput of refinery grade propylene used to produce polymer grade propylene. In the Company's propylene merchant business, the Company has several long-term polymer grade propylene sales agreements, the largest of which is with Basell. The Basell agreement stipulates that the Company will sell a certain quantity of polymer grade propylene to Basell at market-based prices through 2004. In order to meet its merchant obligations, the Company has entered into several long-term agreements to purchase refinery grade propylene. The Company reduces the commodity price exposure in the merchant portion of this business by matching the volumes and pricing mechanisms required under sales contracts with its supply contracts. During 2000, 12 MBPD of polymer grade propylene production was associated with toll processing operations while 17 MBPD was attributable to merchant activities.

The Company is able to unload barges carrying refinery grade propylene through its import/export terminal located on the Houston ship channel. The Company is also able to receive supplies of refinery grade propylene from its Mont Belvieu truck and rail loading facility and from refineries and other producers through its pipeline located along the Houston ship channel. In turn, polymer grade propylene is shipped to customers by truck or pipeline. Both toll processing demand and merchant requirements are generally constant throughout the year and exhibit little seasonality, except to the extent that either of the facilities is impacted by downtime attributable to maintenance and/or economic reasons.

BRPC Propylene Fractionation facility. The Company operates and owns a 30.0% interest in BRPC, which owns a 23 MBPD chemical grade propylene production facility located near Baton Rouge, Louisiana. The unit, located across the Mississippi River from ExxonMobil's refinery and chemical plant, fractionates refinery grade propylene produced by ExxonMobil into chemical grade propylene for a toll processing fee. Results of operations of BRPC are dependent upon the volume of refinery grade propylene throughput and the level of toll processing fees charged. Due to the relatively consistent flow of feedstock and fixed-nature of the toll processing fees charged, results of operations for BRPC exhibit little seasonality (except to the extent that volumes are affected by downtime associated with maintenance or other economic reasons). The BRPC facility commenced operations in the third quarter of 2000 and averaged 4 MBPD (on an net basis) of chemical grade propylene production during the period in which it was operational.

Pipeline

The Company's Pipeline segment includes its ownership interests in a 2,942-mile network of transportation and distribution pipeline systems and related hydrocarbon storage facilities and import/export assets. At December 31, 2000, the Company's major pipeline systems were as follows:

Major NGL & Petroleum Liquid Pipeline Systems	Miles
Dixie Pipeline	1,301
Louisiana Pipeline System	471
Lou-Tex Propylene Pipeline System	291
Tri-States, Belle Rose and Wilprise Pipeline Systems	247
Lou-Tex NGL Pipeline System	206
Houston Ship Channel Pipeline System	175
Lake Charles/Bayport Propylene Pipeline System	134
Chunchula Pipeline System	117
Total Major Pipeline Systems	2,942

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, total pipeline throughput averaged 367 MBPD in 2000, 264 MBPD in 1999 and 200 MBPD in 1998 (all amounts on a net basis).

Description	For Year Ended December 31, 2000	1999	1998
Dixie Pipeline	14	14	-
Louisiana Pipeline System	115	74	40
Lou-Tex Propylene Pipeline System (a)	23	-	-
Tri-States, Belle Rose and Wilprise Pipeline Systems	42	41	-
Lou-Tex NGL Pipeline System (b)	30	-	-
Houston Ship Channel Pipeline System	106	99	107
Lake Charles/Bayport Propylene Pipeline System	5	5	7
Chunchula Pipeline System	6	7	5
EPIK Export Facility (c)	17	10	10
Houston Ship Channel NGL import facility	9	14	31
Total Throughput MBPD	367	264	200

(a) Volumes reflect the period in which the Company owned the asset (i.e., March 2000 through December 2000)
(b) Pipeline commenced operations in late November 2000
(c) 2000 volumes higher than 1999 due to installation of new NGL product chiller unit in the fourth quarter of 1999

The Company's pipelines transport mixed NGLs and liquid hydrocarbons to the Company's NGL fractionation plants; distribute NGL purity products and propylene to petrochemical plants and refineries; and deliver propane to customers along the 1,301-mile Dixie pipeline. The pipelines provide transportation services to customers on a fee basis. As such, results of operations for this business area are generally dependent upon the volume of product transported and the level of fees charged to customers (which include the Company's 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 the 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.

The Company's hydrocarbon storage facilities and NGL import/export terminal are integral parts of its pipeline operations. In general, storage wells are used to store mixed NGLs and refinery grade propylene that have been delivered to Company facilities for processing. Such storage allows the Company to mix various batches of feedstock and maintain a sufficient supply and stable composition of feedstock to its processing facilities. The Company also uses the wells to store certain fractionated products for its customers when they are unable to take immediate delivery. The profitability of storage operations is primarily dependent upon the volume of material stored and the level of storage fees charged to customers. Some of the Company's processing contracts allow for a short period of free storage (typically 30 days or less) and impose fees based on volumes stored for longer periods. Intersegment revenues for the Pipeline segment include those fees charged to the Company's various merchant businesses for use of the storage facilities. The Company owns and operates storage wells at Mont Belvieu, Texas with an aggregate capacity of 21 MMBbls (including the recent purchase of a storage well from Equistar mentioned below under "Major Pipeline Acquisitions in 2001"). The Company's Louisiana storage assets consist of facilities located at or near Breaux Bridge, Napoleonville, Sorrento and Venice having a gross capacity of 33 MMBbls and a net capacity of 14.8 MMBbls. The Company's Mississippi storage assets are comprised of facilities located at or near Petal and Hattiesburg, Mississippi with a gross capacity of 12 MMBbls and a net capacity of 9.5 MMBbls. Of the facilities located in Louisiana and Mississippi, the Company operates those located in Breaux Bridge, Louisiana and Petal, Mississippi. Koch, Dynegy and Equilon (an affiliate of Shell) operate the remaining facilities.

The Company leases and operates a NGL import facility at the Oiltanking Houston marine terminal on the Houston ship channel that enables NGL tankers to be offloaded at their maximum unloading rate (10,000 barrels per hour), thus minimizing laytime and increasing the number of vessels that can be offloaded. A methanol pipeline, which is part of the Houston Ship Channel Pipeline System, extends from the import facility to Mont Belvieu and enables methanol to be delivered by ship or barge and then transported to the Company's MTBE facility at Mont Belvieu where it is consumed in the MTBE process. In addition, the Company owns a combined 50% interest in EPIK, a joint venture with Idemitsu, which owns NGL export assets at the terminal including a NGL product chiller and related equipment used for loading refrigerated marine tankers. The NGL product chiller speeds the loading of tankers at rates up to 5,000 barrels per hour of refrigerated propane and butane, one of the highest loading rates in the United States. Traditionally, EPIK's export volumes are higher during the winter months due to increased propane exports by Idemitsu and other parties. The profitability of import and export activities depends primarily upon the volumes unloaded and loaded and the level of fees associated with each activity.

Major Pipeline Systems

Dixie Pipeline. The Dixie Pipeline is a 1,301-mile propane pipeline which moves propane supplies from Mont Belvieu, Texas and Louisiana to markets in the southeastern United States. At December 31, 2000, the Company owned a 19.9% interest in Dixie (with 8.4% of its interest being purchased from Conoco for $19.4 million in October 2000). The other owners of Dixie are BP, Chevron, ExxonMobil, Phillips and Texaco with Phillips serving as operator.

Louisiana Pipeline System. The Louisiana Pipeline System is a 471-mile Company-owned 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 the Company's gas processing and other facilities located in the Louisiana area. The Company operates 233 miles of the system, and Equilon operates the remainder.

Lou-Tex Propylene Pipeline System. 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. The purchase of this system, effective March 1, 2000 from Concha Chemical Pipeline Company (an affiliate of Shell), was completed at a cost of approximately $100 million. The Company owns and operates these assets.

Tri-States, Belle Rose and Wilprise Pipeline Systems. The Company is participating in pipeline joint ventures which supply mixed NGLs to the BRF and Promix NGL fractionators. They are as follows:

- The Company owns a 33.3% interest in Tri-States, which owns a 169-mile NGL pipeline that extends from Mobil Bay, Alabama to near Kenner, Louisiana. Tri-States is a joint venture with BP, Duke Energy, Koch and Williams with Williams acting as operator of the assets.
- The Company operates and owns a 41.7% interest in Belle Rose, which owns a 48-mile NGL pipeline that extends from near Kenner, Louisiana to the Promix NGL fractionation facility in Napoleonville, Louisiana. Belle Rose is a joint venture with Gulf Coast NGL Pipeline and Koch.
- The Company owns a 37.4% interest in Wilprise, which owns a 30-mile NGL pipeline that extends from near Kenner, Louisiana to Sorrento, Louisiana. Wilprise is a joint venture with Williams and BP with Williams acting as operator of the assets.

Lou-Tex NGL Pipeline System. The Lou-Tex NGL Pipeline System consists of a recently completed 206-mile NGL pipeline used (i) to provide transportation services for NGL products and refinery grade propylene between the Louisiana and Texas markets and (ii) to transport mixed NGLs from the Company's Louisiana gas processing facilities to the Mont Belvieu NGL fractionation facility. Construction of this system was completed during the fourth quarter of 2000 at a cost of approximately $87.9 million. The Company operates and owns the system.

Houston Ship Channel Pipeline System. The Houston Ship Channel Pipeline System is a collection of NGL and petrochemical pipelines aggregating 175 miles in length used to deliver feedstocks to Company facilities for processing and to deliver products to petrochemical plants and refineries. This system also connects the Company's Mont Belvieu facilities to its NGL import/export terminal located on the Houston ship channel. This system extends west from Mont Belvieu and runs along the Houston ship channel to Pierce Junction, which is south of Houston, Texas. Beginning in April 2001, management anticipates that this pipeline system will be used to transport to the Oiltanking Houston marine terminal approximately 15 MBPD of MTBE production from the BEF facility that had been previously transported by a third-party pipeline system. The Company operates and owns this pipeline system.

Lake Charles/Bayport Propylene Pipeline System. The Lake Charles/Bayport Propylene Pipeline System is a 134-mile propylene pipeline system used to distribute polymer grade propylene from Mont Belvieu to Basell's polypropylene plants in Lake Charles, Louisiana and Bayport, Texas and Aristech's facility in LaPorte, Texas. A segment of the pipeline is jointly owned by the Company and Basell, and another segment of the pipeline is leased from ExxonMobil.

Chunchula Pipeline System. The Chunchula Pipeline System is a 117-mile NGL pipeline system extending from the Alabama-Florida border to the Company's storage and NGL fractionation facilities near Petal, Mississippi. The system gathers NGLs from production areas in Florida and Alabama and delivers them to the Petal NGL fractionation facility for processing or storage and further distribution. The Company owns and operates this pipeline.

Major Pipeline Acquisitions in 2001

The Company has recently announced and/or completed the acquisition of three Louisiana-based natural gas pipeline systems:

- Acadian Gas, LLC ("Acadian");
- Stingray Pipeline Company, LLC ("Stingray") and West Cameron Dehydration, LLC ("West Cameron"); and
- Sailfish Pipeline Company, LLC ("Sailfish") and Moray Pipeline Company, LLC ("Moray").

The acquisition of these natural gas pipeline systems represents a strategic investment for the Company and allows for entry into the natural gas gathering, transportation, marketing and storage business. Management believes 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 the Company's midstream energy service relationship with long-term NGL customers (producers, petrochemical suppliers and refineries) and offer additional fee-based cash flows and opportunities for enhanced services to customers.

Acadian. On September 25, 2000, the Company announced that it had executed a definitive agreement to purchase Acadian from Coral Energy, an affiliate of Shell, for $226 million in cash, inclusive of working capital. The acquisition of Acadian integrates its natural gas pipeline systems in South Louisiana with the Company's Gulf Coast natural gas processing and NGL fractionation, pipeline and storage system. The Acadian acquisition gives the Company an extensive intrastate natural gas pipeline system with access to both supply and markets; positions the Company to compete for incremental natural gas supplies from new discoveries onshore, the offshore Louisiana continental shelf and Gulf of Mexico deepwater developments; and enables the Company to take advantage of growing industrial and petrochemical demand (including new gas-fired power generation projects) along with additional natural gas processing opportunities.

Acadian's assets are comprised of the 438-mile Acadian, 577-mile Cypress and 27-mile Evangeline natural gas pipeline systems, which together have over 1.0 Bcfd of capacity. These natural gas pipeline systems are wholly-owned by Acadian with the exception of the Evangeline system in which Acadian holds an approximate 49.5% interest. The system includes a leased natural gas storage facility at Napoleonville, Louisiana. Completion of this transaction is subject to certain conditions, including regulatory approvals. The purchase is expected to be completed during the first quarter of 2001.

Stingray, West Cameron, Sailfish and Moray (collectively, the "El Paso acquisition"). On January 29, 2001, the Company completed the purchase of 50% of the membership interests of Stingray and West Cameron, together with some offshore lateral pipelines for approximately $25.1 million in cash from affiliates of El Paso Energy Partners L.P. ("EPE") and Coastal Corp. Shell purchased the remaining 50% membership interests of both Stingray and West Cameron for an equal amount of cash. In addition, the Company purchased from EPE 100% of the membership interests of Sailfish and Moray for approximately $88.1 million in cash.

Collectively, the Company acquired interests in five natural gas gathering and transmission pipeline systems in the Gulf of Mexico totaling approximately 737 miles of pipeline with an aggregate gross capacity of 2.85 Bcfd. These pipelines and their associated assets are strategically located to serve continental shelf and deepwater developments in the central Gulf of Mexico. As with the Acadian acquisition, the El Paso acquisition broadens the Company's midstream business by providing additional services to customers, and it benefits from increased natural gas production from deepwater Gulf of Mexico development. Management believes that the assets acquired from EPE complement and integrate well with those of the Acadian acquisition.

Stingray owns a 375-mile FERC-regulated two phase natural gas pipeline system that transports natural gas and injected condensate from the High Island, West Cameron, East Cameron, Vermillion and Garden Banks areas in the Gulf of Mexico to onshore transmission systems at Holly Beach and Cameron Parish, Louisiana. West Cameron is an unregulated dehydration facility located at and connected to the onshore terminal of Stingray. Shell is the operator of the Stingray and West Cameron facilities.

Sailfish owns a 25.67% interest in Manta Ray Offshore Gathering Company, L.L.C. ("Manta Ray") and Nautilus Pipeline Company, L.L.C. ("Nautilus"). Moray owns a 33.92% interest in the Nemo Gathering Company, L.L.C. ("Nemo"). Manta Ray (which is jointly owned by Sailfish, Shell and Marathon Gas Transmission Company Inc.) owns 237 miles of unregulated natural gas transmission lines primarily located on the outer continental shelf offshore Louisiana. Nautilus (which is owned by Sailfish, Shell and Marathon Gas Transmission Company Inc.) owns 101 miles of FERC-regulated natural gas pipelines and related facilities extending from points offshore Louisiana to interconnecting pipelines near the Garden City and Neptune gas processing facilities. Nemo (which is jointly owned by Moray and Shell) is a development stage enterprise that is constructing and will operate an offshore Louisiana natural gas gathering pipeline and related facilities that will connect certain Shell offshore platform assets to Manta Ray. Management believes that these assets have a significant upside potential, since Shell and Marathon have dedicated production from over 1,000 square miles of offshore natural gas leases to these systems and only a small portion of this total has been developed to date. Shell is the operator of the Manta Ray, Nautilus and Nemo systems.

Equistar storage facility. In addition to the natural gas pipeline acquisitions, the Company announced on February 1, 2001 that it had acquired a NGL storage facility from Equistar Chemicals, LP for approximately $3.4 million. The salt dome storage cavern, which is located near the Company's Mont Belvieu, Texas complex, has a capacity of one million barrels. The purchase also includes adjacent acreage which would support the development of additional storage capacity.

Processing

The Company's Processing segment consists of its natural gas processing business and related merchant activities. At the core of the Company's natural gas processing business are twelve natural gas processing plants located on the Louisiana and Mississippi Gulf Coast with gross natural gas processing capacity of 11.61 Bcfd or net capacity of 3.21 Bcfd based on the Company's current ownership interest. The NGL production from these facilities, along with that from the Mont Belvieu isomerization facilities, supports the merchant activities included in this operating segment.

The following table lists the natural gas processing facilities in which the Company has an ownership interest:

Gas Processing Facility	Location	Gross Gas Processing Capacity (Bcf/day)	Net Gas Processing Capacity (Bcf/day)	Company Ownership Interest in Facility	Operator
Yscloskey	St. Bernard Parish, Louisiana	1.85	0.60	32.6%	Dynegy
Calumet	St. Mary Parish, Louisiana	1.60	0.57	35.4%	EPOLP
North Terrebonne	Terrebonne Parish, Louisiana	1.30	0.43	33.4%	EPOLP
Venice	Plaquemines Parish, Louisiana	1.30	0.17	13.1%	Dynegy
Toca	St. Bernard Parish, Louisiana	1.10	0.61	55.5%	EPOLP
Pascagoula	Pascagoula, Mississippi	1.00	0.40	40.0%	BP
Sea Robin	Vermillion Parish, Louisiana	0.95	0.06	6.4%	Texaco
Blue Water	Acadia Parish, Louisiana	0.95	0.07	7.4%	ExxonMobil
Iowa	Jefferson Davis Parish, Louisiana	0.50	0.01	2.0%	Texas Eastern
Patterson II	St. Mary Parish, Louisiana	0.60	0.01	2.0%	Duke Energy
Neptune	St. Mary Parish, Louisiana	0.30	0.20	66.0%	EPOLP
Burns Point	St. Mary Parish, Louisiana	0.16	0.08	50.0%	Marathon
	Total Gas Processing Capacity	11.61	3.21		

The Company's 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 plant owners to extract NGLs from a natural gas stream when the market value of the NGLs is higher than the market value of the same unprocessed natural gas. After extraction, mixed NGLs are typically transported 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 the Company in its merchant activities to meet contractual requirements or sold on the spot and forward markets.

The Venice gas plant is part of a larger processing complex owned by VESCO. Along with the Venice gas plant, VESCO owns a NGL fractionation facility (previously mentioned under the Fractionation segment), storage assets and gas gathering pipelines located in Louisiana. The other owners of VESCO are Chevron, Koch, Venice Gathering and Dynegy. The Company owns 13.1% of VESCO.

The natural gas throughput capacities of the gas processing facilities are based on practical limitations. The Company's utilization of the gas processing assets depends upon general economic and operating conditions and is generally measured in terms of equity NGL production. Production of NGLs is generally a function of throughput (i.e., higher natural gas throughput rates translate into higher equity NGL production). Equity NGL production can be defined as the volume of NGLs extracted by the gas processing plants to which the Company takes title under the terms of its processing agreements or as result of plant ownership interests. Equity NGL production can be negatively affected by high fuel costs and/or low purity NGL product prices.

The Company's equity NGL production was 72 MBPD in 2000 compared with 67 MBPD in 1999. For comparison purposes only, Shell equity NGL production from these facilities was 41 MBPD in 1998. The 1999 volume is for the period the

Company owned the assets after the TNGL acquisition. For the entire year of 1999, equity NGL production (for both Shell and the Company) from the facilities was 57 MBPD. The increase in equity production from 1999 to 2000 is due to growing levels of natural gas production available for processing, higher NGL content natural gas and new processing facilities, such as the Company's Neptune plant. The increase in equity production from 1998 to 1999 is attributable to increased Gulf of Mexico deepwater production, the start-up of the Pascagoula facility in 1999 and improved market prices for NGLs which justified higher extraction rates.

Management believes that natural gas and associated NGL production from the Gulf of Mexico will significantly increase in the coming years as a result of advances in three-dimensional seismic and development systems and continued capital spending by major oil companies regardless of the commodity environment.

The majority of the operating margins earned by the Company's natural gas processing operations are based on the relative economic value of the NGLs extracted by the gas plants compared to the fuel and shrinkage value of the natural gas consumed to produce the NGLs, less the operating costs of the gas plants. Processing contracts based on this type of arrangement are generally called keepwhole contracts. Specifically, a keepwhole contract is defined as a natural gas processing arrangement where the processor (i.e., the Company) generally takes title to the NGLs extracted from natural gas. The processor reimburses the producer (e.g., Shell or others) for the market value of the energy extracted from the natural gas stream in the form of fuel and NGLs (known as "shrinkage") based on the Btus (a measure of heat value) consumed multiplied by the market value for natural gas. The processor derives a profit margin to the extent the market value of the NGLs extracted exceeds the market value of the fuel and shrinkage and the operating costs of the natural gas plant. The gas processing business does not generally exhibit a high degree of seasonality.

The most significant contract affecting this operating segment is the 20-year Shell Processing Agreement that grants the Company 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 the developments currently referred to as deepwater. Shell is the largest oil and gas producer and holds one of the largest lease positions in the deepwater Gulf of Mexico. Generally, the Shell Processing Agreement grants the Company 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 the Company's gas processing facilities 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.

As noted previously, this segment also includes the results of the Company's merchant activities. Generally, in its isobutane merchant activities the Company takes title to feedstock products and sells processed end products. In the case of its gas processing facilities, the Company takes title to a portion of the mixed NGLs (such amount defined by contract) that it extracts from the natural gas stream. The purity NGL products extracted from the mixed NGL stream are then sold by the Company in the normal course of business. The Company from time to time uses financial instruments to reduce its commodity price exposure. For a general discussion on the Company's commodity risk management policies and exposure, see Item 7A of this Form 10-K, "Quantitative and Qualitative Disclosures about Market Risk."

In its isobutane merchant business, the Company has entered into contracts to sell isobutane. The Company can meet its sales obligations either by:

- purchasing normal butane in the spot market or utilizing normal butane inventory from equity gas plant production and isomerizing it;
- purchasing mixed butane on the spot market, including imports, and processing it through a DIB; or
- purchasing isobutane in the spot markets or utilizing isobutane inventory from equity gas plant production.

When the price differential between normal butane and isobutane is not substantial enough to economically justify isomerization, the Company purchases isobutane or uses its own inventory of isobutane for delivery to its sales customers who pay market-based prices.

The Company utilizes a fleet of approximately 625 railcars in its merchant activities, the majority of which are under short and long-term leases. The railcars are used to deliver feedstocks to Company facilities and transport NGL products throughout the United States. The Company also has 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. The costs of maintaining the railcars and associated assets are a cost of the NGL merchant business.

Octane Enhancement

The Company's Octane Enhancement segment consists of its 33.3% interest in BEF, which owns and operates a facility that produces motor gasoline additives to enhance octane. The BEF facility currently produces MTBE and is located within the Company's Mont Belvieu, Texas complex. The gross capacity of the MTBE facility is approximately 15 MBPD with a net capacity of 5 MBPD. For the years 2000, 1999 and 1998, net production averaged 5 MBPD or near capacity. The other owners of BEF are Sun and Mitchell. EPCO operates the facility under a long-term contract.

MTBE is produced by reacting methanol with isobutylene, which is derived from isobutane. MTBE was originally used as an octane enhancer in motor gasoline, partly in response to the lead phase-down program begun in the mid-1970's. Following implementation of the Clean Air Act Amendments of 1990, MTBE became a widely-used oxygenate to enhance the clean burning properties of motor gasoline. Although oxygen requirements can be obtained by using various oxygenates such as ethanol, ETBE and TAME, 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.

Substantially all of the MTBE produced in the United States is used in the production of oxygenated motor gasoline that is required to be used in carbon monoxide and ozone non-attainment areas designated pursuant to the Clean Air Act Amendments of 1990 and the California oxygenated motor gasoline program. Demand for MTBE is primarily affected by the demand for motor gasoline in these areas. Motor gasoline usage in turn is affected by many factors, including the price of motor gasoline (which is dependent upon crude oil prices) and general economic conditions. Historically, the spot price for MTBE has been at a modest premium to gasoline blend values. Future MTBE demand is highly dependent on environmental regulation, federal legislation and the actions of individual states.

Each of the owners of BEF is responsible for supplying one-third of the facility's isobutane feedstock through June 2004. Sun and Mitchell have each contracted to supply their respective portions of the feedstock from the Company's isomerization facilities. The methanol feedstock is purchased from third parties under long-term contracts and transported to Mont Belvieu by a dedicated pipeline which is part of the Houston Ship Channel Pipeline System. As mentioned previously in the Pipeline segment discussion, management anticipates that BEF's MTBE production will be transported using this same pipeline system beginning in April 2001.

BEF has a ten-year off-take agreement with Sun under which they are required to purchase all of the plant's MTBE production through September 2004. Through May 31, 2000, Sun was required to pay for the MTBE using the following pricing structure:

- for the first 193,450,000 gallons of MTBE produced per contract year, the higher of (i) a contractual floor price or (ii) a toll or spot market-related price (as defined within the agreement); and
- a spot market-related price for all volumes in excess of this amount.

The floor price was a price sufficient to cover essentially all of BEF's operating costs plus principal and interest payments on its bank term loan. In general, Sun paid the floor price during the periods in which it was in effect.

Beginning June 1, 2000 through the remainder of the agreement, the pricing on all MTBE delivered to Sun changed to a market-related negotiated price which generally approximates Gulf Coast MTBE spot prices. The market-related negotiated price is subject to fluctuations in commodity prices for MTBE. MTBE spot prices are generally stronger during the April to September period of each year which corresponds with the summer driving season.

Recent Regulatory Developments. The production of MTBE is driven by oxygenated fuels programs enacted under the federal Clean Air Amendments of 1990 and other legislation. Any changes 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. On March 25, 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. In addition, legislation to amend the federal Clean Air Act has been introduced in the U.S. House of Representatives to ban the use of MTBE as a fuel additive within three years. 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. No assurance can be given as to whether this or similar legislation ultimately will be adopted or whether the U.S. Congress or the EPA might take steps to override the MTBE ban in California.

Alternative Uses of the BEF facility. In light of the regulatory climate, the owners of BEF are formulating a contingency plan for use of the BEF facility if MTBE were banned or significantly curtailed. The owners of BEF are exploring a possible conversion of the BEF facility from MTBE production to alkylate production. One conversion alternative is expected to result in similar operating margin as that currently anticipated from the facility if it were to remain in MTBE service. If this approach were taken, the cost to convert the facility would range from $20 million to $25 million, with the Company's share being $6.7 million to $8.3 million. A second conversion alternative would increase both production capacity and overall margin and cost between $50 million and $90 million, with the Company's share being $16.7 million to $30 million. Management anticipates that if MTBE is banned alkylate demand will rise as producers use it to replace MTBE as an octane enhancer. Greater alkylate production would be expected to increase isobutane consumption nationwide and result in improved isomerization margins for the Company.

Other

This operating segment is primarily comprised of fee-based marketing services. The Company performs NGL marketing services for a small number of clients for which it charges a commission. The clients served are primarily located in the states of California, Illinois and Washington. The Company utilizes the resources of its gas processing merchant business group to perform these services. 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. The Company handles approximately 30,000 barrels per day of various NGL products through its fee-based services with the period of highest activity occurring during the winter months. This segment also includes other engineering services, construction equipment rentals and computer network services that support various plant operations.

Competition

The consumption of NGL products in the United States can be separated among 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 uses, 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, the Company believes any imbalance in the prices of NGLs and NGL products and alternative products would be temporary.

Although competition for NGL fractionation services is based primarily on the fractionation fee, the ability of a NGL fractionator to obtain and distribute product is a function of the existence of the necessary pipeline transportation and storage facilities. A NGL fractionator connected to an extensive transportation and distribution system has direct access to a larger market than its competitors. Overall, the Company believes it provides a broader range of services than any of its competitors. In addition, the Company believes its joint venture relationships enable it to contract for the long-term utilization of a significant amount of its NGL fractionation facilities with major producers and consumers of NGLs or NGL products.

The Company's Mont Belvieu NGL fractionation facility competes for volumes of mixed NGLs with three other NGL fractionators at Mont Belvieu: Cedar Bayou Fractionators, a joint venture between Dynegy and BP (205 MBPD capacity); Gulf Coast Fractionators, a joint venture of Conoco, Mitchell and Dynegy (110 MBPD capacity); and Diamond-Koch, a joint venture between Ultramar Diamond, Koch and Duke Energy (reported to be 160 MBPD capacity). ExxonMobil operates a NGL fractionation facility (110 MBPD capacity) in Hull, Texas that is connected to Mont Belvieu by pipeline and Phillips operates a NGL fractionation facility (100 MBPD capacity) in Sweeny, Texas that is connected to Mont Belvieu by pipeline. ExxonMobil and Phillips use their facilities primarily to process their own NGL production but at certain times these facilities compete with the NGL fractionators at Mont Belvieu.

The Company's NGL fractionation facilities also compete on a more limited basis with two NGL fractionators in Conway, Kansas: Williams (107 MBPD capacity) and Koch (200 MBPD capacity) and with a number of decentralized, smaller NGL fractionation facilities in Louisiana, the most significant of which are Promix at Napoleonville, in which the Company owns a one-third interest (145 MBPD capacity), Texaco/Williams at Paradis (45 MBPD capacity) and EPE at Eunice and Riverside (62 MBPD combined capacity). In recent years, the Conway market has experienced excess capacity and prices for NGL products that are generally lower than prices at Mont Belvieu, although prices in Conway tend to strengthen along with demand for propane in winter months. Finally, a number of producers operate smaller-scale NGL fractionators at individual field processing facilities.

In the isomerization market, the Company competes primarily with Koch at Conway, Kansas; Enron at Riverside, Louisiana; and Conoco at Wingate, New Mexico. Enron and Valero also produce isobutane, primarily for internal production of MTBE. Competitive factors affecting isomerization operations include the market price differential between normal butane and isobutane as well as the fees charged for isomerization services, long-term contracts, the availability of commercial capacity, the ability to produce a higher purity isobutane product and storage and transportation support.

BEF competes with a number of MTBE producers, including a number of refiners who produce MTBE for internal consumption in the manufacture of reformulated motor gasoline. Competitive factors affecting MTBE production include production costs, long-term contracts, the availability of commercial capacity and federal and state environmental regulations relating to the content of motor gasoline.

The Company competes with numerous producers of high purity propylene, which include many of the major refiners on the Gulf Coast. The Company is in direct competition with Diamond-Koch which also has polymer grade propylene production facilities in Mont Belvieu, Texas. Both the Company and Diamond-Koch facilities process refinery grade propylene produced by third party refineries. The Company's ability to attract feedstock is enhanced by its distribution system capabilities which include pipelines, a dock for unloading barges and a tank truck and railcar unloading facility. The Company's facilities use an integrated heat pump system, supplemented by electric drivers. This provides for very efficient operating costs and flexibilities. The Company is able to attract feedstock from a variety of suppliers by providing service to match the suppliers logistic requirements. The Company has entered into long-term sale and processing agreements with key customers and is able to be competitive in price due to its lower operating costs and variable feedstock supply. The Company has developed delivery systems to its key customers which meet or exceed those of its competitors.

Certain of the Company's competitors are major oil and natural gas companies and other large integrated pipeline or energy companies that have greater financial resources than the Company. The Company believes its independence from the major producers of NGLs and petrochemical companies is often an advantage in its dealings with its customers, but the Company's continued success will depend upon its ability to maintain strong relationships with the primary producers of NGLs and consumers of NGL products, particularly in the form of long-term contracts and joint venture relationships.

The United States Gulf Coast gas processing business is competitive. The Company encounters competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each of these companies has varying levels of financial and personnel resources. The principal areas of competition include obtaining the gas plant capacities required to meet the Company's processing needs, obtaining gas supplies where the Company has excess processing capacity and in the marketing of the final NGL products at the tailgate of the Company's fractionation facilities. Overall competition is impacted by supply and demand for both natural gas as a feedstock and finished NGL products. In the Company's fee-based marketing services, the principal methods of competition revolve around price and quality of service.

Employees

At December 31, 2000, EPCO employed 782 employees involved in the management and operation of assets owned and operated by the Company none of whom were members of a union. The Norco facilities are managed by the Company with the assets operated under contract by union employees of Shell. Shell's relationship with its union employees at Norco can be characterized as good and the Company believes that this good relationship will continue.

Major Customers of the Company

The Company's revenues are derived from a wide customer base and no single customer accounted for more than 10% of consolidated revenues in fiscal 2000. For a more complete discussion of significant customers in the last three fiscal years, see Note 15 of the Notes to the Consolidated Financial Statements.

Regulation

Interstate Common Carrier Pipeline Regulation

The Company's Chunchula, Lou-Tex Propylene, Lou-Tex NGL and Lake Charles/Bayport pipelines are interstate common carrier oil pipelines subject to regulation by Federal Energy Regulatory Commission ("FERC") under the October 1, 1977 version of the Interstate Commerce Act ("ICA").

Standards for Terms of Service and Rates. As interstate common carriers, the Chunchula, Lou-Tex Propylene, Lou-Tex NGL and Lake Charles/Bayport pipelines provide service to any shipper who requests transportation services, provided that the products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. The ICA requires the Company to maintain tariffs on file with the FERC that set forth the rates the Company charges for providing transportation services on the interstate common carrier pipelines as well as the rules and regulations governing these services.

The ICA gives the FERC authority to regulate the rates the Company charges 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 collected 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 for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period 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 pipelines 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.

The Company believes the rates it charges for transportation service on its interstate pipelines 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 to the Company's rates as well as the novelty and uncertainty related to the FERC's new indexing methodology, the Company is unable to predict what rates it will be allowed to charge in the future for service on its interstate common carrier pipelines. Furthermore, because rates charged for transportation must be competitive with those charged by other transporters, the rates set forth in the Company's tariffs will be determined based on competitive factors in addition to regulatory considerations.

Allowance for Income Taxes in Cost of Service. In a 1995 decision regarding Lakehead Pipe Line Company ("Lakehead"), FERC ruled that an interstate pipeline owned by a limited partnership could not include in its cost of service an allowance for income taxes with respect to income attributable to limited partnership interests held by individuals. On request in 1996, FERC clarified that, in order to avoid any effect of a "curative allocation" of income from individual partners to the corporate partner, an allowance for income taxes paid by corporate partners must be based on income as reflected on the pipeline's books for earning and distribution rather than as reported for income tax purposes. Subsequent appeals of these rulings were resolved by a 1997 settlement among the parties and were never adjudicated. The effect of this policy on the Company is uncertain. The Company's rates are set using the indexing method and have been grandfathered. It is possible that a party might challenge the Company's grandfathered rates on the basis that the creation of the Company constituted a substantial change in circumstances, potentially lifting the grandfathering protection. Alternatively, a party might contend that, in light of the Lakehead ruling and creation of the Company, the Company's rates are not just and reasonable. While it is not possible to predict the likelihood that such challenges would succeed at FERC, if such challenges were to be raised and succeed, application of the Lakehead ruling would reduce the Company's permissible income tax allowance in any cost of service, and rates, to the extent income is attributable to partnership interests held by individual partners rather than corporations.

Intrastate Common Carrier Regulation

The Sorrento NGL products pipeline, the Yscloskey and Toca-to-Norco petroleum products pipeline, the Norco-to-Sorrento and the Tebone-to-Vulcan, Sorrento, Norco, and Geismar ethane pipelines and the Norco-to-Sorrento propane pipeline are intrastate common carrier pipelines that are subject to various Louisiana state laws and regulations that affect the terms of service and rates for such services. The Company's Houston Ship Channel Pipeline and the remainder of its Louisiana pipelines are intrastate private carriers not subject to rate regulation.

Other State and Local Regulation

The Company's 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.

Cogeneration

The Company cogenerates electricity for internal consumption and heat for a process-related hot oil system at Mont Belvieu. If this electricity were sold to third parties, the Company's 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 the Company 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 by the Company's plant facilities, the Company's cogeneration activities are not subject to public utility regulation under federal or Texas law.

Environmental Matters

General. The operations of the Company are subject to federal, state and local laws and regulations relating to release of pollutants into the environment or otherwise relating to protection of the environment. The Company believes its operations and facilities are in general compliance with applicable environmental regulations.

However, risks of process upsets, accidental releases or spills are associated with the Company's operations and there can be no assurance that significant costs and liabilities will not be incurred, including those relating to claims for damage to property and persons.

The clear 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 instances, criminal penalties or, in rare circumstances, injunctions. The Company believes the cost of compliance with environmental laws and regulations will not have a significant effect on the results of operations or financial position of the Company. 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 costs, the Company may be unable to pass on those increases to its customers. The Company 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.

Solid Waste. The Company currently owns or leases, and has 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 on or under various properties owned by or leased by the Company during the operating history of those facilities. In addition, a small number of these properties may have been operated by third parties over whom the Company 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, the Company could be required to remove or remediate previously disposed wastes or property contamination including groundwater contamination. The Company does not believe that there presently exists significant surface and subsurface contamination of the Company properties by hydrocarbons or other solid wastes.

The Company generates 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 generated by the Company that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements. Such changes in the regulations may result in additional capital expenditures or operating expenses by the Company.

Superfund. 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 the 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 classes of persons the costs they incur. Although "petroleum" is excluded from CERCLA's definition of a "hazardous substance," in the course of its ordinary operations the Company will generate wastes that may fall within the definition of a "hazardous substance." The Company may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed. The Company has not received any notification that it may be potentially responsible for cleanup costs under CERCLA.

Clean Air Act--General. The operations of the Company 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 the operations of the pipelines, processing and storage facilities. For example, the Mont Belvieu processing and storage facility is 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 in the country in this "severe" category. One of the other consequences of this non-attainment status is the potential imposition of lower limits on the emissions of certain pollutants, particularly oxides of nitrogen which are produced through combustion, as in the gas turbines at the Mont Belvieu processing facility. Regulations imposing more strict requirements on existing facilities were issued in December, 2000. These regulations mandate 90% reductions in oxides of nitrogen emissions from point sources such as the gas turbines at the Company's Mont Belvieu processing facility. The technical practicality and economic reasonableness of requiring existing gas turbines to achieve such reductions, as well as the substantive basis for setting the 90% reduction requirements, have been challenged under state law in litigation filed in the District Court of Travis County, Texas, on January 19, 2001, by the Company as part of a coalition of major Houston-Galveston area industries. In addition to the Company, the plaintiffs in this case are the BCCA Appeal Group, Equistar Chemicals, LP, Lyondell Chemical Company, Lyondell-CITGO Refining L.P. and Reliant Energy, Incorporated; named as defendants are the Texas Natural Resource Conservation Commission and its chairman, commissioners and executive director. The suit seeks a ruling that these regulations are invalid and void and asks for a temporary injunction to stay their effectiveness pending final judgment in the case. If these regulations stand as issued, they would require substantial redesign and modification of the Mont Belvieu facilities to achieve the mandated reductions; however, the precise impact of these requirements on the Company's operations cannot be determined until this litigation is resolved. Regardless of the outcome of this litigation, the capital expenditures for making the required modifications would be spread over the years leading up to the compliance deadline, which could be as early as 2005.

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. The Company believes its operations, including its processing facilities, pipelines and storage facilities, are in substantial compliance with applicable air requirements.

Clean Air Act--Fuels. See discussion of Octane Enhancement - Recent Regulatory Developments.

Clean Water Act. 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 promulgated pursuant to these laws require that entities such as the Company that discharge into federal and state waters obtain National Pollutant Discharge Elimination System ("NPDES") and/or state permits authorizing these discharges. The Clean Water Act and analogous state 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. The Company believes it will be able to obtain, or be included under, these Clean Water Act permits and that compliance with the conditions of such permits will not have a material effect on the Company.

Underground Storage Requirements. The Company currently owns and operates underground storage caverns that have been created in naturally occurring salt domes in Texas, Louisiana and Mississippi. These storage caverns are used to store NGLs, NGL products, propane/propylene mix and propylene. 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 by state authorities 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. The Company believes its salt dome storage operations, including the caverns, brine pits and brine disposal wells, are in substantial compliance with applicable statutes.

Safety Regulation

The Company's pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, as amended ("HLPSA"), 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 and requires any entity which owns or operates pipeline facilities to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. The Company believes its pipeline operations are in substantial compliance with applicable HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the HLPSA will not have an impact on the Company's results of operations or financial position.

The workplaces associated with the processing and storage facilities and the pipelines operated by the Company are also subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The Company believes it has operated in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

In general, the Company expects expenditures will increase in the future to comply with likely higher industry and regulatory safety standards such as those described above. Such expenditures cannot be accurately estimated at this time, although the Company does not expect that such expenditures will have a significant effect on the Company.

Title to Properties

Real property held by the Company falls into two basic categories: (a) parcels that it owns in fee, such as the land at the Mont Belvieu complex and Petal fractionation and storage facility, and (b) parcels in which its interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for Company operations. The fee sites upon which the major facilities are located have been owned by the Company or its predecessors in title for many years without any material challenge known to the Company relating to title to the land upon which the assets are located, and the Company believes it has satisfactory title to such fee sites. The Company has no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way or license held by it or to its title to any material lease, easement, right-of-way, permit or lease, and the Company believes it has satisfactory title to all of its material leases, easements, rights-of-way and licenses.

Item 3. Legal Proceedings.

EPCO has indemnified the Company against any litigation pending as of the date of its formation. The Company is sometimes named as a defendant in litigation relating to its normal business operations. Although the Company insures itself 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 the Company against liabilities arising from future legal proceedings as a result of its ordinary business activity. See the discussion of litigation the Company has instituted in connection with air pollution control regulations in the Houston-Galveston area on page 22 of this Form 10-K. Other than this litigation, management is aware of no significant litigation, pending or threatened, that may have a significant adverse effect on the Company's 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 Unitholders during the fourth quarter of 2000.

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 New York Stock Exchange) and the amount of quarterly cash distributions paid per Common and Subordinated Unit.

		Price Range		Cash Distributions			
		High	Low	Per Common Unit	Per Subordinated Unit	Record Date	Payment Date
1999	First Quarter	$ 18.500	$ 14.938	$ 0.450	$ 0.450	Jan. 29, 1999	Feb. 11, 1999
	Second Quarter	$ 18.625	$ 15.063	$ 0.450	$ 0.070	Apr. 30, 1999	May 12, 1999
	Third Quarter	$ 20.688	$ 17.875	$ 0.450	$ 0.370	Jul. 30, 1999	Aug. 11, 1999
	Fourth Quarter	$ 20.375	$ 17.000	$ 0.450	$ 0.450	Oct. 29, 1999	Nov. 10, 1999
2000	First Quarter	$ 20.875	$ 18.250	$ 0.500	$ 0.500	Jan. 31, 2000	Feb. 10, 2000
	Second Quarter	$ 22.750	$ 19.500	$ 0.500	$ 0.500	Apr. 28, 2000	May 10, 2000
	Third Quarter	$ 28.938	$ 22.125	$ 0.525	$ 0.525	Jul. 31, 2000	Aug. 10, 2000
	Fourth Quarter	$ 31.875	$ 23.500	$ 0.525	$ 0.525	Oct. 31, 2000	Nov. 10, 2000
2001	First Quarter (through March 19, 2001)	$ 36.800	$ 26.500	$ 0.550	$ 0.550	Jan. 31, 2001	Feb. 9, 2001

On January 17, 2000, the Company declared an increase in its quarterly cash distribution to $0.50 per Unit. This amount was subsequently raised to $0.525 per Unit on July 17, 2000 and $.550 per Unit on December 7, 2000. The increases are attributable to the growth in cash flow that the Company has achieved through the completion of new projects, improved operating results and accretive acquisitions. Although the payment of such quarterly cash distributions is not guaranteed, the Company currently expects that it will continue to pay comparable cash distributions in the future.

As of March 12, 2001, there were approximately 228 Unitholders of record which includes an estimated 8,500 beneficial owners of the Company's Common Units.

Item 6. Selected Financial Data.

The following table sets forth for the periods and at the dates indicated, selected historical financial data for the Company. The selected historical financial data (except for EBITDA of unconsolidated affiliates) have been derived from the Company's audited financial statements for the periods indicated. The selected historical income statement data for each of the three years in the period ended December 31, 2000 and the selected balance sheet data as of December 31, 2000 and 1999 should be read in conjunction with the audited financial statements for such periods included elsewhere in this report. EBITDA of unconsolidated affiliates has been derived from the financial statements of such entities for the periods indicated. See also "Management's Discussion and Analysis of Financial Condition and Results of Operation." The dollar amounts in the table below, except per Unit data, are in thousands. Certain reclassifications have been made to prior year's financial statements to conform to the current year presentation.

	For the Year Ended December 31,				
	2000	1999	1998	1997	1996
Income Statement Data:					
Revenues from consolidated operations (1)	$ 3,049,020	$ 1,332,979	$ 738,902	$ 1,020,281	$ 999,506
Equity in income of unconsolidated affiliates	24,119	13,477	15,671	15,682	15,756
Total	3,073,139	1,346,456	754,573	1,035,963	1,015,262
Operating costs and expenses (1)	2,801,060	1,201,605	685,884	938,392	907,524
Operating margin	272,079	144,851	68,689	97,571	107,738
Selling, general and administrative expenses (2)	28,345	12,500	18,216	21,891	23,070
Operating income	243,734	132,351	50,473	75,680	84,668
Interest expense	(33,329)	(16,439)	(15,057)	(25,717)	(26,310)
Interest income	3,748	886	772	1,934	2,705
Interest income from unconsolidated affiliates	1,787	1,667	809		
Dividend income from unconsolidated affiliates	7,091	3,435			
Other income (expense), net	(272)	(379)	358	793	364
Income before extraordinary chargeand minority interest	222,759	121,521	37,355	52,690	61,427
Extraordinary charge on early extinguishment of debt			(27,176)		
Income before minority interest	222,759	121,521	10,179	52,690	61,427
Minority interest	(2,253)	(1,226)	(102)	(527)	(614)
Net income	$ 220,506	$ 120,295	$ 10,077	$ 52,163	$ 60,813
Basic net income per Unit (3)	$ 3.25	$ 1.79	$ 0.17	$ 0.94	$ 1.10
Number of Units for basic EPU (in 000s)	67,107.5	66,710.4	60,124.4	54,962.8	54,962.8
Diluted net income per Unit (3)	$ 2.64	$ 1.64	$ 0.17	$ 0.94	$ 1.10
Number of Units for diluted EPU (in 000s)	82,443.6	72,788.5	60,124.4	54,962.8	54,962.8
Dividends declared per Common Unit	$ 2.10	$ 1.85	$ 0.77	N/A	N/A
Balance Sheet Data (at period end):					
Total assets	$ 1,951,521	$ 1,494,952	$ 741,037	$ 697,713	$ 711,151
Long-term debt	404,000	295,000	90,000	230,237	255,617
Combined equity/Partners' equity	935,959	789,465	562,536	311,885	266,021
Other Financial Data:					
Cash flows from operating activities	$ 360,688	$ 177,953	$ (9,442)	$ 65,254	$ 98,585
Cash flows from investing activities	(268,798)	(271,229)	(59,182)	(38,261)	(64,879)
Cash flows from financing activities	(36,711)	74,403	59,503	(26,731)	(24,930)
EBITDA (4)	267,026	147,050	55,472	79,882	87,109
EBITDA of unconsolidated affiliates (5)	35,549	23,425	23,912	24,372	25,012

Notes to Selected Financial Data Table

(1) The increase in 2000 revenues and expenses is primarily due to the impact of the TNGL and MBA acquisitions. The TNGL acquisition was effective August 1, 1999 with the MBA acquisition effective July 1, 1999.
(2) 1998 and 1999 expenses are lower than 1997 amounts due to the adoption of the EPCO agreement. The increase in 2000 expenses over 1999 is primarily due to the additional staff and resources deemed necessary to support the Company's ongoing expansion activities resulting from acquisitions and various capital expenditures.
(3) Basic net income per Unit is computed by dividing the limited partners' 99% interest in Net income (after deducting for any incentive income allocations to the General Partner) by the weighted average of the number of Common and Subordinated Units outstanding. Diluted net income per Unit is computed by dividing the limited partners' 99% interest in Net income (after deducting for any incentive income allocations to the General Partner) by the weighted average of the number of Common, Subordinated, and Special Units outstanding.
(4) EBITDA is defined as net income plus depreciation and amortization and interest expense less equity in income of unconsolidated affiliates. Interest expense (excluding amortization of loan costs) was $29.6 million, $14.9 million and $14.7 million in 2000, 1999 and 1998, respectively. EBITDA should not be considered as an alternative to net income, operating income, cash flow from operations or any other measure of financial performance presented in accordance with generally accepted accounting principals. EBITDA is not intended to represent cash flow and does not represent the measure of cash available for distribution, but provides additional information for evaluating the Company's ability to make the minimum quarterly distribution. Management uses EBITDA to assess the viability of projects and to determine overall rate of returns on alternative investment opportunities. Because EBITDA excludes some, but not all, items that affect net income and this measure may vary among companies, the EBITDA data presented above may not be comparable to similarly titled measures of other companies. EBITDA for 1998 excludes the extraordinary charge of $27.2 million related to the early extinguishment of debt.
(5) Represents the Company's pro rata share of net income plus depreciation and amortization and interest expense of the unconsolidated affiliates.

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 the audited consolidated financial statements and notes thereto of the Company included elsewhere herein as well as the other portions of this report on Form 10-K. In particular, the reader should review "Uncertainty of Forward-Looking Statements and Information" found on page 2 of this report on Form 10-K for information regarding forward-looking statements made in this discussion and certain risks inherent in the Company's business. Other risks involved in the Company's business are discussed under Item 7A "Quantitative and Qualitative Disclosures about Market Risk" beginning on page 43 of this report.

Current Business Environment

During most of 2000, the U.S. NGL industry benefited from a steady demand for NGLs, petroleum liquids and MTBE as a result of the strong U.S. economy and firm international demand. Overall, the Company enjoyed outstanding earnings in 2000 in all of its business segments despite the tighter processing margins encountered late in the fourth quarter. The Company's solid performance in 2000 is the result of an integrated NGL system that allows the Company to extract margins through its access to multiple supplies and markets.

The near term enthusiasm of the U.S. NGL industry was somewhat dampened at the end of last year as the cost of natural gas (which is the most significant variable operating expense of most facilities) soared to all time record levels in the fourth quarter of 2000 and first quarter of 2001. Natural gas prices increased from an average of $2.49/MMBtu in the first quarter of 2000 to $5.22/MMBtu in the fourth quarter of 2000 (with December 2000 being the highest of the year at $5.97/MMBtu). In January 2001, the price of natural gas reached record levels of approximately $10/MMBtu (or $60 per barrel on a crude oil equivalent). Generally, as the cost of natural gas increases, certain facilities may become too expensive to operate and are consequently shutdown temporarily. In the case of a natural gas processing plant, high natural gas prices may result in the cost of fuel and shrinkage exceeding the value of the NGLs extracted leading either to shutdown of the facility or to operate at decreased extraction rates (i.e., to operate in "rejection mode").

Because the Company has an integrated NGL system, the Company's natural gas processing plants continued to operate at high levels during the fourth quarter of 2000 when many of its competitors were in rejection mode or shutdown. In December 2000, the Company maintained an equity NGL production rate of 67 MBPD, or about 90% of the full NGL extraction rate. At the beginning of January 2001, with natural gas prices climbing to near $10/MMBtu, it finally became uneconomic to run the Company's natural gas processing facilities at these high extraction rates. As a result of minimal or no NGL extraction, natural gas volumes downstream of the processing plants became higher in NGL content than allowed by pipeline specifications. The natural gas pipeline operators responded by issuing operational flow orders that threatened to shut-in some of the rich natural gas from the deepwater developments unless the NGL content of these natural gas streams was reduced to lower levels. In order to meet the specifications of the natural gas pipeline operators, the Company and producers negotiated interim reductions in fuel and shrinkage costs to levels that were significantly below the prevailing cost of natural gas. With these interim provisions in place, the Company's gas processing plants increased NGL extraction rates with the objective to lower the NGL content of the natural gas to a level satisfactory to the pipeline operators.

As natural gas prices increased to unprecedented levels in January 2001, refiners switched to burning propane as fuel and sold their natural gas into the spot markets. In late December 2000 and January 2001, petrochemical demand softened as petrochemical companies elected to deplete their NGL raw material inventories and their finished product inventories of ethylene and propylene and optimized their ethylene production from cracking naptha. Management believes that the petrochemical companies can take this position for only a short time and these companies will return to the NGL marketplace to purchase ethane later in the first quarter of 2001 due to their needs for greater ethylene production.

As a result of reduced supplies of NGLs from gas processing facilities and refineries in December 2000 and extending into the first quarter of 2001, U.S. Gulf Coast fractionation and pipeline volumes (including those at the Company's facilities) declined. This situation, however, also created regional shortages of NGLs, especially propane, which resulted in large regional pricing differences. This provided the Company with opportunities to serve these supply-short markets through the sale of inventory by its Processing merchant business.

Management believes that the gas processing business will have a challenging first quarter of 2001. The current processing environment does, however, present opportunities to take advantage of the Company's integrated NGL system. Looking back over the last year, the Company's NGL production has significantly increased over 1999 levels as a result of steadily growing levels of natural gas production available for processing, higher NGL content natural gas and new processing facilities such as the Company's Neptune plant. Neptune commenced operations in February 2000 and added approximately 7 MBPD of equity NGL production for the year. For 2000, equity NGL production averaged 72 MBPD versus 67 MBPD in 1999. Management believes that the Company's equity NGL production volumes will continue to increase in 2001 as a result of gas production from several new Gulf of Mexico gas fields scheduled to come on-line in which the Company holds gas processing rights, the most significant of which is Shell's deepwater Brutus development (with an expected equity NGL production of 10 MBPD by the end of 2001). Management's belief is based in part on the premise that natural gas prices will continue to moderate over the coming months (see First Quarter 2001 natural gas prices in the table on page 30); however, if fuel costs return to the record levels seen in January 2001, equity NGL production rates may actually decline in 2001.

The highly competitive environment in which the Company's Mont Belvieu NGL fractionators operate has continued to suppress NGL fractionation fees at these facilities. The Company has and is continuing to aggressively acquire new and reacquire previous NGL fractionation customers, along with offering competitively-priced bundled service packages involving transportation, fractionation and other services. These service packages allow the Company to take advantage of its presence throughout the entire Gulf Coast NGL value chain. As a result of these efforts, gross processing volumes at the Mont Belvieu NGL fractionation facility increased to 170 MBPD in 2000 from 156 MBPD in 1999. With the completion of the Lou-Tex NGL Pipeline in the fourth quarter of 2000, the Company is positioned to fully utilize its Mont Belvieu NGL fractionation facilities to process NGL's from Louisiana starting in the first quarter of 2001. In January 2001, the Company announced that it had entered into a long-term agreement to exchange NGLs produced at the Sea Robin natural gas processing plant in Vermilion Parish, Louisiana, for finished NGL products at Mont Belvieu using the Lou-Tex NGL Pipeline. Initial gross processing volumes are expected to be 16 MBPD and are forecast to increase to over 20 MBPD by the end of 2001.

The demand for commercial isomerization services depends upon the industry's requirements for (i) isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations and (ii) high purity isobutane. The market for the Company's services was firm throughout most of 2000 due to the continued need for isobutane for alkylation and the production of propylene oxide and MTBE. As part of its commercial isomerization business, the Company produces the high purity isobutane used in the production of MTBE at the BEF facility. Isobutane demand from the BEF facility was temporarily curtailed due to a maintenance outage at the MTBE plant that began in early December 2000. With the startup of the BEF plant in mid-February 2001, management anticipates that the demand for its commercial isomerization services will return to normal levels.

During the third quarter of 2000, the rapid price increase for propylene experienced during the first half of 2000 began to reverse. During the first half, propylene prices were driven by the dramatic increases in crude oil and NGL prices. These factors contributed to similar increases in the cost for ethylene and propylene from steam crackers and for refinery grade propylene produced by refineries. In addition, the price spike in motor gasoline, natural gas and propane created a very competitive market for refinery grade propylene which is used in the production of alkylate (which is blended into motor gasoline), substituted for natural gas as refinery fuel and blended into propane streams for the fuels market. With the perceived stabilization and softening in crude oil and natural gas prices, propylene buyers have been successful in achieving price reductions by reducing purchases and consuming inventory. Contract prices for polymer grade propylene increased from approximately 19.5 cents per pound at the beginning of 2000 to 27.5 cents per pound by the end of June. By the end of December, the contract price had slipped to 23.5 cents per pound. Management anticipates that prices will continue to soften in early 2001 with the price leveling out to that seen at the beginning of 2000. The Company is exposed to these price decreases only to the extent that it sells product pursuant to long-term agreements having market-based pricing or transactions on the spot market (see page 8 for a discussion of propylene merchant business contracts).

During 2000, the favorable domestic economy supported strong demand for the Company's pipeline transportation services as NGL feedstocks and products were consumed at record levels throughout the Gulf Coast region. The Company's pipeline volumes increased significantly to 367 MBPD in 2000 from 264 MBPD in 1999 primarily due to volumes attributable to the assets acquired in the TNGL acquisition, the purchase of the Lou-Tex Propylene Pipeline in March 2000 and the completion of the Lou-Tex NGL Pipeline in November 2000. As noted above, pipeline volumes weakened as NGL production from gas processing facilities decreased in late 2000 and January 2001 in reaction to the high natural gas prices. This trend began to reverse itself in February 2001 as natural gas prices declined and processing volumes at the Company's gas processing facilities increased.

The Company anticipates using the Lou-Tex NGL Pipeline to provide transportation services for NGL products and mixed propane/propylene streams between the Louisiana and Texas markets in addition to transporting NGL production from Louisiana gas processing facilities to Mont Belvieu for fractionation. Management believes that the Company's pipeline system and storage assets in the Louisiana to Mont Belvieu, Texas corridor and its import/export terminal on the Houston Ship Channel provide the Company with the infrastructure for continued success in the NGL marketplace.

During the second quarter of 2000, BEF's MTBE operations (classified under the "Octane Enhancement" business segment) benefited from higher crude oil prices as well as a tight international MTBE supply environment. Due to contractual arrangements, BEF began selling its MTBE at market-related prices in April 2000 at a time when MTBE market prices were increasing significantly due to their indirect link to crude oil prices (which were on the increase), MTBE supply imbalances between Europe and the United States (due to the temporary diversion of Middle East MTBE production to Europe) and domestic gasoline refining demand in anticipation of the normal summer driving season. The combination of these external factors resulted in the market price for MTBE increasing to near record levels in the second quarter of 2000 peaking at an average $1.58 per gallon in June. During the third quarter, MTBE market prices deflated rapidly as imports returned to the domestic market and as gasoline refiners trimmed oxygenate usage (due to the end of the summer driving season) and depleted MTBE inventories in anticipation of falling crude oil prices. By October 2000, MTBE prices had hit a low of $0.98 per gallon.

As MTBE prices weakened during the latter half of 2000, feedstock costs began to increase (primarily due to the rise in natural gas prices mentioned previously) resulting in negative operating margins. In order to reduce its exposure to negative margins, BEF management elected to reschedule routine annual maintenance activities that had been originally planned for the spring of 2001 to be performed during December 2000 and January 2001. The facility restarted operations in mid-February 2001 with the return of positive operating margins. Management anticipates that MTBE prices will strengthen in the next few months as refiners begin purchasing MTBE in preparation of 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 (a)	Crude Oil, $/barrel (b)	Ethane, $/gallon (a)	Propane, $/gallon (a)	Normal Butane, $/gallon (a)	Isobutane, $/gallon (a)	Polymer Grade Propylene, $/pound (a)
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 (c)	$8.02	$29.66	$0.44	$0.57	$0.67	$0.71	$0.23

(a) Natural gas, NGL and polymer grade propylene prices represent an average of index prices
(b) Crude Oil price is representative of West Texas Intermediate
(c) Natural gas prices averaged $9.87 per MMBtu during January and moderated to $6.17 per MMBtu during February. The first quarter 2001 prices reflect January and February only.

Results of Operation of the Company

The Company has five reportable operating segments: Fractionation, Pipeline, Processing, Octane Enhancement and Other. Fractionation includes NGL fractionation, butane isomerization (converting normal butane into high purity isobutane) and polymer grade propylene fractionation services. Pipeline consists of pipeline, storage and import/export terminal services. Processing includes the natural gas processing business and its related NGL merchant activities. Octane Enhancement represents the Company's 33.3% ownership interest in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and other plant support functions.

The management of the Company evaluates segment performance on the basis of gross operating margin ("gross operating margin" or "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 selling, 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. The Company's equity earnings from unconsolidated affiliates are included in segment gross operating margin.

The Company's gross operating margin by segment (in thousands of dollars) along with a reconciliation to consolidated operating income over the past three years were as follows:

	For the Year Ended December 31,		
	2000	1999	1998
Gross Operating Margin by segment:			
Fractionation	$ 129,376	$ 110,424	$ 66,627
Pipeline	56,099	31,195	27,334
Processing	122,240	28,485	(652)
Octane enhancement	10,407	8,183	9,801
Other	2,493	908	(3,483)
Gross Operating Margin total	320,615	179,195	99,627
Depreciation and amortization	35,621	23,664	18,579
Retained lease expense, net	10,645	10,557	12,635
Loss (gain) on sale of assets	2,270	123	(276)
Selling, general and administrative expenses	28,345	12,500	18,216
Consolidated operating income	$ 243,734	$ 132,351	$ 50,473

Certain 1999 amounts have been reclassified to conform with the 2000 presentation.

The Company's significant plant production and other volumetric data (in thousands of barrels per day on a net basis) for the last three years were as follows:

	For the Year Ended December 31,		
	2000	1999	1998
Plant production data:			
NGL Production	72	67	n/a
NGL Fractionation	213	184	73
Isomerization	74	74	67
Propylene Fractionation	33	28	26
MTBE	5	5	5
Major Pipelines	367	264	200

In order to more accurately compare operating rates between the 2000 and 1999 periods, the 1999 volumes associated with the assets acquired from TNGL have been adjusted to reflect the period in which the Company owned them.

Recent Acquisitions

1999 Acquisitions. The Company completed two acquisitions during the third quarter of 1999. Effective August 1, 1999, the Company acquired TNGL from Shell, in exchange for 14.5 million non-distribution bearing, convertible special partnership Units of the Company and $166 million in cash. The Company also agreed to issue up to 6.0 million additional non-distribution bearing special partnership Units to Shell in the future if the volumes of natural gas that the Company processes for Shell reach agreed upon levels in 2000 and 2001. The first 3.0 million of these additional special partnership Units were issued on August 1, 2000.

The TNGL businesses acquired include natural gas processing and NGL fractionation, transportation and storage in Louisiana and Mississippi and its NGL supply and merchant business. TNGL has varying interests in eleven natural gas processing plants, four NGL fractionation facilities, four NGL storage facilities, approximately 1,500 miles of pipelines and is party to the Shell Processing Agreement, a 20 year natural gas processing agreement.

The Company accounted for this acquisition using the purchase method. The purchase price allocation for the 20-year natural gas processing agreement (classified as an Intangible Asset on the balance sheet) was a net $84.6 million and $52.9 million at December 31, 2000 and 1999, respectively. During 2000, the asset's recorded value was increased to reflect the 3.0 million additional special partnership Units issued to Shell on August 1, 2000, purchase accounting adjustments and related amortization.

Effective July 1, 1999, the Company acquired an additional 25% interest in the Mont Belvieu NGL fractionation facility from Kinder Morgan for a purchase price of $41.2 million in cash and the assumption of $4 million in debt. An additional 0.5% interest in the same facility was purchased from EPCO for $0.9 million in cash. This acquisition (referred to as the "MBA acquisition") increased the Company's effective interest in the Mont Belvieu NGL fractionation facility from 37.0% to 62.5%. As a result of this acquisition, the results of operations after July 1, 1999 were consolidated rather than included in equity income from unconsolidated affiliates.

The results of operations for the year ended December 31, 1999 include five month's impact of the TNGL businesses acquired from Shell and six month's impact of the additional ownership interest in the Mont Belvieu NGL fractionation facility acquired from Kinder Morgan and EPCO. See Note 2 to the Consolidated Financial Statements for selected pro forma financial data reflecting these transactions as if they had occurred on January 1, 1999 and 1998.

2001 Acquisitions. The Company has recently announced and/or completed the acquisition of three Louisiana-based natural gas pipeline systems:

- Acadian Gas, LLC ("Acadian");
- Stingray Pipeline Company, LLC ("Stingray") and West Cameron Dehydration, LLC ("West Cameron"); and
- Sailfish Pipeline Company, LLC ("Sailfish") and Moray Pipeline Company, LLC ("Moray").

The acquisition of these natural gas pipeline systems represents a strategic investment for the Company and allows for entry into the natural gas gathering, transportation, marketing and storage business. Management believes 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 the Company's midstream energy service relationship with long-term NGL customers (producers, petrochemical suppliers and refineries) and offer additional fee-based cash flows and opportunities for enhanced services to customers.

Acadian. On September 25, 2000, the Company announced that it had executed a definitive agreement to purchase Acadian from Coral Energy, an affiliate of Shell, for $226 million in cash, inclusive of working capital. The acquisition of Acadian integrates its natural gas pipeline systems in South Louisiana with the Company's Gulf Coast natural gas processing and NGL fractionation, pipeline and storage system. The Acadian acquisition gives the Company an extensive intrastate natural gas pipeline system with access to both supply and markets; positions the Company to compete for incremental natural gas supplies from new discoveries onshore, the offshore Louisiana continental shelf and Gulf of Mexico deepwater developments; enables the Company to take advantage of growing industrial and petrochemical demand (including new gas-fired power generation projects) along with additional natural gas processing opportunities.

Acadian's assets are comprised of the 438-mile Acadian, 577-mile Cypress and 27-mile Evangeline natural gas pipeline systems, which together have over one billion cubic feet ("Bcf") per day of capacity. These natural gas pipeline systems are wholly-owned by Acadian with the exception of the Evangeline system in which Acadian holds an approximate 49.5% economic interest. The system includes a leased natural gas storage facility at Napoleonville, Louisiana. Completion of this transaction is subject to certain conditions, including regulatory approvals. The purchase is expected to be completed during the first quarter of 2001.

Stingray, West Cameron, Sailfish and Moray (collectively, the "El Paso acquisition"). On January 29, 2001, the Company announced that it had completed the purchase of 50% of the membership interests of Stingray and West Cameron, together with some offshore lateral pipelines for approximately $25.1 million in cash from affiliates of El Paso Energy Partners L.P. ("EPE") and Coastal Corp. Shell purchased the remaining 50% membership interests of both Stingray and West Cameron for an equal amount of cash. In addition, the Company purchased from EPE 100% of the membership interests of Sailfish and Moray for approximately $88.1 million in cash.

Collectively, the Company acquired interests in five natural gas gathering and transmission pipeline systems in the Gulf of Mexico totaling approximately 737 miles of pipeline with an aggregate gross capacity of 2.85 Bcfd. These pipelines and their associated assets are strategically located to serve continental shelf and deepwater developments in the central Gulf of Mexico. As with the Acadian acquisition, the El Paso acquisition broadens the Company's midstream business by providing additional services to customers, and it benefits from increased natural gas production from deepwater Gulf of Mexico development. Management believes that the assets acquired from EPE complement and integrate well with those of the Acadian acquisition.

Stingray owns a 375-mile FERC-regulated two phase natural gas pipeline system that transports natural gas and injected condensate from the High Island, West Cameron, East Cameron, Vermillion and Garden Banks areas in the Gulf of Mexico to onshore transmission systems at Holly Beach and Cameron Parish, Louisiana. West Cameron is an unregulated dehydration facility located at and connected to the onshore terminal of Stingray. Shell is the operator of the Stingray and West Cameron facilities.

Sailfish owns a 25.67% interest in Manta Ray Offshore Gathering Company, L.L.C. ("Manta Ray") and Nautilus Pipeline Company, L.L.C. ("Nautilus"). Moray owns a 33.92% interest in the Nemo Gathering Company, L.L.C. ("Nemo"). Manta Ray (which is jointly owned by Sailfish, Shell and Marathon Gas Transmission Company Inc.) owns 237 miles of unregulated natural gas transmission lines primarily located on the outer continental shelf offshore Louisiana. Nautilus (which is owned by Sailfish, Shell and Marathon Gas Transmission Company Inc.) owns 101 miles of FERC-regulated natural gas pipelines and related facilities extending from points offshore Louisiana to interconnecting pipelines near the Garden City and Neptune gas processing facilities. Nemo (which is jointly owned by Moray and Shell) is a development stage enterprise that is constructing and will operate an offshore Louisiana natural gas gathering pipeline and related facilities that will connect certain Shell offshore platform assets to Manta Ray. Management believes that these assets have a significant upside potential, since Shell and Marathon have dedicated production from over 1,000 square miles of offshore natural gas leases to these systems and only a small portion of this total has been developed to date. Shell is the operator of the Manta Ray, Nautilus and Nemo systems.

Equistar storage facility. In addition to the natural gas pipeline acquisitions, the Company announced on February 1, 2001 that it had acquired a NGL storage facility from Equistar Chemicals, LP for approximately $3.4 million. The salt dome storage cavern, which is located near the Company's Mont Belvieu, Texas complex, has a capacity of one million barrels. The purchase also includes adjacent acreage which would support the development of additional storage capacity.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Revenues, Costs and Expenses and Operating Income. The Company's revenues increased 128% to $3,073.1 million in 2000 compared to $1,346.5 million in 1999. The Company's operating costs and expenses increased by 133% to $2,801.1 million in 2000 versus $1,201.6 million in 1999. Operating income increased 84% to $243.7 million in 2000 from $132.3 million in 1999. The principal factors behind the increase in operating income were (a) the improvement in NGL product prices in 2000 versus 1999 and (b) the additional margins associated with the businesses acquired in the TNGL acquisition. The 1999 period includes five months of margins associated with the TNGL operations whereas the 2000 period includes twelve months.

Fractionation. The Company's gross operating margin for the Fractionation segment increased to $129.4 million in 2000 from $110.4 million in 1999. During 2000, NGL fractionation margin increased $29.7 million over 1999 as a result of additional margins from the four NGL fractionators acquired from Shell in the TNGL acquisition (Promix, Tebone, Venice and Norco NGL fractionators). As noted previously, the 1999 period includes only five months of margin from these fractionators whereas the 2000 period includes twelve months. In addition, equity income from BRF reflects twelve months of operations in 2000 versus six months in 1999. BRF commenced operations in July 1999. Net NGL fractionation volumes increased from 184 MBPD in 1999 to 213 MBPD in 2000 primarily due to the Company's acquisition of new and previous customers at its Mont Belvieu NGL fractionator in 2000 and the increased ownership of the Mont Belvieu NGL fractionator as a result of the MBA acquisition. For 2000, gross operating margin from the isomerization business decreased $7.8 million compared to 1999 primarily due to higher fuel and other operating costs and charges related to the refurbishment of an isomerization unit. Isomerization volumes were 74 MBPD in both 1999 and 2000 due to strong demand for the Company's services. Gross operating margin from propylene fractionation decreased $1.4 million for 2000 compared to 1999 primarily due to higher energy costs. Net volumes at these facilities improved to 33 MBPD in 2000 versus 28 MBPD in 1999 due to the startup of the BRPC propylene concentrator in July 2000.

Pipeline. The Company's gross operating margin for the Pipeline segment was $56.1 million in 2000 compared to $31.2 million in 1999. Overall 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 Houston Ship Channel Distribution 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 Concha Chemical Pipeline Company, an affiliate of Shell, was completed at a cost of approximately $100 million. The effective date of the transaction was March 1, 2000. The Lou-Tex Propylene Pipeline is a 263-mile, 10" pipeline that transports chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. Also acquired in this transaction was a 27.5-mile 6" ethane pipeline between Sorrento and Norco, Louisiana and a 0.5 million barrel storage cavern at Sorrento, Louisiana.

The Lou-Tex NGL Pipeline System consists of a recently completed 206-mile NGL pipeline used (i) to provide transportation services for NGL products and refinery grade propylene between the Louisiana and Texas markets and (ii) to transport mixed NGLs from the Company's Louisiana gas processing facilities to the Mont Belvieu NGL fractionation facility. Construction of this system was completed during the fourth quarter of 2000 at a cost of approximately $87.9 million.

Processing. The Company's gross operating margin for Processing was $122.2 million in 2000 compared to $28.5 million in 1999. Due to the TNGL acquisition, the 1999 margin includes only five months of gas processing operations whereas the 2000 period includes twelve 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. The Company's gross operating margin for Octane Enhancement increased to $10.4 million in 2000 from $8.2 million in 1999. This segment consists entirely of the Company's equity earnings from its 33.3% investment in BEF, a joint venture facility that currently produces MTBE. The 1999 results include the impact of the Company's $1.5 million pro rata share of a non-cash write-off of BEF's unamortized balance of deferred start-up costs. The 2000 results reflect the impact of higher than normal MTBE market prices during the second quarter and early third quarter and lower debt service costs. BEF made its final note payment in May 2000 and now owns the MTBE facility debt-free.

The MTBE facility was temporarily shutdown in early December 2000 for maintenance. The facility restarted operations in mid-February 2001. MTBE production, on a net basis, was 5 MBPD in both 1999 and 2000.

Other. The Company's gross operating margin for the 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. Apart from this portion of the segment's operations, the gross margin contribution of the other aspects of this segment were insignificant in both 2000 and 1999.

Selling, general and administrative expenses ("SG&A"). SG&A expenses increased to $28.3 million in 2000 from $12.5 million during 1999. The higher costs result from an increase in the administrative services fee charged by EPCO to an average $1.2 million per month in 2000 versus the approximately $1.0 million per month charged in 1999. The remainder of the increase is attributable to the additional staff and resources deemed necessary to support the Company's ongoing expansion activities resulting from acquisitions and other business development.

Interest expense. The Company's interest expense increased to $33.3 million in 2000 from $16.4 million in 1999. The increase is primarily attributable to a rise in average debt levels to $408 million in 2000 from $213 million in 1999. Debt levels have increased over the last year primarily due to capital expenditures for assets such as the Lou-Tex Propylene Pipeline and Lou-Tex NGL Pipeline.

Loss on sale of assets. During the second quarter of 2000, the Company recognized a one-time $2.3 million non-cash charge on the sale of its Longview Terminal to Huntsman Corporation. The Longview Terminal was part of the Pipelines segment and was used to unload polymer grade propylene from NGL tank trucks.

Dividend income from unconsolidated affiliates. The Company received $7.1 million in cash distributions from its cost method investment in VESCO during 2000. During 1999, the Company recorded dividend income from Dixie and VESCO in the amounts of $0.8 million and $2.6 million, respectively. In October 2000, the Company purchased an additional interest in Dixie resulting in a retroactive change in accounting for this investment from the cost method to the equity method (see Note 4 of the Notes to the Consolidated Financial Statements for a description of the Dixie investment).

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Revenues, Costs and Expenses and Operating Income. The Company's revenues increased 78% to $1,346.5 million in 1999 compared to $754.6 million in 1998. The Company's operating costs and expenses increased by 75% to $1,201.6 million in 1999 versus $685.9 million in 1998. Operating income increased 162% to $132.3 million in 1999 from $50.5 million in 1998. The principal factor behind the $81.8 increase in operating income was the TNGL acquisition. Earnings attributable to these assets from the date of acquisition, August 1, 1999, through December 31, 1999 added approximately $48.4 million in gross operating margin to the Company's financial performance. The other primary source of the increase was an overall improvement in NGL product prices in 1999 compared to 1998 levels.

Fractionation. The Company's gross operating margin for the Fractionation segment increased to $110.4 million in 1999 from $66.7 million in 1998. NGL fractionation margin increased $13.7 million over 1998 as a result of additional margins from the four TNGL fractionators. As noted previously, the 1999 period includes five months of margin from these NGL fractionators whereas the 1998 period includes none. In addition, the 1999 period reflects six months of increased ownership of the Mont Belvieu NGL fractionation facility resulting from the MBA acquisition and six months of equity income from BRF which commenced operations in July 1999. Net NGL fractionation volumes increased from 73 MBPD in 1998 to 184 MBPD primarily due to the TNGL fractionators and increased ownership of the Mont Belvieu NGL fractionator. During 1999, gross operating margin from isomerization increased $19.6 million compared to 1998 levels due to exceptional pricing conditions in the first half of 1999 and higher overall production. Isomerization volumes increased from 67 MBPD in 1998 to 74 MBPD in 1999. Gross operating margin from propylene fractionation increased $11.2 million over 1998 levels generally due to increases in polymer grade propylene prices and higher production rates. Volumes at these facilities improved to 28 MBPD in 1999 versus 26 MBPD in 1998.

Pipeline. The Company's 1999 gross operating margin for the Pipeline segment increased $3.9 million compared to 1998. Overall volumes increased to 264 MBPD in 1999 from 200 MBPD in 1998. Of the increase in both margin and volumes, $4.7 million in margin and approximately 56 MBPD in throughput volumes are attributable to the TNGL pipeline and related assets. In addition, equity income from EPIK increased $0.4 million due to increased export volumes. Margins from the Company's Houston Ship Channel import terminal and pipeline distribution system decreased $2.0 million in 1999 primarily due to lower import volumes.

Processing. The Company's 1999 gross operating margin for Processing increased $29.1 million over 1998 results. The increase is primarily due to the gas processing operations acquired from TNGL effective August 1, 1999. The gas processing operations benefited from a favorable NGL pricing environment during the fourth quarter of 1999 and 67 MBPD of equity NGL production.

Octane Enhancement. The Company's 1999 gross operating margin for Octane Enhancement decreased $1.6 million from 1998 levels. The decrease is attributable to a $4.5 million non-cash charge by BEF in January 1999 of which the Company's share was $1.5 million. MTBE net production volumes averaged 5 MBPD in both 1999 and 1998.

Other. The Company's 1999 gross operating margin for the Other segment increased $4.4 over 1998 levels. The increase is attributable to the fee-based marketing business acquired from TNGL. Apart from this portion of the segment's operations, the gross margin contribution of the other aspects of this segment were insignificant in both 1999 and 1998.

Selling, general and administrative expenses ("SG&A"). 1999 SG&A expenses decreased by $5.7 million compared to 1998. The 1999 expenses were lower due to the fixed administrative fees charged to the Company under the EPCO Agreement. The fixed administrative service fees partially reimburse EPCO for the cost of providing certain management and administrative support for the Company. During 1999, these fixed fees ranged from $1.0 million to $1.1 million per month. The Audit and Conflicts Committee of the General Partner is responsible for reviewing and approving any increases in the standard administrative fees chargeable by EPCO to the Company. For additional information regarding the EPCO Agreement, see page 52 of this Form 10-K.

Interest expense. The Company's 1999 interest expense increased $1.3 over 1998 primarily due to the amortization of loan origination costs. Average debt levels in 1999 were generally consistent with those of 1998.

Dividend income from unconsolidated affiliates. As a result of the TNGL acquisition, the Company owned cost method investments in Dixie and VESCO. As such, the Company recorded dividend income from these investments as cash dividends were received. During 1999, the Company recorded dividend income from Dixie and VESCO in the amounts of $0.8 million and $2.6 million, respectively.

Extraordinary charge on early extinguishment of debt. The Company incurred a $27.2 million extraordinary loss during the third quarter of 1998 in connection with the early extinguishment of debt assumed from EPCO in connection with the Company's initial public offering. The extraordinary loss was equal to the remaining unamortized debt origination costs associated with such debt and make-whole premiums payable in connection with the repayment of such debt.

Liquidity and Capital Resources

General

The Company's primary cash requirements, in addition to normal operating expenses, are for capital expenditures (both maintenance and expansion-related), business acquisitions, distributions to the partners and debt service. The Company expects to fund its short-term needs for such items as maintenance capital expenditures and quarterly distributions to the partners from operating cash flows. Capital expenditures for long-term needs resulting from future expansion 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. The Company's debt service requirements are expected to be funded by operating cash flows or refinancing arrangements.

As noted above, certain of the Company's 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, 2000, availability under the Company's bank credit facilities was $400 million (which may be increased to $500 million under certain conditions). In addition to the existing bank credit facilities, the Company issued $450 million of public debt in January 2001 using the remaining shelf availability under its $800 million December 1999 universal shelf registration (the "December 1999 Registration Statement"). The proceeds from this offering were or will be used to acquire the Acadian and EPE natural gas pipeline systems for $339.2 million and to finance the cost to construct certain NGL pipelines and related projects and for working capital and other general partnership purposes. $350 million of shelf availability under the December 1999 Registration Statement was used in March 2000 with the issuance of the $350 Million Senior Notes.

On February 23, 2001, the Company filed a $500 million universal shelf registration (the "February 2001 Registration Statement") covering the issuance of an unspecified amount of equity or debt securities or a combination thereof. For a broader discussion of the Company's outstanding debt and changes therein, see the section below labeled "Long-term Debt".

In June 2000, the Company received approval from its Unitholders to increase by 25,000,000 the number of Common Units available (and unreserved) to the Company for general partnership purposes during the Subordination Period. This increase has improved the future financial flexibility of the Company in any potential business acquisition (see "Amendment to Partnership Agreement" below for further details).

If deemed necessary, management believes that additional financing arrangements can be obtained at reasonable terms. Management believes that maintenance of the Company's investment grade credit ratings (currently, Baa3 by Moody's Investor Service and BBB by Standard and Poors) combined with a continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate its businesses efficiently are a solid foundation to providing the Company with ample resources to meet its long and short-term liquidity and capital resource requirements.

Operating, Investing and Financing Cash Flows for Years Ended December 31, 2000 and 1999

Cash flows from operating activities were a $360.7 million inflow in 2000 compared to a $178.0 million inflow in 1999. Cash flows from operating activities primarily reflect the effects of net income, depreciation and amortization, extraordinary items, equity income and distributions from unconsolidated affiliates and changes in working capital. Net income increased significantly in 2000 over 1999 due to reasons mentioned previously under "Results of Operation of the Company." Depreciation and amortization expense increased a combined $15.7 million in 2000 over 1999 primarily the result of additional capital expenditures and acquisitions. Of the $15.7 million increase, $4.9 million is attributable to increases in amortization expense associated with the 20-year Shell natural gas processing agreement, excess cost related to past acquisitions and loan origination and bond issue costs. The Company received $37.3 million in distributions from its equity method investments in 2000 compared to $6.0 million in 1999. Of the $31.3 million increase in distributions, $10.0 million was from BEF and $8.1 million from EPIK. Distributions from BEF improved period to period due to the strong MTBE prices and margins during the second quarter of 2000. EPIK's distributions increased as a result of higher export activity during 2000. In addition, 2000 included $7.0 million in cash receipts from Promix which was acquired as a result of the TNGL acquisition. The net effect of changes in operating accounts from year to year is generally the result of timing of NGL sales and purchases near the end of the period.

Cash used for investing activities was $268.8 million in 2000 compared to $271.2 million in 1999. Cash outflows included capital expenditures of $243.9 million in 2000 versus $21.2 million in 1999. Capital expenditures in 2000 include $99.5 million for the purchase of the Lou-Tex Propylene Pipeline and related assets and $83.7 million in construction costs for the Lou-Tex NGL Pipeline. In addition, capital expenditures include maintenance capital project costs of $3.5 million in 2000 and $2.4 million in 1999. The 1999 period reflects $208.1 million in net cash payments resulting from the TNGL and MBA acquisitions. In 2000, the Company received $6.5 million in payments from its participation in the BEF note that was purchased during 1998 with the proceeds from the Company's IPO. BEF made its final note payment in May 2000. With BEF's final payment, the Company's receivable relating to its participation in the BEF note was extinguished.

Investing cash outflows in 2000 include $31.5 million in advances to and investments in unconsolidated affiliates compared to $61.9 million in 1999. The decrease is primarily due to the completion of the BRF facility and the Tri-States and Wilprise pipeline systems in 1999. On March 8, 2000, the Company's offer of February 23, 2000 to buy the remaining 88.5% ownership interests in Dixie from the other seven owners expired, with no interest being purchased. In October 2000, the Company announced that a wholly-owned subsidiary had purchased an additional 3,521 shares of common stock of Dixie from Conoco Pipe Line Company for approximately $19.4 million. The purchase increased the Company's economic interest in Dixie to approximately 19.9%.

Cash flows from financing activities were a $36.7 million outflow in 2000 compared to a $74.4 million inflow for 1999. Cash flows from financing activities are primarily affected by repayments of debt, borrowings under debt agreements and distributions to partners. 2000 includes proceeds from the $350 Million Senior Notes and the $54 Million MBFC Loan and the associated repayments on the $200 Million Bank Credit Facility and $350 Million Bank Credit Facility. For a complete discussion of the $350 Million Senior Notes and the $54 Million MBFC Loan and the use of proceeds thereof, see the section labeled "Long-term Debt" below. Financing activities in 1999 include the borrowings associated with the TNGL and MBA acquisitions and outflows of $4.7 million related to the purchase of the Company's Common Units by a consolidated trust. Debt issuance costs increased $0.9 million in 2000 due to the issuance of the $350 Million Senior Notes and the $54 Million MBFC Loan. Distributions to partners and the minority interest increased to $139.6 million in 2000 from $111.8 million in 1999 primarily due to an increase in the quarterly distribution rate (see page 25 of this Form 10-K for a history of the quarterly distribution rates since the first quarter of 1999).

In July 2000, the Company announced a 1,000,000 Unit buy-back program of its publicly-owned Common Units to be executed over a two-year period. Management's intent is to opportunistically acquire Common Units during periods of temporary market weakness at price levels that would be accretive to the Company's remaining Unitholders. The repurchase program will be balanced with plans to grow the Company through investments in internally developed projects and acquisitions, while maintaining an investment grade debt rating. The redemption program will be funded by increased cash distributions from the Operating Partnership from operating cash flows and borrowings under its bank credit facilities. During 2000, 28,400 Common Units were repurchased and retired under this buy-back program at a cost of approximately $0.8 million.

The Company is exposed to various market risks including interest rate and commodity price risk through its gas processing and related NGL businesses. These risks may entail significant cash outlays in the future that are not offset by their underlying hedged positions. For a complete description of the Company's risk management policies and potential exposures, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk" on page 43 of this Form 10-K report.

Future Capital Expenditures

The Company estimates that its share of currently approved capital expenditures in the projects of its unconsolidated affiliates will be approximately $3.1 million during 2001. In addition, the Company forecasts that $128.8 million will be spent during 2001 on currently approved capital projects that will be recorded as property, plant and equipment (the majority of which relate to various pipeline projects).

As of December 31, 2000, the Company had $10.9 million in outstanding purchase commitments attributable to its capital projects. Of this amount, $10.1 million is related to the construction of assets that will be recorded as property, plant and equipment and $0.8 million is associated with capital projects which will be recorded as additional investments in unconsolidated affiliates.

New Texas environmental regulations may necessitate extensive redesign and modification of the Company's Mont Belvieu facilities to achieve the air emissions reductions needed for federal Clean Air Act compliance in the Houston-Galveston area. Until litigation challenging these regulations is resolved, the technology to be employed and the cost for modifying the facilities to achieve enough reductions cannot be determined, and capital funds have not been budgeted for such work. Regardless of the outcome of this litigation, expenditures for emissions reduction projects will be spread over several years, and management believes the Company will have adequate liquidity and capital resources to undertake them. For additional information about this litigation, see the discussion under the topic Clean Air Act--General on page 22 of this Form 10-K.

Long-term Debt

Long-term debt consisted of the following at:

	December 31,	
	2000	1999
Borrowings under:		
$200 Million Bank Credit Facility (1)		$ 129,000
$350 Million Bank Credit Facility (1)		166,000
$350 Million Senior Notes (2)	$ 350,000	
$54 Million MBFC Loan (3)	54,000	
Total	404,000	295,000
Less current maturities of long-term debt		129,000
Long-term debt (4)	$ 404,000	$ 166,000

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(1) Revolving credit facility closed as of December 31, 2000
(2) 8.25% fixed-rate, due March 2005
(3) 8.70% fixed-rate, due March 2010
(4) 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, 2000. See below for a complete description of these new facilities

On January 24, 2001, the Company 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 "$450 Million Senior Notes"). The Company received proceeds, net of underwriting discounts and commissions, of approximately $446.8 million. As noted earlier, the proceeds from this offering were or will be used to acquire the Acadian and EPE natural gas pipeline systems for $339.2 million and to finance the cost to construct certain NGL pipelines and related projects and for working capital and other general partnership purposes.

The Company expects to use the net proceeds from any sale of securities under the February 2001 Registration Statement 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 the Company's funding requirements and the availability of alternative funding sources. The Company routinely reviews acquisition opportunities.

At December 31, 2000, the Company had a total of $50 million of standby letters of credit available under its $250 Million Multi-Year Credit Facility (described below) of which none were outstanding.

$200 Million Bank Credit Facility. On July 27, 1998, the Company entered into a $200 million bank credit facility that included a $50 million working capital facility and a $150 million revolving credit facility. On March 15, 2000, the Company used $169 million of the proceeds from the issuance of the $350 Million Senior Notes to retire this credit facility in accordance with its agreement with the banks.

$350 Million Bank Credit Facility. On July 28, 1999, the Company entered into a $350 Million Bank Credit Facility that included a $50 million working capital facility, a $300 million revolving credit facility and a sublimit of $40 million for letters of credit. On November 17, 2000, this facility was retired using funds available under the Company's new $150 Million 364-Day Credit Facility (described below) in accordance with its agreement with the banks.

$350 Million Senior Notes. On March 13, 2000, the Company 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 Company received proceeds, net of underwriting discounts and commissions, of approximately $347.7 million. The proceeds were used to pay the entire $169 million outstanding principal balance on the $200 Million Bank Credit Facility and $179 million of the then $226 million outstanding principal balance on the $350 Million Bank Credit Facility.

The $350 Million Senior Notes 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 the ability of the Company, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. The Company was in compliance with the restrictive covenants at December 31, 2000.

The issuance of the $350 Million Senior Notes was a takedown under the December 1999 Registration Statement; therefore, the amount of securities available was reduced to $450 million. The remaining amount available under the December 1999 Registration Statement was used to issue the $450 Million Senior Notes in January 2001.

$54 Million MBFC Loan. On March 27, 2000, the Company executed a $54 million loan agreement with the MBFC which was funded with proceeds from the sale of Taxable Industrial Revenue Bonds ("Bonds") by the MBFC. The Bonds issued by the MBFC are 10-year bonds with a maturity date of March 1, 2010 and bear a fixed-rate interest coupon of 8.70%. The Company received proceeds from the sale of the Bonds, net of underwriting discounts and commissions, of approximately $53.6 million. The proceeds were used to pay the then $47 million outstanding principal balance on the $350 Million Bank Credit Facility and for working capital and other general partnership purposes. In general, the proceeds of the Bonds were used to reimburse the Company for costs incurred in acquiring and constructing the Pascagoula, Mississippi natural gas processing plant.

The Bonds were issued at par and are subject to a make-whole redemption right by the Company. The Bonds are guaranteed by the MLP through an unsecured and unsubordinated guarantee. The loan agreement contains certain covenants including maintaining appropriate levels of insurance on the Pascagoula natural gas processing facility and restrictions regarding mergers. The Company was in compliance with the restrictive covenants at December 31, 2000.

$250 Million Multi-Year Credit Facility. On November 17, 2000, the Company entered into a $250 million five-year revolving credit facility that includes a sublimit of $50 million for letters of credit. The November 17, 2005 maturity date may be extended for one year at the Company's option with the consent of the lenders, subject to the extension provisions in the agreement. The Company can increase the amount borrowed under this facility, without the consent of the lenders, 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 $150 Million 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 and unsubordinated 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, 2000.

The Company's obligations under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. Borrowings under this bank credit facility will generally bear interest at either (a) the greater of the Prime Rate or the Federal Funds Effective Rate plus one-half percent or (b) a Eurodollar rate plus an applicable margin (as defined within the facility) or (c) a competitively bid rate. The Company elects the basis for the interest rate at the time of each borrowing.

This credit agreement contains various affirmative and negative covenants applicable to the Company to, among other things, (i) incur certain additional indebtedness, (ii) grant certain liens, (iii) enter into certain merger or consolidation transactions and (iv) make certain investments. In addition, the Company may not directly or indirectly make any distribution in respect of its partnership interests, except those payments in connection with the 1,000,000 Unit Buy-Back Program (not to exceed $30 million in the aggregate) and distributions from Available Cash from Operating Surplus, both as defined within the agreement. The bank credit facility requires that the Company satisfy certain financial covenants at the end of each fiscal quarter: (i) maintain

Consolidated Net Worth of $750 million (as defined in the bank credit facility) and (ii) maintain a ratio of Consolidated Indebtedness (as defined within the bank credit facility) to Consolidated EBITDA (as defined within the bank credit facility) for the previous four quarter period of at least 4.0 to 1.0. The Company was in compliance with these restrictive covenants at December 31, 2000.

$150 Million 364-Day Credit Facility. Also on November 17, 2000, the Company entered into a 364-day $150 million revolving bank credit facility which may be converted into a one-year term loan at the end of the initial 364-day period. Should this facility be converted into a one-year term loan, the maturity date would be November 16, 2002. Likewise, this maturity date may be extended for an additional one-year period at the option of the Company (with the consent of the lenders), subject to the extension provisions in the agreement; therefore, the ultimate maturity date of this credit facility could be November 16, 2003. The Company can increase the amount borrowed under this facility, without the consent of the lenders, 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 $250 Million Bank Credit Facility 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 and unsubordinated 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, 2000. The Company used operating cash flows to repay the amount borrowed to retire the $350 Million Bank Credit Facility in November 2000.

Limitations on certain actions by the Company and financial condition covenants of this bank credit facility are substantially consistent with those existing for the $250 Million Multi-Year Credit Facility as described above. The Company was in compliance with the restrictive covenants at December 31, 2000.

Interest Rate Swaps

The Company's interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to the $350 Million Senior Notes and the $54 Million MBFC Loan. The Company uses interest rate swaps to manage its overall costs of financing. 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.

In March 2000, after the issuance of the $350 Million Senior Notes and the execution of the $54 Million MBFC Loan, 100% of the Company's consolidated debt were fixed-rate obligations. To maintain a balance between variable-rate and fixed-rate exposure, the Company entered into interest rate swap agreements with a notional amount of $154 million by which the Company receives payments based on a fixed-rate and pays an amount based on a floating-rate. At December 31, 2000, the Company's consolidated debt portfolio interest rate exposure was 62% fixed and 38% floating, after considering the effect of the interest rate swap agreements. The notional amount does not represent exposure to credit loss. The Company monitors its positions and the credit ratings of its counterparties. Management believes the risk of incurring a credit related loss is remote, and that if incurred, such losses would be immaterial.

The effect of these swaps (none of which are leveraged) was to decrease the Company's interest expense by $1.2 million during 2000. For further information regarding the interest rate swaps, see Note 12 of the Notes to the Consolidated Financial Statements.

Recent Accounting Developments

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities, as amended and interpreted. SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. All derivatives, whether designated in hedging relationships or not, will be required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, the changes in fair value of the derivative and the hedged item will be recognized in earnings. If the derivative is designated as a cash flow hedge, changes in the fair value of the derivative will be recorded as a component of Partners' Equity entitled Other Comprehensive Income (to the extent the hedge is effective) and will be recognized in the income statement when the hedged item affects earnings. The ineffective portion of the hedge is required to be recorded in earnings. SFAS 133 defines new requirements for designation and documentation of hedging relationships as well as ongoing effectiveness assessments in order to use hedge accounting. A derivative that does not qualify as a hedge will be recorded at fair value through earnings.

The Company expects that at January 1, 2001, it will record a $42.2 million loss in Other Comprehensive Income as a cumulative transition adjustment for derivatives (commodity contracts) designated in cash flow-type hedges prior to adopting SFAS 133. In addition, the Company expects to record a $2.1 million derivative asset and a corresponding increase to its long term debt relating to derivatives (interest rate swaps) designated in fair-value-type hedges prior to adopting SFAS 133. The fair value hedges will have no impact to earnings upon transition.

The Company will reclassify from Other Comprehensive Income $21.7 million as a charge to earnings during the first quarter of 2001 and $20.5 million as a charge to earnings during the remainder of 2001. The actual gain or loss amount to be recognized in earnings related to these commodity contracts over time is dependent upon the final settlement price associated with the commodity prices.

Amendment to Partnership Agreement

The Partnership Agreement generally authorizes the Company 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 the Unitholders. During the Subordination Period, however, the Company is limited with regards to the number of equity securities that it 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).

In April 2000, the Company mailed a Proxy Statement to its public Unitholders asking them to consider and vote for a proposal to amend the Partnership Agreement to increase the number of additional Common Units that may be issued during the Subordination Period without the approval of a Unit Majority from 22,775,000 Common Units to 47,775,000 Common Units. The primary purpose of the requested increase was to improve the future financial flexibility of the Company since 20,500,000 Common Units of the 22,775,000 Common Units available to the partnership during the Subordination Period were reserved for issuance in connection with the TNGL acquisition. At a special meeting of the Unitholders and General Partner held on June 9, 2000, this proposal was approved by 90.7% of the public Unitholders. The amendment increases the number of Common Units available (and unreserved) to the Company for general partnership purposes during the Subordination Period from 2,275,000 to 27,275,000.

MTBE Facility

The Company owns a 33.3% interest in the BEF partnership that owns the MTBE production facility located within the Company's Mont Belvieu complex. The production of MTBE is driven by oxygenated fuels programs enacted under the federal Clean Air Amendments of 1990 and other legislation. Any changes 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. On March 25, 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. In addition, legislation to amend the federal Clean Air Act has been introduced in the U.S. House of Representatives to ban the use of MTBE as a fuel additive within three years. 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.

No assurance can be given as to whether this or similar legislation ultimately will be adopted or whether the U.S. Congress or the EPA might take steps to override the MTBE ban in California.

In light of the regulatory climate, the owners of BEF are formulating a contingency plan for use of the BEF facility if MTBE were banned or significantly curtailed. The owners of BEF are exploring a possible conversion of the BEF facility from MTBE production to alkylate production. One conversion alternative is expected to result in similar operating margin as that currently anticipated from the facility if it were to remain in MTBE service. If this approach were taken, the cost to convert the facility would range from $20 million to $25 million, with the Company's share being $6.7 million to $8.3 million. A second conversion alternative would increase both production capacity and overall margin and cost between $50 million and $90 million, with the Company's share being $16.7 million to $30 million. Management anticipates that if MTBE is banned alkylate demand will rise as producers use it to replace MTBE as an octane enhancer. Greater alkylate production would be expected to increase isobutane consumption nationwide and result in improved isomerization margins for the Company.

Sun, the MTBE facility's major customer and one of the partners of BEF, has entered into a contract with BEF to take all of the MTBE production through September 2004.

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

The Company is exposed to financial market risks, including changes in interest rates with respect to a portion of its debt obligations and changes in commodity prices. The Company may use derivative financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) to mitigate these risks. The Company generally does not use derivative financial instruments for speculative (or trading) purposes.

The Company has adopted a commercial policy to manage its exposure to the risks generated by its gas processing and related NGL businesses and long-term debt. The objective of this policy is to assist the Company in achieving its profitability goals while maintaining a portfolio of conservative risk, defined as remaining within the position limits established by the General Partner. The Company will enter into risk management transactions to manage price risk, basis risk, physical risk, interest rate risk or other risks related to the energy commodities and long-term debt on both a short-term (less than 30 days) and long-term basis, not to exceed 18 months. The General Partner oversees the strategies of the Company associated with physical and financial risks, approves specific activities of the Company subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

Interest rate risk

Variable-rate Debt. At December 31, 2000 and 1999, the Company had no derivative instruments in place to cover any potential interest rate risk on its variable-rate debt obligations. Variable-rate debt obligations expose the Company to possible increases in interest expense and decreases in earnings if interest rates were to rise. During 2000 and 1999, the Company's had variable-rate long-term debt outstanding under the $200 Million, $350 Million and $150 Million 364-Day bank credit facilities. At December 31, 2000, the Company had no variable-rate debt outstanding.

If the weighted average base interest rates selected on the variable-rate long-term debt during 1999 were to have been 10% higher than the weighted average of the actual base interest rates selected, assuming no changes in weighted average variable debt levels, interest expense would have increased by approximately $1.4 million with a corresponding decrease in earnings before minority interest. If the same calculation were performed on the variable-rate long-term debt outstanding during 2000, interest expense would have increased by approximately $1.0 million with a corresponding decrease in earnings before minority interest.

Fixed-rate Debt. In March 2000, the Company entered into interest rate swaps whereby the fixed-rate of interest on a portion of the $350 Million Senior Notes and the $54 Million MBFC Loan was effectively swapped for floating-rates tied to the six month London Interbank Offering Rate ("LIBOR"). Interest rate swaps are used to manage the Company's overall costs of financing. 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.

To maintain a balance between variable-rate and fixed-rate exposure, the Company entered into interest rate swap agreements with a notional amount of $154 million by which the Company receives payments based on a fixed-rate and pays an amount based on a floating-rate. At December 31, 2000, the Company's consolidated debt portfolio interest rate exposure was 62% fixed and 38% floating, after considering the effect of the interest rate swap agreements. The notional amount does not represent exposure to credit loss. The Company monitors its positions and the credit ratings of its counterparties. Management believes the risk of incurring a credit related loss is remote, and that if incurred, such losses would be immaterial.

The effect of these swaps (none of which are leveraged) was to decrease the Company's interest expense by $1.2 million during 2000. Following is selected information on the Company's portfolio of interest rate swaps at December 31, 2000:

Interest Rate Swap Portfolio at December 31, 2000 (1)
(Dollars in millions)

Notional Amount	Period Covered	Early Termination Date (2)	Fixed / Floating Rate (3)
$ 50.0	March 2000 - March 2005	March 2001	8.25% / 7.3100%
$ 50.0	March 2000 - March 2005	March 2001 (4)	8.25% / 7.3150%
$ 54.0	March 2000 - March 2010	March 2003	8.70% / 7.6575%

(1) All swaps outstanding at December 31, 2000 were entered into for the purpose of managing a portion of the financing costs associated with fixed-rate debt.
(2) In each case, the counterparty has the option to terminate the interest rate swap on the Early Termination Date.
(3) In each case, the Company is the floating-rate payor. The floating rate was the rate in effect as of December 31, 2000.
(4) Swap was terminated by the bank effective March 15, 2001.

If the six month LIBOR rates applicable to the notional amounts of these interest rate swap agreements during 2000 were to have been 10% higher than the six month LIBOR rates actually used in the swap agreements, assuming no changes in fixed-rate debt levels, interest expense for 2000 would have increased by $0.8 million, with a corresponding decrease in earnings before minority interest.

In connection with the implementation of SFAS 133, the fair value of the interest rate swaps were recorded on the balance sheet as a $2.1 million receivable with an offsetting gain recorded in earnings on January 1, 2001. The value recorded for the interest rate swap agreements represents the fair value of these derivative instruments using current market interest rates. In accordance with SFAS 133, the value of the interest rate swaps will be redetermined each reporting period based upon then current market interest rates. The value assigned to the interest rate swap agreements is predicated upon the expected life of the swap agreements as influenced by current market interest rates. The change in the value of these instruments during each measurement period will result in either an increase or a decrease in earnings.

At December 31, 2000, the Company's fixed-rate debt obligations aggregated $404.0 million and had a fair value of $423.8 million. Since these instruments have fixed-interest rates, they do not expose the Company to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase to approximately $435.8 million if interest rates were to decline by 10% from their levels at December 31, 2000. In general, such an increase in fair value would impact earnings and cash flows only if the Company were to reacquire all or a portion of these instruments in the open market prior to their maturity.

Other. At December 31, 2000 and 1999, the Company had $60.4 million and $5.2 million invested in cash and cash equivalents, respectively. All cash equivalent investments other than cash are highly liquid, have original maturities of less than three months, and are considered to have insignificant interest rate risk.

Commodity Price Risk

The Company is exposed to commodity price risk through its gas processing and related NGL businesses. In order to effectively manage this risk, the Company may enter into swaps, forwards, commodity futures, options and other derivative commodity instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The 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.

The following table presents the hypothetical changes in fair values arising from immediate selected potential changes in the quoted market prices of derivative commodity instruments outstanding at the dates noted within the table. The fair value of the commodity futures at the dates noted below are estimates based on quoted market prices of comparable contracts and approximate the gain or loss that would have been realized if the contracts had been settled at the respective balance sheet dates.

	Asset (liability) Fair value at date indicated assuming no change in market prices	Impact of a 10% increase in market prices		Impact of a 10% decrease in market prices	
		Adjusted estimate of Fair Value	Increase(Decrease) in Fair Value due to increase in market prices	Adjusted estimate of Fair Value	Increase)Decrease) in Fair Value due to decrease in market prices
Estimated impact of changes in quoted market prices on commodity futures at: (in millions of dollars)					
December 31, 1999	$ (0.5)	$ 1.2	$ 1.7	$ (2.2)	$ (1.7)
December 31, 2000	(38.6)	(56.3)	(17.7)	(20.9)	17.7
March 12, 2001	(11.5)	(34.3)	(22.8)	11.5	23.0

The fair value of the commodity futures at December 31, 1999 was estimated at $0.5 million payable. The fair value of the commodity futures at December 31, 2000 was estimated at $38.6 million payable. The increase is primarily due to an increase in volumes hedged, a change in the composition of commodities hedged and higher natural gas prices. On March 12, 2001, the fair value of commodities hedged was $11.5 million payable. The change from December 31, 2000 was primarily due to the settlement of certain open positions, lower natural gas prices and a change in the composition of commodities hedged.

To the extent that the hedged positions are effective, gains or losses on these derivative commodity instruments would be offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table above. Beginning in January 2001 with the implementation of SFAS 133, the ineffective portion of such hedged positions will be recorded in earnings. See "Recent Accounting Developments" on page 41 for additional information regarding the accounting treatment of hedged commodity positions under SFAS 133.

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" page F-1.

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

None.

Item 10. Directors and Executive Officers of the Registrant.

Company Management

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

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 the Company, approved by all partners of the Company and not a breach by the General Partner or its Board of Directors of any duties they may owe the Company or the 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 (including its subsidiaries);
- overseeing the independence and performance of the Company's 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 the Company's policies, procedures and practices at all levels;
- reviewing areas of potential significant financial risk to the Company; 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 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 the Company's expense, special legal, accounting, or other consultants or experts it deems necessary in the performance of its duties.

Notwithstanding any limitation on its obligations or duties, the General Partner is liable, as the general partner of the Company, for all debts of the Company (to the extent not paid by the Company), except to the extent that indebtedness or other obligations incurred by the Company are made specifically non-recourse to the General Partner. Whenever possible, the General Partner intends to make any such indebtedness or other obligations non-recourse to the General Partner.

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)	68	Director and Chairman of the Board
O.S. Andras (1,3)	65	Director, President and Chief Executive Officer
Randa L. Duncan (3)	39	Director
J. R. Eagan	46	Director
J. A. Berget (1)	48	Director
Dr. Ralph S. Cunningham (2)	60	Director
Curtis R. Frasier (1)	45	Director
Lee W. Marshall, Sr. (2)	68	Director
Richard S. Snell (2)	58	Director
Richard H. Bachmann (1,3)	48	Director, Executive Vice President, Chief Legal Officer and Secretary
Albert W. Bell (3)	62	Executive Vice President, President and Chief Operating Officer of Petrochemical Division
A.J. ("Jim") Teague (3)	56	Executive Vice President, President and Chief Operating Officer of NGL Division
Michael A. Creel (3)	47	Executive Vice President, Chief Financial Officer and President and Chief Operating Officer of Natural Gas Division
William D. Ray (3)	65	Executive Vice President
Charles E. Crain (3)	67	Senior Vice President
Michael Falco (3)	64	Senior Vice President
A. Monty Wells (3)	55	Senior Vice President
Michael J. Knesek (3)	46	Vice President and Principal Accounting Officer
W. Randall Fowler (3)	44	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 as Chairman of the Board and a Director of the General Partner in April 1998. Mr. Duncan joined EPCO in 1969 and has served as Chairman of the Board of EPCO since 1979. He served as President of EPCO from 1970 to 1979 and Chief Executive Officer from 1982 to 1985.

O. S. Andras was elected as President, Chief Executive Officer and a Director of the General Partner in April 1998. Mr. Andras has served as President and Chief Executive Officer of EPCO since 1996. Mr. Andras served as President and Chief Operating Officer of EPCO from 1982 to 1996 and Executive Vice President of EPCO from 1981 to 1982. Before joining EPCO, he was employed by The Dow Chemical Company in various capacities from 1960 to 1981, including Director of Hydrocarbons.

Randa L. Duncan was elected as Group Executive Vice President and a Director of the General Partner in April 1998. Ms. Duncan served as Group Executive Vice President of EPCO from 1994 to 2001. In February 2001, she became President and Chief Executive Officer of EPCO and resigned as Group Executive Vice President of the General Partner in order to devote full attention to the responsibilities of her new position. Before joining EPCO, she was an attorney with the firms of Butler & Binion from 1988 to 1991 and Brown, Sims, Wise and White from 1991 until 1994. Ms. Duncan is the daughter of Dan L. Duncan.

J. R. (Jeri) Eagan was elected as a Director of the General Partner in October 2000. Since 1999, Ms. Eagan has served in various executive-level positions with Shell Exploration and Production Company ("SEP") and currently holds the office of Vice President Finance & Commercial Operations. From 1994 to 1999, she worked on several assignments in the London office with Shell International Petroleum Company. From 1976 to 1994, Ms. Eagan held a number of managerial and accounting positions with various Shell companies.

J. A. (Jorn) Berget was elected as a Director of the General Partner in November 2000. Since October 2000, Mr. Berget has served as Vice President and General Manager for SEP. From 1995 to October 2000, he served in various managerial positions with Shell Expro including General Manager of the Northern Business Unit in which he managed Shell assets and activities of the Brent Field in the United Kingdom. Over the past 20 years, Mr. Berget has held numerous operating, engineering, planning and managerial positions covering most aspects of SEP. 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 as 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 served as Vice Chairman of Huntsman Corporation from 1994 until 1995 and as President of Texaco Chemical Company from 1990 through 1994. Prior to joining Texaco Chemical Company, Dr. Cunningham held various executive positions with Clark Oil & Refining and Tenneco. He started his career in Exxon's refinery operations. He holds Ph.D., M.S. and B.S. degrees in Chemical Engineering. Dr. Cunningham serves as a director of Tetra Technologies, Inc. (a public energy services and chemicals company), Huntsman Corporation (a privately held petrochemical corporation), and Agrium, Inc. (a Canadian public agricultural chemicals company) and served as a director of EPCO from 1987 to 1997.

Curtis R. Frasier was elected as Director of the General Partner in November 1999. Mr. Frasier is Vice President of Shell N.A. Gas & Power, SEP. He has served in various capacities in the Shell organization since 1982 and previously served as President of Shell Midstream Enterprises. He also served as Shell's Manager of Supply Operations following assignments in the London office beginning in the Legal Department of Shell's corporate office.

Lee W. Marshall, Sr. was elected as a Director of the General Partner in April 1998. Mr. Marshall has been the Chief Executive Officer and principal stockholder of Bison International, Inc., and Bison Resources, LLC since 1991. Previously, Mr. Marshall was Executive Vice President and Chief Financial Officer of Wolverine Exploration Company and held senior management positions with Union Pacific Resources and Tenneco Oil.

Richard S. Snell was elected as 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 company in 1993. He is currently a partner with the firm of Thompson Knight Brown Parker & Leahy, L.L.P. and is a certified public accountant.

Richard H. Bachmann was elected as a Director of the General Partner in June 2000. He has served as Executive Vice President and Chief Legal Officer of the General Partner since January, 1999. Before joining EPCO, he was a partner with the firms of Snell & Smith P.C. from 1993 to 1998 and Butler & Binion from 1988 to 1993.

Albert W. Bell was elected as a Executive Vice President of the General Partner in April 1998 and serves as the President and Chief Operating Officer of the Petrochemical Division. Mr. Bell has served as Executive Vice President, Business Management of EPCO since 1994. Mr. Bell joined EPCO in 1980 as President of its Canadian subsidiary. Mr. Bell transferred to EPCO in Houston in 1988 as Vice President, Business Development and was promoted to Senior Vice President, Business Management in 1992. Prior to joining EPCO, he was employed by Continental Emsco Supply Company, Ltd. and Amoco Canada Petroleum Company, Ltd.

A.J. ("Jim") Teague was elected as a Executive Vice President of the General Partner in November, 1999 and serves as the President and Chief Operating Officer of the NGL Division of the Company. From 1998 to 1999 he served as President of Tejas Natural Gas Liquids, LLC, an affiliate of Shell.

From 1997 to 1998 he was President of Marketing and Trading for Mapco, Inc. From 1972 to 1996, he held a variety of positions with The Dow Chemical Company, including Vice President, Feedstocks.

Michael A. Creel was elected as an Executive Vice President and President and Chief Operating Officer of the Natural Gas Division 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 in investor relations, information technology and corporate risk. From 1997 to 1999 he held a series of positions, including Senior Vice President, Chief Financial Officer and Treasurer, with Tejas Energy. From 1991 to 1997 he served as Vice President and Treasurer of NorAm Energy Corp., Treasurer of Enron Oil & Gas Company, and was employed by Enron Corp. in various capacities, including Assistant Treasurer. From 1973 to 1991 he held management positions in accounting and finance within the energy and financial industries.

William D. Ray was elected as a Executive Vice President of the General Partner in April 1998. Mr. Ray has served as EPCO's Executive Vice President, Marketing and Supply since 1985. Mr. Ray served as Vice President, Supply and Distribution of EPCO from 1971 to 1973 and as EPCO's Senior Vice President, Supply, Marketing and Distribution from 1973 to 1979. Prior to joining EPCO in 1971, Mr. Ray was employed by Wanda Petroleum from 1958 to 1969 and Koch as Vice President, Marketing and Supply from 1969 to 1971.

Charles E. Crain was elected as a Senior Vice President of the General Partner in April 1998 and has served as Senior Vice President, Operations of EPCO since 1991. Mr. Crain joined EPCO in 1980 as Vice President, Process Operations. Prior to joining EPCO, Mr. Crain held positions with Shell, Air Products & Chemicals and Tenneco Chemicals.

Michael Falco was elected as a Senior Vice President of the General Partner in April 1998. Mr. Falco had served as EPCO's Senior Vice President in the business management area since 1992. Previously, Mr. Falco had a 21 year career with Tenneco Oil Company, holding a variety of positions in NGL supply and crude oil and refined products supply including 6 years as Vice President of Tenneco Oil.

A. Monty Wells was elected as a Senior Vice President of the General Partner in June 2000. Since joining EPCO in 1980, Mr. Wells has served in a number of managerial positions including Vice President of Marketing and Supply. Prior to 1980, he worked in the international natural gas liquids group at Atlantic Richfield and had responsibilities in ARCO Chemical's hydrocarbon feedstock group.

Michael J. Knesek was elected as the 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. Mr. Knesek joined EPCO in 1981 as revenue accounting manager and has served in various managerial accounting positions including general manager of accounting. Mr. Knesek has over twenty-five years of experience in corporate and partnership accounting, tax and finance.

W. Randall Fowler was elected as the Treasurer and a Vice President of the General Partner in August 2000. Mr. Fowler joined EPCO 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. Mr. Fowler has over twenty years of experience in corporate finance, investor relations, strategic planning and accounting.

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 2000. The Company believes all of these filings were satisfied by the General Partner.

Due to administrative and record keeping errors in connection with employee stock options issued by EPCO to certain officers and directors of the General Partner, in December 2000 Form 4 reports were filed by: Richard H. Bachmann with respect to being granted employee stock options in January 2000 (one transaction), by A. W. Bell with respect to being granted employee stock options in December 1999 and January 2000 (three transactions) and the exercise of employee stock options in May 1999 and August 2000 (two transactions), by Charles E. Crain with respect to being granted employee stock options in December 1999 and January and August 2000 (six transactions), by Michael A. Creel with respect to being granted employee stock options in January and August 2000 (two transactions), by Ralph S. Cunningham with respect to being granted employee stock options in January 2000 (one transaction), by W. Randall Fowler with respect to being granted employee stock options in January 2000 (one transaction), by Michael J. Knesek with respect to being granted employee stock options in December 1999 and January 2000 (three transactions) and the exercise of employee stock options in January 2000 (one transaction), by Lee W. Marshall, Sr., with respect to being granted employee stock options in January 2000 (one transaction), by William D. Ray with respect to being granted employee stock options in December 1999 and January 2000 (four transactions) and the exercise of employee stock options in January 2000 (2 transactions), by A.J. Teague with respect to being granted employee stock options in January and July 2000 (two transactions) and by A. Monty Wells with respect to being granted employee stock options in December 1999 and January 2000 (two transactions). Also in December 2000 Form 4 reports were filed by Dan L. Duncan and EPCO with respect to the issuance of employee stock options by EPCO to certain officers and directors of the General Partner in December 1999 and January, July and August 2000 (thirteen transactions).

As of March 13, 2001, 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.

The Company has no executive officers. The Company is managed by the General Partner, the executive officers of which are employees of, and the compensation of whom is paid by, EPCO. For a discussion of this related party transaction, see "EPCO Agreement" under Item 13.

Compensation of Directors

No additional remuneration is paid to employees of EPCO, Shell or the General Partner who also serve as directors of the General Partner. During fiscal 2000, the independent directors received an annual retainer of $24,000, for which each agreed to participate in four regular meetings of the Board of Directors and four Audit and Conflicts Committee meetings (plus nominal out-of-pocket expenses in connection with attending the meetings). The independent directors were also entitled to $500 per meeting when the number of Board of Directors meetings and Audit and Conflicts Committee meetings exceeded the four mentioned previously. Effective January 1, 2001, the General Partner revised its independent director compensation policy to reflect (i) an annual retainer of $18,000, (ii) $1,000 for each meeting of the Board of Directors attended by a director, (iii) $500 for each meeting of a committee of the Board of Directors attended by a committee member and (iv) an annual retainer of $500 for each chairman of a committee of the Board of Directors. Each director is fully indemnified by the Company for his or her actions associated with being a director 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 22, 2001, regarding the beneficial ownership of (a) the Common Units, (b) the Subordinated Units and (c) the Special Units of the Company by:

- all persons known by the General Partner to own beneficially more than five percent of the Common Units;
- the directors and certain executive officers of the General Partner; and
- all directors and executive officers of the General Partner as a group.

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

	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)	33,552,915	71.7%	21,409,870	100.0%	-	0.0%
Coral Energy LLC (2)	1,000,000	2.1%	-	0.0%	16,500,000	100.0%
Dan Duncan (1,3)	35,070,115	71.7%	21,409,870	100.0%	-	0.0%
O.S. Andras	180,600	0.4%	-	0.0%	-	0.0%
Randa L. Duncan	-	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	-	0.0%	-	0.0%	-	0.0%
Curtis R. Frasier	-	0.0%	-	0.0%	-	0.0%
Lee W. Marshall, Sr.	-	0.0%	-	0.0%	-	0.0%
Richard S. Snell	-	0.0%	-	0.0%	-	0.0%
Richard H. Bachmann	1,428	0.0%	-	0.0%	-	0.0%
Albert W. Bell (4)	34,252	0.1%	-	0.0%	-	0.0%
A.J. Teague (5)	58,000	0.1%	-	0.0%	-	0.0%
Michael A. Creel	5,000	0.0%	-	0.0%	-	0.0%
All directors and executive officers as a group (19 persons) (6)	35,457,498	77.6%	21,409,870	100.0%	-	0.0%

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(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 L. Duncan, a director and executive officer of the General Partner. The address of EPCO and Mr. Duncan is 2727 North Loop West, Houston, Texas 77008.
(2) Special Units were issued to Coral Energy as part of the TNGL acquisition.
(3) In addition to the Units held by EPCO, Dan Duncan has beneficial ownership of an additional 1,517,200 Common Units held by the 1998, 1999 and 2000 Trusts (see Item 13).
(4) Includes options (under an EPCO Unit option plan) to purchase 22,681 Common Units exercisable within 60 days of March 22, 2001.
(5) Includes options (under an EPCO Unit option plan) to purchase 50,000 Common Units exercisable within 60 days of March 22, 2001.
(6) Includes options (under an EPCO Unit option plan) to purchase 101,403 Common Units exercisable within 60 days of March 22, 2001.

Item 13. Certain Relationships and Related Transactions.

Relationships with EPCO and its affiliates

The Company has an extensive ongoing relationship with EPCO and its affiliates. EPCO is majority-owned and controlled by Dan L. Duncan, a director and the Chairman of the Board of the General Partner. In addition, three other members of the Board of Directors (O.S. Andras, Randa L. Duncan and Richard H. Bachmann) and the remaining executive officers (see Item 10 for a complete listing of the executive officers) of the General Partner are employees of EPCO. The principal business activity of the General Partner is to act as the managing partner of the Company.

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 L. Duncan, a director of the General Partner. The Units owned by EPCO are held by EPC Partners II, Inc. ("EPC II"), a wholly-owned subsidiary of EPCO. At December

31, 2000, EPC II owned 33,552,915 Common Units and 21,409,870 Subordinated Units, representing a 39.3% interest and 25.1% interest, respectively, in the Company. 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, the following affiliates of EPCO own Common Units (amounts as of December 31, 2000):

- Enterprise Products 1998 Unit Option Plan Trust (the "1998 Trust") held 1,150,000 Common Units. The 1998 Trust was formed for the purpose of granting options in the Company's Units to management and certain key employees. The 1998 Trust is no longer accumulating the Company's Units.
- Enterprise Products 2000 Rabbi Trust (the "2000 Trust") held 100,000 Common Units. The 2000 Trust was formed for general investment purposes and for granting additional options in Company's Units to management and certain key employees. The 2000 Trust may purchase additional Units on the open market or through privately negotiated transactions.

The Company's 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.

Another affiliate of EPCO and the Company, EPOLP 1999 Grantor Trust (the "1999 Trust"), was formed for the purpose of funding liabilities of a long-term incentive employee benefit plan. As of December 31, 2000, the 1999 Trust held 267,200 Common Units.

EPCO Agreement

The Company has no employees. All management, administrative and operating functions are performed by employees of EPCO pursuant to the EPCO Agreement entered into by EPCO, the General Partner and the Company in July 1998. Under the terms of the agreement, EPCO agreed to (i) manage the business and affairs of the Company; (ii) employ the operating personnel involved in the Company's business for which EPCO is reimbursed by the Company at cost (based upon EPCO's actual salary costs and related fringe benefits); (iii) allow the Company 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; (iv) grant an irrevocable, non-exclusive worldwide license to all of the trademarks and trade names used in its business to the Company; (v) indemnify the Company against any losses resulting from certain lawsuits; and (vi) 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 the Company for $1 per year and assigned its purchase options under such leases to the Company. EPCO is liable for the lease payments associated with these assets. Operating costs and expenses (as shown on the audited Statements of Consolidated Operations) include charges for EPCO's employees who operate the Company's various facilities.

Pursuant to the EPCO Agreement, the charges for EPCO's employees who manage the business and affairs of the Company are reimbursed only under certain circumstances. SG&A charges to EPCO resulting from the hiring of additional personnel and other costs associated with the expansion and business development activities of the Company (through the construction of new facilities or the completion of acquisitions) are reimbursed by the Company. In lieu of reimbursement for all other SG&A costs incurred by EPCO, EPCO is entitled to receive an annual Administrative Services Fee (the "EPCO Fees", initially set at $12.0 million).

The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to increases in the EPCO Fees of up to 10% each contract year (defined as August 1 to July 31) during the 10-year term of the EPCO Agreement. Since the initial contract year ending July 31, 1999, the Audit and Conflicts Committee has approved two increases in the EPCO Fees. The annual fee was increased to $13.2 million for the second contract year and subsequently raised to $14.5 million for the third contract year. The following is a summary of the SG&A amounts paid to EPCO by the Company during the last three years:

	2000	1999	1998 (1)
	(in millions of dollars)		
EPCO Fees	$ 13.8	$ 12.5	$ 5.1
Expansion-related costs reimbursed to EPCO by the Company	14.5	-	-
Total	$ 28.3	$ 12.5	$ 5.1

(1) Amount reflects the five-month period during which the EPCO Agreement was outstanding in 1998 after the initial public offering of the Company in late July 1998. As noted earlier, the initial payments made to EPCO were on the basis of $12.0 million annually ($1.0 million per month).

Other Related Party Transactions with EPCO or its affiliates

The following is a summary of the other ongoing significant relationships and transactions between EPCO and the Company and 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 $0.9 million in management fees to EPCO during 2000.
- EPCO and the Company have entered into an agreement pursuant to which EPCO provides trucking services involving the loading and transportation of NGL products for the Company. EPCO recorded $7.9 million in revenues for these services during 2000.
- In the normal course of business, the Company may, on occasion, engage in transactions with EPCO (including its wholly-owned subsidiaries) involving the buying and selling of NGL products. The Company recorded net sales to EPCO of $3.2 million during 2000.

Relationships with Shell

Shell, through its subsidiary Coral Energy, owns approximately 20.5% of the Company and 30.0% of the General Partner. 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 the gas processing assets. Under the terms of the Shell Processing Agreement, the Company has the right to process substantially all of Shell's current and future natural gas production from the Gulf of Mexico. This includes natural gas production from the developments currently referred to as deepwater. Generally, the Shell Processing Agreement grants the Company 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 raw make extracted by the Company's gas processing facilities from Shell's natural gas production from such leases; with
- the obligation to deliver to Shell the natural gas stream after the raw make is extracted.

For fiscal 2000, revenues from Shell aggregated $292.7 million while purchases from Shell totaled $736.7 million.

See Note 10 of the Notes to the Consolidated Financial Statements for additional information regarding related party transactions.

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 ad of September 22, 2000. (Exhibit 10.1 to Form 8-K filed on September 26, 2000).

*3.1 Form of Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. (Exhibit 3.2 to Registration Statement on 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 between 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 13D 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 13D 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. (Exhibit 4.2 on Form 8-K filed March 10, 2000).

*4.7 $250 Million Multi-Year Revolving Credit Agreement 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 between 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 $250 Million Multi-Year Revolving Credit Agreement) 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 $150 Million 364-Day Revolving Credit Agreement) 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. (Exhibit 4.1 to Form 8-K filed January 25, 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 between 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 between 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 between 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, dated May 13, 1998).

*10.8 Restated Operating Agreement for the Mont Belvieu Fractionation Facilities Chambers County, Texas between 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 between 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 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 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 between 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).

12.1 Computation of ratio of earnings to fixed charges for the years ended December 31, 2000, 1999, 1998, 1997 and 1996.

21.1 List of subsidiaries.

23.1 Consent of Deloitte & Touche LLP.

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* Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith

(b) Reports on Form 8-K

None.

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. (the "Company") as of December 31, 2000 and 1999, 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, 2000. 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 management of the Company. 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, 2000 and 1999, 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, 2000 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.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 28, 2001

Enterprise Products Partners L.P.
Consolidated Balance Sheets
(Dollars in Thousands)

	December 31,	
ASSETS	2000	1999
Current Assets		
Cash and cash equivalents	$ 60,409	$ 5,230
Accounts receivable - trade, net of allowance for doubtful accounts of $10,916 in 2000 and $15,897 in 1999	409,085	262,348
Accounts receivable - affiliates	6,533	56,075
Inventories	93,222	39,907
Current maturities of participation in notes receivable from unconsolidated affiliates		6,519
Prepaid and other current assets	12,143	14,459
Total current assets	581,392	384,538
Property, Plant and Equipment, Net	975,322	767,069
Investments in and Advances to Unconsolidated Affiliates	298,954	280,606
Intangible assets, net of accumulated amortization of $5,374 in 2000 and $1,345 in 1999	92,869	61,619
Other Assets	2,984	1,120
Total	$ 1,951,521	$ 1,494,952
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of long-term debt		$ 129,000
Accounts payable - trade	$ 96,559	69,294
Accounts payable - affiliate	56,447	64,780
Accrued gas payables	377,126	233,360
Accrued expenses	21,488	16,510
Other current liabilities	34,759	18,176
Total current liabilities	586,379	531,120
Long-Term Debt	404,000	166,000
Other Long-Term Liabilities	15,613	296
Minority Interest	9,570	8,071
Commitments and Contingencies		
Partners' Equity		
Common Units (46,524,515 Units outstanding at December 31, 2000 and 45,552,915 at December 31, 1999)	514,896	439,196
Subordinated Units (21,409,870 Units outstanding in 2000 and 1999)	165,253	136,618
Special Units (16,500,000 Units outstanding at December 31, 2000 and 14,500,000 Units at December 31, 1999)	251,132	210,436
Treasury Units acquired by Trust, at cost (267,200 Units outstanding at December 31, 2000 and 1999)	(4,727)	(4,727)
General Partner	9,405	7,942
Total Partners' Equity	935,959	789,465
Total	$ 1,951,521	$ 1,494,952

See Notes to Consolidated Financial Statements

Enterprise Products Partners L.P.
Statements of Consolidated Operations
(Amounts in Thousands, Except per Unit Amounts)

	Years Ended December 31,		
	2000	1999	1998
REVENUES			
Revenues from consolidated operations	$ 3,049,020	$ 1,332,979	$ 738,902
Equity income in unconsolidated affiliates	24,119	13,477	15,671
Total	3,073,139	1,346,456	754,573
COST AND EXPENSES			
Operating costs and expenses	2,801,060	1,201,605	685,884
Selling, general and administrative	28,345	12,500	18,216
Total	2,829,405	1,214,105	704,100
OPERATING INCOME	243,734	132,351	50,473
OTHER INCOME (EXPENSE)			
Interest expense	(33,329)	(16,439)	(15,057)
Interest income from unconsolidated affiliates	1,787	1,667	809
Dividend income from unconsolidated affiliates	7,091	3,435	-
Interest income - other	3,748	886	772
Other, net	(272)	(379)	358
Other income (expense)	(20,975)	(10,830)	(13,118)
INCOME BEFORE EXTRAORDINARY ITEM AND MINORITY INTEREST	222,759	121,521	37,355
Extraordinary charge on early extinguishment of debt			(27,176)
INCOME BEFORE MINORITY INTEREST	222,759	121,521	10,179
MINORITY INTEREST	(2,253)	(1,226)	(102)
NET INCOME	$ 220,506	$ 120,295	$ 10,077
BASIC EARNINGS PER UNIT			
Income before extraordinary item and minority interest	$ 3.28	$ 1.80	$ 0.62
Net income	$ 3.25	$ 1.79	$ 0.17
DILUTED EARNINGS PER UNIT			
Income before extraordinary item and minority interest	$ 2.67	$ 1.65	$ 0.62
Net income	$ 2.64	$ 1.64	$ 0.17

See Notes to Consolidated Financial Statements

Enterprise Products Partners L.P.
Statements of Consolidated Cash Flows
(Amounts in Thousands)

	Year Ended December 31,		
	2000	1999	1998
OPERATING ACTIVITIES			
Net income	$ 220,506	$ 120,295	$ 10,077
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:			
Extraordinary item - early extinguishment of debt			27,176
Depreciation and amortization	41,016	25,315	19,194
Equity in income of unconsolidated affiliates	(24,119)	(13,477)	(15,671)
Distributions received from unconsolidated affiliates	37,267	6,008	9,117
Leases paid by EPCO	10,537	10,557	4,010
Minority interest	2,253	1,226	102
(Gain) loss on sale of assets	2,270	123	(276)
Net effect of changes in operating accounts	70,958	27,906	(63,171)
Operating activities cash flows	360,688	177,953	(9,442)
INVESTING ACTIVITIES			
Capital expenditures	(243,913)	(21,234)	(8,360)
Proceeds from sale of assets	92	8	1,887
Business acquisitions, net of cash acquired		(208,095)	
Participation in notes receivable from unconsolidated affiliates:			
Purchase of notes receivable			(33,725)
Collection of notes receivable	6,519	19,979	7,228
Investments in and advances to unconsolidated affiliates	(31,496)	(61,887)	(26,842)
Investing activities cash flows	(268,798)	(271,229)	(59,812)
FINANCING ACTIVITIES			
Net proceeds from sale of common units			243,296
Long-term debt borrowings	599,000	350,000	90,000
Long-term debt repayments	(490,000)	(154,923)	(257,413)
Debt issuance costs	(4,043)	(3,135)	(1,735)
Net decrease in restricted cash			4,522
Cash dividends paid to partners	(139,577)	(111,758)	(21,645)
Cash dividends paid to minority interest by Operating Partnership	(1,429)	(1,140)	
Units acquired by consolidated trust		(4,727)	
Unit repurchases	(770)		
Cash contributions from EPCO to minority interest	108	86	2,478
Financing activities cash flows	(36,711)	74,403	59,503
CASH CONTRIBUTION FROM EPCO			14,913
NET CHANGE IN CASH AND CASH EQUIVALENTS	55,179	(18,873)	5,162
CASH AND CASH EQUIVALENTS, JANUARY 1	5,230	24,103	18,941
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 60,409	$ 5,230	$ 24,103

See Notes to Consolidated Financial Statements

Enterprise Products Partners L.P.
Statements of Consolidated Partners' Equity
(Amounts in Thousands)

	Limited Partners					
	Common Units	Subordinated Units	Special Units	Treasury Units	General Partner	Total
Balances, December 31, 1997	$ 188,503	$ 120,263			$ 3,119	$ 311,885
Net income	5,641	4,335			101	10,077
Cash contributions from EPCO	7,519	4,813			2,581	14,913
Leases paid by EPCO after public offering	2,701	1,269			40	4,010
Proceeds from sale of Common Units	243,296					243,296
Cash distributions to Unitholders	(14,578)	(6,851)			(216)	(21,645)
Balances, 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 Coral Energy, LLC in connection with TNGL acquisition			$ 210,436		2,126	212,562
Cash distributions to Unitholders	(81,993)	(28,647)			(1,118)	(111,758)
Units acquired by consolidated				$ (4,727)		(4,727)
Balances, 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 Coral Energy, LLC in connection with contingency agreement			55,241		557	55,798
Conversion of 1.0 million Coral Energy, LLC 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)
Balances, December 31, 2000	$ 514,896	$ 165,253	$ 251,132	$ (4,727)	$ 9,405	$ 935,959

See Notes to Consolidated Financial Statements

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ENTERPRISE PRODUCTS PARTNERS L.P. and its consolidated subsidiaries (the "Company") is a publicly-traded Delaware limited partnership listed on the New York Stock Exchange under symbol "EPD". The Company and its 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"). The Company conducts substantially all of its business through its Operating Partnership, in which it owns 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. Both the Company and the General Partner are subsidiaries of EPCO.

Prior to their consolidation, EPCO and its affiliated 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 the 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, the Company became the successor to the NGL operations of EPCO.

Effective July 27, 1998, the Company filed a registration statement pursuant to an initial public offering of 12,000,000 Common Units. The Common Units sold for $22 per unit. The Company received approximately $243.3 million after underwriting commissions of $16.8 million and expenses of approximately $3.9 million.

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 the accounts of the Company and its majority-owned subsidiaries, after elimination of all material intercompany accounts and transactions. In general, investments in which the Company owns 20% to 50% and exercises significant influence over operating and financial policies are accounted for using the equity method. Investments in which the Company owns less than 20% are accounted for using the cost method unless the Company exercises 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, the Company considers all highly liquid debt instruments with an original maturity of less than three months at the date of purchase to be cash equivalents.

DERIVATIVE 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. Prior to the implementation of SFAS 133 in January 2001 (see Note 12), the Company deferred the impact of changes in the market value of these contracts until such time as the hedged transaction was settled. At that time, the impact of the changes in fair value of these contracts would be recognized in earnings.

Under SFAS 133, the Company is required to recognize in earnings changes in fair value of these derivative instruments that are not offset by changes in the fair value of the inventories, firm commitments and certain anticipated transactions.

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 the Company to commodity or interest rate risk and the hedging instrument must reduce that exposure and meet the hedging requirements of SFAS 133. Any contracts held or issued that do not meet the requirements of a hedge (as defined by SFAS 133) will be recorded at fair value on the balance sheet and any changes in that fair value recognized in earnings. If a contract designated as a hedge of commodity risk is terminated, the associated gain or loss is deferred and recognized in income when the firm commitment or anticipated transaction affects earnings. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

DOLLAR AMOUNTS (except per Unit amounts) presented in the tabulations within the notes to the Company's 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 Units 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 Units, Subordinated Units, 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 unit distributions until they are converted to Common Units. During 2000, 1.0 million Special Units were converted into 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 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, 2000 were not significant to the consolidated financial statements. Costs of environmental compliance and monitoring aggregated $1.1 million, $0.9 million and $1.4 million for the years ended December 31, 2000, 1999 and 1998. The Company's estimated liability for environmental remediation is not discounted.

EXCESS COST OVER UNDERLYING EQUITY IN NET ASSETS (or "excess cost") denotes the excess of the Company's cost (purchase price) over the underlying equity in net assets of K/D/S Promix, LLC and Dixie Pipeline Company. The excess cost associated with the Company's investment in K/D/S Promix is being amortized using the straight-line method over a period of 20 years. The excess cost related to the Company's investment in Dixie Pipeline Company is being amortized using the straight-line method over a period of 35 years due to its classification as a pipeline asset. The excess cost of K/D/S Promix, LLC and Dixie Pipeline Company is reflected in the Company's 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 products between parties to satisfy timing and logistical needs of the parties. NGLs and NGL products borrowed from the Company under such agreements are included in inventories, and NGLs and NGL products loaned to the Company under such agreements are accrued as a liability in accrued gas payables.

FEDERAL INCOME TAXES are not provided because the Company is a master limited partnership. As a result, the Company's 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 the accompanying financial statements of the Company. State income taxes are not material to the Company. 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, consisting of NGLs and NGL products, are carried at the lower of average cost or market.

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, both of which were initially recorded in 1999. The $89.3 million in intangibles related to the natural gas processing agreement is being amortized over the contract term. The $9.0 million excess cost of the purchase price over the fair market value of the assets acquired from Mont Belvieu Associates is being amortized over 20 years. See Note 2 for additional information regarding these assets.

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. The Company has 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. 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. 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.

REVENUE is recognized by the Company's five reportable business segments using the following criteria: (a) persuasive evidence of an exchange arrangement exists, (b) delivery has occurred or services have been rendered, (c) the buyer's price is fixed or determinable and (d) 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 the Fractionation segment, the Company enters into NGL fractionation contracts, isomerization contracts and propylene fractionation and merchant contracts. Under the propylene merchant contracts, revenue is recognized once the products have been effectively delivered to the third party. Regarding the various NGL and propylene fractionation and isomerization contracts whereby a toll fee is collected, revenue is recognized once the contract services have been performed. Fractionation and isomerization contracts 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 these operations. The propylene merchant contracts are based upon market rates or spot prices as determined in the individual contracts.

As part of its Pipeline operations, the Company enters into pipeline contracts, storage contracts and product loading contracts. Under the pipeline contracts, revenue is recognized once the products have been physically delivered to the third party through the pipeline. Under the storage contracts whereby a fee is collected based upon the number of days in storage multiplied by the storage rate by product, revenue is recognized ratably over the length of the storage contract. In the absence of a set period under contractual terms, storage revenue is recognized based upon a daily rate as specified in the applicable contract. Revenues for product loading contracts (applicable to the operations of EPIK, an unconsolidated affiliate) are recorded once the loading services have been performed. Pipeline contracts typically include a throughput fee per gallon as stated in the contract or as regulated by the Federal Energy Regulatory Committee ("FERC"). Storage and loading rates are stated in the individual contracts.

As part of its Processing business, the Company entered into a 20-year natural gas processing agreement with Shell ("Shell Processing Agreement"), whereby the Company has 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. This includes natural gas production from the developments currently referred to as deepwater. This contract serves as an arrangement between the Company and Shell. In addition to the Shell Processing Agreement, the Company has contracts to process natural gas for other third parties.

Under these contracts, the price of the Company's services is based upon contractual terms with Shell or other third parties and may be specified as either (i) a cash fee or (ii) 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, the Company records revenue once the natural gas has been processed and sent back to Shell or the other third parties (i.e., delivery has taken place).

If the contract stipulates that the Company retains a percentage of the NGLs extracted as payment for its services, the Processing segment's merchant business records revenues when it sells and delivers such NGL products to third parties. The Processing segment's merchant business may also buy and sell NGLs in the open market. The revenues recorded for these contracts are recognized upon delivery of the products specified in each individual contract. Pricing under both types of arrangements is based upon market prices plus or minus other determining factors specific to each contract such as location pricing differentials.

The Octane Enhancement segment consists of the Company's 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 has agreed to purchase 100 percent of the MTBE output at market-related negotiated prices. Under the contract with Sun, 100 percent of the MTBE production is delivered to Sun and Sun is obligated to take title to the product. Revenue is recognized once the product has been physically delivered to Sun.

The Other segment is primarily comprised of fee-based marketing services. The Company performs NGL marketing services for a small number of customers for which it charges 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 marketing 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. Actual results could differ from these estimates.

2. ACQUISITIONS

Acquisition of Kinder Morgan and EPCO interest in Mont Belvieu Fractionation Facility in July 1999

Effective July 1, 1999, the Company acquired Kinder Morgan Operating LP "A"'s 25% interest and EPCO's 0.5% interest in a 210,000 BPD NGL fractionation facility located in Mont Belvieu, Texas for approximately $42 million in cash and the assumption of approximately $ 4 million of debt. The $42 million in cash was funded with borrowings under the Company's $350 million bank credit facility.

The acquisition was accounted for under the purchase method of accounting and, accordingly, the purchase price has been allocated to the assets purchased and liabilities assumed based on their estimated fair value at July 1, 1999 as follows (in millions):

Property	$ 36.2
Intangible asset	9.0
Liabilities	(3.7)
Total purchase price	$ 41.5

The intangible asset represents the excess cost of purchase price over the fair market value of the assets acquired and is being amortized over 20 years. For the years ending December 31, 2000 and 1999, $0.5 million and $0.2 million of such amortization was charged to operating costs and expenses.

Acquisition of Tejas Natural Gas Liquids, LLC in August 1999

Effective August 1, 1999, the Company acquired Tejas Natural Gas Liquids, LLC ("TNGL") from a subsidiary of Tejas Energy, LLC, now Coral Energy, LLC, an affiliate of Shell Oil Company ("Shell") for $166 million in cash and the issuance of 14.5 million non-distribution bearing, convertible Special Units valued at $210.4 million. All references hereafter to "Shell", unless the context indicates otherwise, shall refer collectively to Shell Oil Company, its subsidiaries and affiliates. TNGL engages in natural gas processing and NGL fractionation, transportation, storage and marketing in Louisiana and Mississippi. TNGL has varying interests in eleven natural gas processing plants, four NGL fractionation facilities, four NGL storage facilities, approximately 1,500 miles of pipelines and is party to the Shell Processing Agreement, a 20 year natural gas processing agreement.

The cash portion of the purchase price was funded with borrowings under the Company's $350 million bank credit facility. The value of the 14.5 million non-distribution bearing, convertible Special Units was determined using both present value and Black Scholes Model methodologies and was within a range provided by an independent investment banker.

In addition to the initial purchase price, the Company agreed to issue to Shell 6.0 million non-distribution bearing, convertible Contingency Units provided that Shell meets certain performance criteria in calendar years 2000 and 2001 (see Note 7). If Shell met the performance criteria for 2000, 3.0 million of the Contingency Units would be issued; likewise, if Shell met the 2001 goals, the remaining 3.0 million Contingency Units would be issued. On June 28, 2000, Shell met the performance criteria for 2000 and in accordance with its contingent Unit agreement with Shell, the Company issued the 3.0 million Contingency Units (deemed "Special Units" once they are issued) on August 1, 2000. The value of these new Special Units was determined to be $55.2 million using present value techniques.

The acquisition was accounted for under the purchase method of accounting and, accordingly, the purchase price has been allocated to the assets acquired and liabilities assumed based on their estimated fair value at August 1, 1999. The following table reflects the allocation of the initial purchase price, the value of the 3.0 million new Special Units and purchase accounting adjustments (in millions):

Current Assets	$ 124.3
Investments	128.6
Property	216.9
Intangible asset	89.3
Liabilities	(147.4)
Total Purchase Price	$ 411.7

The $89.3 million intangible asset is the value assigned to the Shell Processing Agreement and is being amortized over the contract term. For the years ending December 31, 2000 and 1999, $3.6 million and $1.1 million of such amortization was charged to operating costs and expenses. Beginning in December 2000, such amortization increased to $0.4 million per month. The assets, liabilities and results of operations of TNGL are included with those of the Company as of August 1, 1999. If the remainder of the Contingency Units are issued in 2001 (or at such later date as agreed to by the parties), the purchase price and value of the Shell Processing Agreement will be adjusted accordingly. Historical information for periods prior to August 1, 1999 do not reflect any impact associated with the TNGL acquisition.

Pro Forma effect of Acquisitions

The following table presents unaudited pro forma information for the years ended December 31, 1999 and 1998 as if the acquisition of TNGL and the Mont Belvieu fractionator facility had been made as of the beginning of the periods presented. The pro forma information is based upon information currently available to and certain estimates and assumptions by management and, as a result, are not necessarily indicative of the financial results of the Company had the transactions actually occurred on these dates. Likewise, the unaudited pro forma information is not necessarily indicative of future financial results of the Company.

	1999	1998
Revenues	$ 1,726,516	$ 1,366,450
Income before extraordinary item and minority interest	$ 136,415	$ 42,054
Net income	$ 135,037	$ 14,728
Allocation of net income to Limited partners	$ 133,687	$ 14,581
General Partner	$ 1,350	$ 147
Units used in earning per Unit calculations Basic	66,710	60,124
Diluted	81,210	74,624
Income per Unit before minority interest Basic	$ 2.02	$ 0.69
Diluted	$ 1.66	$ 0.56
Net income per Unit Basic	$ 2.00	$ 0.24
Diluted	$ 1.65	$ 0.20

Acadian Gas, LLC

On September 25, 2000, the Company announced that it had executed a definitive agreement to purchase Acadian Gas, LLC ("Acadian") from Coral Energy, an affiliate of Shell, for $226 million in cash, inclusive of working capital. Acadian's assets are comprised of the 438-mile Acadian, 577-mile Cypress and 27-mile Evangeline natural gas pipeline systems, which together have over one billion cubic feet ("Bcf") per day of capacity. These natural gas pipeline systems are wholly-owned by Acadian with the exception of the Evangeline system in which Acadian holds an approximate 49.5% interest. The system includes a leased natural gas storage facility at Napoleonville, Louisiana. Completion of this transaction is subject to certain conditions, including regulatory approvals. The purchase is expected to be completed during the first quarter of 2001.

3. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment and accumulated depreciation are as follows:

	Estimated Useful Life in Years	2000	1999
Plants and pipelines	5-35	$1,108,519	$ 875,773
Underground and other storage facilities	5-35	109,760	103,578
Transportation equipment	3-35	2,620	2,117
Land		14,805	14,748
Construction in progress		34,358	32,810
Total		1,270,062	1,029,026
Less accumulated depreciation		294,740	261,957
Property, plant and equipment, net		$ 975,322	$ 767,069

Depreciation expense for the years ended December 31, 2000, 1999 and 1998 was $33.3 million, $22.4 million and $18.6 million, respectively.

4. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

The Company owns interests in a number of related businesses that are accounted for under the equity method 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 the Company's business segments, see Note 15.

At December 31, 2000, the Company's Fractionation operating segment included the following unconsolidated affiliates (all accounted for using the equity method):

- Baton Rouge Fractionators LLC ("BRF") - an approximate 32.25% interest in a natural gas liquid ("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 that became operational in July 2000.

- K/D/S Promix LLC ("Promix") - a 33.33% interest in a NGL fractionation facility and related storage facilities located in south Louisiana. The Company's investment includes excess cost over the underlying equity in the net assets of Promix of $8.0 million which is being amortized using the straight-line method over a period of 20 years. The unamortized balance of excess cost over the underlying equity in the net assets of Promix was $7.4 million at December 31, 2000.

The combined results of operations for the last three years and financial position for the last two years of the Company's Fractionation equity method investments are summarized below:

	As of or for the Year Ended December 31, 2000	1999	1998
BALANCE SHEET DATA:			
Current assets	$ 31,168	$ 47,235	
Property, plant and equipment, net	264,618	245,855	
Other assets	67	854	
Total assets	$ 295,853	$ 293,944	
Current liabilities	$ 13,661	$ 32,646	
Other liabilities	-	-	
Combined equity	282,192	261,298	
Total liabilities and combined equity	$ 295,853	$ 293,944	
INCOME STATEMENT DATA:			
Revenues	$ 71,287	$ 36,293	$ 31,881
Gross operating margin	33,240	14,970	12,154
Operating income	19,997	5,930	9,840
Net income	20,661	4,200	9,271

At December 31, 2000, the Company's Pipeline operating segment included the following unconsolidated affiliates (all 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. The Company owns 50% of EPIK Gas Liquids, LLC which owns 1% of such facilities. The Company does not exercise control over these entities; therefore, it is precluded from consolidating such entities into its financial statements.

- Wilprise Pipeline Company, LLC ("Wilprise") - a 37.35% interest in a NGL pipeline system located in southeastern Louisiana.

- Tri-States NGL Pipeline LLC ("Tri-States") - an aggregate 33.33% interest in a NGL pipeline system located in Louisiana, Mississippi, and Alabama.

- Belle Rose NGL Pipeline LLC ("Belle Rose") - a 41.7% interest in a NGL pipeline system located in south Louisiana.

- Dixie Pipeline Company ("Dixie") - a 19.9% interest in a corporation owning a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina. The Company acquired an 11.5% interest in Dixie as a result of the TNGL acquisition. On October 6, 2000, the Company purchased an additional 8.4% interest in Dixie from Conoco Pipe Line Company for $19.4 million in cash. As a result of this purchase, the Company is able to exercise significant influence over Dixie's operating and financial activities and changed its method of accounting for the investment in Dixie from the cost method to the equity method. This change in accounting methods for Dixie resulted in a immaterial cumulative effect of $0.2 million in expense being recorded in 2000 relating to the period in which the Company held an ownership interest in Dixie during 1999. The cumulative effect is recorded as a reduction of current year equity earnings from Dixie due to its immaterial nature.

  As a result of changing from the cost method to the equity method, the Company's investment in Dixie includes excess cost over the underlying equity in the net assets of $37.4 million which is being amortized using the straight-line method over a period of 35 years due to its classification as a pipeline asset. During 2000, the Company recorded amortization expense associated with this excess cost of $0.9 million (including the cumulative effect of $0.2 million related to 1999 mentioned previously), which is reflected in the equity earnings of Dixie. The unamortized balance of excess cost over the underlying equity in the net assets of Dixie was $36.3 million at December 31, 2000.

The combined results of operations for the last three years and financial position for the last two years of the Company's Pipeline equity method investments are summarized below:

	As of or for the Year Ended December 31,		
	2000	1999	1998
BALANCE SHEET DATA:			
Current assets	$ 25,464	$ 26,483	
Property, plant and equipment, net	188,724	193,237	
Other assets	3,666	3,172	
Total assets	$ 217,854	$ 222,892	
Current liabilities	$ 31,085	$ 32,873	
Other liabilities	4,018	4,317	
Combined equity	182,751	185,702	
Total liabilities and combined equity	$ 217,854	$ 222,892	
INCOME STATEMENT DATA:			
Revenues	$ 96,270	$ 52,386	$ 3,982
Gross operating margin	51,414	24,845	1,869
Operating income	41,757	19,988	1,775
Net income	31,241	15,637	1,777

At December 31, 2000, the Octane Enhancement operating segment included Belvieu Environmental Fuels ("BEF") in which the Company owns a 33.33% interest. BEF is a partnership that owns a methyl tertiary butyl ether ("MTBE") production facility located within the Company's Mont Belvieu complex. The production of MTBE is driven by oxygenated fuels programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation. Any changes to these programs that enable localities to elect not to 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 the Company's 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 of these detections have been well below levels of public health concern, there have been actions calling for the phase-out of MTBE in motor gasoline in various federal and state governmental agencies.

In light of these developments, the owners of BEF are 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. 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 can range from $20 million to $90 million, with the Company's share of these costs ranging from $6.7 million to $30 million.

BEF has a ten-year off-take agreement with Sun Company, Inc. ("Sun") under which Sun is required to purchase all of the plant's MTBE production through September 2004. Through May 31, 2000, Sun was required to pay for the MTBE using the following pricing structure:

- for the first 193,450,000 gallons of MTBE produced per contract year, the higher of (i) a contractual floor price or (ii) a toll or spot market-related price (as defined within the agreement); and,
- a spot market-related price for all volumes in excess of this amount.

The floor price was a price sufficient to cover essentially all of BEF's operating costs plus principal and interest payments on its bank term loan. In general, Sun paid the floor price during the periods in which it was in effect. Beginning June 1, 2000 through the remainder of the agreement, the pricing on all MTBE delivered to Sun changed to a market-related negotiated price which generally approximates Gulf Coast MTBE spot prices. The market-related negotiated price is subject to fluctuations in commodity prices for MTBE. MTBE spot prices are generally higher during the April to September period of each year which corresponds with the summer driving season.

The results of operations for the last three years and financial position for the last two years of the Company's investments in BEF are summarized below:

	As of or for the Year Ended December 31,		
	2000	1999	1998
BALANCE SHEET DATA:			
Current Assets	$ 20,640	$ 44,261	
Property, plant and equipment, net	150,603	161,390	
Other assets	11,439	8,313	
Total assets	$ 182,682	$ 213,964	
Current liabilities	$ 8,042	$ 41,317	
Other liabilities	5,779	4,323	
Combined equity	168,861	168,324	
Total liabilities and combined equity	$ 182,682	$ 213,964	
INCOME STATEMENT DATA:			
Revenues	$ 258,180	$ 193,219	$ 182,001
Gross operating margin	43,328	43,479	47,262
Operating income	30,529	30,025	33,930
Income before accounting change	31,220	29,029	29,401
Net income	31,220	24,550	29,401

The Company's 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 LLC owning a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines in Louisiana. This investment is accounted for using the cost method.

During the third quarter of 1999, the Company acquired the remaining interests in Mont Belvieu Associates, 51%, ("MBA") and Entell NGL Services, LLC, 50%, ("Entell"). After the acquisition of the remaining interests, MBA was dissolved by the Company and Entell became a wholly owned subsidiary of the Company.

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

	December 31, 2000	December 31, 1999
Accounted for on equity basis:		
BEF	$ 58,677	$ 63,004
Promix	48,670	50,496
BRF	30,599	36,789
Tri-States	27,138	28,887
EPIK	15,998	15,258
Belle Rose	11,653	12,064
BRPC	25,925	11,825
Wilprise	9,156	9,283
Dixie	38,138	20,000
Accounted for on cost basis:		
VESCO	33,000	33,000
Total	$ 298,954	$ 280,606

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

	2000	1999	1998
BEF	$ 10,407	$ 8,183	$ 9,801
MBA		1,256	5,213
BRF	1,369	(336)	(91)
BRPC	(284)	16	
EPIK	3,273	1,173	748
Wilprise	497	160	
Tri-States	2,499	1,035	
Promix	5,306	630	
Belle Rose	301	(29)	
Dixie	751		
Other		1,389	
Total	$ 24,119	$ 13,477	$ 15,671

At December 31, 2000, the Company's share of accumulated earnings of unconsolidated affiliates that had not been remitted to the Company was approximately $26.7 million.

5. NOTES RECEIVABLE FROM UNCONSOLIDATED AFFILIATES

At December 31, 1999, the Company held a participation interest in the bank loan of BEF for $6.5 million. The BEF bank loan matured on May 31, 2000. With BEF's final payment, the Company's receivable relating to its participation in the BEF note was extinguished.

6. LONG-TERM DEBT

Long-term debt consisted of the following at:

	December 31, 2000	December 31, 1999
Borrowings under:		
$200 Million Bank Credit Facility (1)		$ 129,000
$350 Million Bank Credit Facility (1)		166,000
$350 Million Senior Notes (2)	$ 350,000	
$54 Million MBFC Loan (3)	54,000	
Total	404,000	295,000
Less current maturities of long-term debt		129,000
Long-term debt (4)	$ 404,000	$ 166,000

Notes to long-term debt table:

(1) Revolving credit facility closed as of December 31, 2000
(2) 8.25% fixed-rate, due March 2005
(3) 8.70% fixed-rate, due March 2010
(4) 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, 2000. See below for a complete description of these new facilities

During the first quarter of 2001, the Company issued $450 Million in additional Senior Notes and filed a $500 million universal registration statement with the Securities and Exchange Commission. For a description of these subsequent events, see Note 16.

At December 31, 2000, the Company had a total of $50 million of standby letters of credit available under its $250 Million Multi-Year Credit Facility (described below) of which none were 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 $350 Million Senior Notes, $54 Million MBFC Loan, $250 Million Multi-Year Credit Facility and $150 Million 364-Day Credit Facility. In the descriptions that follow, the term "MLP" denotes Enterprise Products Partners L.P. in this guarantor role.

$200 Million Bank Credit Facility. On July 27, 1998, the Company entered into a $200 million bank credit facility that included a $50 million working capital facility and a $150 million revolving credit facility. On March 15, 2000, the Company used $169 million of the proceeds from the issuance of the $350 Million Senior Notes to retire this credit facility in accordance with its agreement with the banks.

During the period in which this bank credit facility was active, the Company elected the basis of the interest rate at the time of each borrowing. Interest rates ranged from 7.07% to 7.31% during 2000, with the weighted-average interest rate charged during 2000 being 7.28%.

$350 Million Bank Credit Facility. On July 28, 1999, the Company entered into a $350 Million Bank Credit Facility that included a $50 million working capital facility, a $300 million revolving credit facility and a sublimit of $40 million for letters of credit. On November 17, 2000, this facility was retired using funds available under the Company's new $150 Million 364-Day Credit Facility (described below) in accordance with its agreement with the banks.

During the period in which this bank credit facility was active, the Company elected the basis of the interest rate at the time of each borrowing. Interest rates ranged from 7.07% to 7.31% during 2000, with the weighted-average interest rate charged during 2000 being 7.28%.

$350 Million Senior Notes. On March 13, 2000, the Company 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 Company received proceeds, net of underwriting discounts and commissions, of approximately $347.7 million. The proceeds were used to pay the entire $169 million outstanding principal balance on the $200 Million Bank Credit Facility and $179 million of the then $226 million outstanding principal balance on the $350 Million Bank Credit Facility.

The $350 Million Senior Notes 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 the ability of the Company, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. The Company was in compliance with the restrictive covenants at December 31, 2000.

The issuance of the $350 Million Senior Notes was a takedown under the December 1999 Registration Statement; therefore, the amount of securities available was reduced to $450 million. The remaining amount available under the December 1999 Registration Statement was used to issue the $450 Million Senior Notes in January 2001 (see Note 16 "Subsequent Events" below for a brief description of the $450 Million Senior Notes).

After including the effect of interest rate swaps related to this debt instrument, interest rates for the $350 Million Senior Notes ranged from 7.88% to 8.05% during 2000, and the weighted-average interest rate at December 31, 2000 was 8.00%.

$54 Million MBFC Loan. On March 27, 2000, the Company executed a $54 million loan agreement with the MBFC which was funded with proceeds from the sale of Taxable Industrial Revenue Bonds ("Bonds") by the MBFC. The Bonds issued by the MBFC are 10-year bonds with a maturity date of March 1, 2010 and bear a fixed-rate interest coupon of 8.70%. The Company received proceeds from the sale of the Bonds, net of underwriting discounts and commissions, of approximately $53.6 million. The proceeds were used to pay the then $47 million outstanding principal balance on the $350 Million Bank Credit Facility and for working capital and other general partnership purposes. In general, the proceeds of the Bonds were used to reimburse the Company for costs incurred in acquiring and constructing the Pascagoula, Mississippi natural gas processing plant.

The Bonds were issued at par and are subject to a make-whole redemption right by the Company. The Bonds are guaranteed by the MLP through an unsecured and unsubordinated guarantee. The loan agreement contains certain covenants including maintaining appropriate levels of insurance on the Pascagoula natural gas processing facility and restrictions regarding mergers. The Company was in compliance with the restrictive covenants at December 31, 2000.

After including the effect of interest rate swaps related to this debt instrument, interest rates for the Bonds ranged from 7.26% to 7.66% during 2000, and the weighted-average interest rate at December 31, 2000 was 7.43%.

$250 Million Multi-Year Credit Facility. On November 17, 2000, the Company entered into a $250 million five-year revolving credit facility that includes a sublimit of $50 million for letters of credit. The November 17, 2005 maturity date may be extended for one year at the Company's option with the consent of the lenders, subject to the extension provisions in the agreement. The Company can increase the amount borrowed under this facility, without the consent of the lenders, 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 $150 Million 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 and unsubordinated 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, 2000.

The Company's obligations under this bank credit facility are unsecured general obligations and are non-recourse to the General Partner. Borrowings under this bank credit facility will generally bear interest at either (a) the greater of the Prime Rate or the Federal Funds Effective Rate plus one-half percent or (b) a Eurodollar rate plus an applicable margin (as defined within the facility) or (c) a competitively bid rate. The Company elects the basis for the interest rate at the time of each borrowing.

This credit agreement contains various affirmative and negative covenants applicable to the Company to, among other things, (i) incur certain additional indebtedness, (ii) grant certain liens, (iii) enter into certain merger or consolidation transactions and (iv) make certain investments. In addition, the Company may not directly or indirectly make any distribution in respect of its partnership interests, except those payments in connection with the 1,000,000 Unit Buy-Back Program (not to exceed $30 million in the aggregate) and distributions from Available Cash from Operating Surplus, both as defined within the agreement. The bank credit facility requires that the Company satisfy certain financial covenants at the end of each fiscal quarter: (i) maintain Consolidated Net Worth of $750 million (as defined in the bank credit facility) and (ii) maintain a ratio of Consolidated Indebtedness (as defined within the bank credit facility) to Consolidated EBITDA (as defined within the bank credit facility) for the previous four quarter period of at least 4.0 to 1.0. The Company was in compliance with these restrictive covenants at December 31, 2000.

$150 Million 364-Day Credit Facility. Also on November 17, 2000, the Company entered into a 364-day $150 million revolving bank credit facility which may be converted into a one-year term loan at the end of the initial 364-day period. Should this facility be converted into a one-year term loan, the maturity date would be November 16, 2002. Likewise, this maturity date may be extended for an additional one-year period at the option of the Company (with the consent of the lenders), subject to the extension provisions in the agreement; therefore, the ultimate maturity date of this credit facility could be November 16, 2003. The Company can increase the amount borrowed under this facility, without the consent of the lenders, 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 $250 Million Bank Credit Facility 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 and unsubordinated 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, 2000. The Company used operating cash flows to repay the amount borrowed to retire the $350 Million Bank Credit Facility in November 2000. For the period in which the Company had an outstanding principal balance under this credit facility, the interest rate was 7.19%.

Limitations on certain actions by the Company and financial condition covenants of this bank credit facility are substantially consistent with those existing for the $250 Million Multi-Year Credit Facility as described above. The Company was in compliance with the restrictive covenants at December 31, 2000.

Extraordinary Item - Early Extinguishment of Debt

On July 31, 1998, the Company used $243.3 million of proceeds from the sale of Common Units and $13.3 million of borrowings from the $200 Million Bank Credit Facility to retire $256.6 million of debt that was assumed from EPCO. In connection with the repayment of the debt, the Company was required to pay a "make-whole payment" of $26.3 million to the lenders. The $26.3 million (plus $0.9 million of unamortized debt costs) is included in the consolidated statement of operations for the year ended December 31, 1998 as "Extraordinary item--early extinguishment of debt."

7. CAPITAL STRUCTURE

Second Amended and Restated Agreement of Limited Partnership of the Company. 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 Unitholders, 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 the Company to issue an unlimited number of additional limited partner interests and other equity securities of the Company 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 the Unitholders. During the Subordination Period, however, the Company is limited with regards to the number of equity securities that it 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 Common Units issued in connection with the TNGL acquisition, the number of Common Units available (and unreserved) to the Company for general partnership purposes during the Subordination Period is currently 27,275,000.

Subordinated Units. The 21,409,872 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 the Company has 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 (or 10,704,936 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 (or 5,352,468 Subordinated Units) would convert into Common Units is April 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 April 1, 2003. The remaining 10,704,936 Subordinated Units would convert into Common Units on July 1, 2003 should the balance of the conversion requirements be met.

Special Units. The Special Units issued to Shell do not accrue distributions and are not entitled to cash distributions until their conversion into Common Units. 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. On August 1, 2000, 1.0 million of the original issue of 14.5 million Special Units converted into Common Units. The remaining 13.5 million Special Units of the original issue will automatically convert into Common Units as follows: 5.0 million Units on August 1, 2001 and 8.5 million Units on August 1, 2002.

On June 28, 2000, Shell met certain year 2000 performance criteria for the issuance of 3.0 million non-distribution bearing, convertible Contingency Units (referred to as the "second issue" of Special Units). Per an agreement with Shell, the Company issued these Special Units on August 1, 2000. Shell has the opportunity to earn an additional 3.0 million non-distribution bearing, convertible Contingency Units (i.e., a "third issue" of Special Units) based on certain performance criteria for calendar year 2001. Specifically, Shell will earn the third issue of Special Units if at any point during calendar year 2001 (or extensions thereto due to force majeure events) gas production by Shell from its offshore Gulf of Mexico producing properties and leases is 900 million cubic feet per day for 180 not-necessarily-consecutive days or 350 billion cubic feet on a cumulative basis. If the year 2001 performance test is not met but Shell's offshore Gulf of Mexico gas production reaches 725 billion cubic feet on a cumulative basis in calendar years 2000 and 2001 (or extensions thereto due to force majeure events), Shell would still earn the third issue of Special Units. If both the second and third issues of Special Units are earned, 1.0 million of these Special Units would convert into Common Units on August 1, 2002 and 5.0 million of these Special Units would convert into Common Units on August 1, 2003. Special Units issued to Shell as part of these contingent agreements do not accrue distributions and are not entitled to cash distributions until conversion into Common Units. With regards to income and depreciation allocation from either a financial accounting or tax basis, these Special Units will be treated identically to the 14.5 million Special Units originally issued.

Under the rules of the New York Stock Exchange, the conversion feature of the Special Units into Common Units requires approval of the Company's Unitholders. With respect to the August 2000 conversion, EPC Partners II, Inc. ("EPC II"), which owns in excess of 81% of the outstanding Common Units, voted its Units in favor of conversion, which provided the necessary votes for approval.

Units Acquired by Trust. During the first quarter of 1999, the Company established a revocable grantor trust (the "Trust") to fund future liabilities of a long-term incentive plan. At December 31, 2000, the Trust had purchased a total of 267,200 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 will receive distributions; however, they are excluded from the calculation of net income per Unit.

On May 12, 2000, the Company filed a Registration Statement with the Securities and Exchange Commission for the transfer of up to (i) 1,000,000 Common Units to fund a long-term incentive plan established by the General Partner and (ii) 1,000,000 Common Units to fund a long-term incentive plan established by Enterprise Products Company.

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

	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	
Common Units purchased by consolidated Trust				(267,200)
Balance, December 31, 1999	45,552,915	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	46,524,515	21,409,870	16,500,000	(267,200)

8. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-averaged 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 shares used in the calculation of basic earnings per Unit and diluted earnings per Unit for the three years ended December 31, 2000.

	For Year Ended December 31,		
	2000	1999	1998
Income before extraordinary item and minority interest	$ 222,759	$ 121,521	$ 37,355
General partner interest	(2,597)	(1,203)	(101)
Income before extraordinary item and minority interest available to Limited Partners	220,162	120,318	37,254
Extraordinary charge on early extinguishment of debt			(27,176)
Minority interest	(2,253)	(1,226)	(102)
Net income available to Limited Partners	$ 217,909	$ 119,092	$ 9,976
BASIC EARNINGS PER UNIT			
Numerator			
Income before extraordinary item and minority interest available to Limited Partners	$ 220,162	$ 120,318	$ 37,254
Extraordinary charge on early extinguishment of debt			$ (27,176)
Net income available to Limited Partners	$ 217,909	$ 119,092	$ 9,976
Denominator			
Weighted-average Common Units outstanding	45,698	45,300	38,714
Weighted-average Subordinated Units outstanding	21,410	21,410	21,410
Total	67,108	66,710	60,124
Basic Earnings per Unit			
Income before extraordinary item and minority interest available to Limited Partners	$ 3.28	$ 1.80	$ 0.62
Extraordinary charge on early extinguishment of debt			$ (0.45)
Net income available to Limited Partners	$ 3.25	$ 1.79	$ 0.17
DILUTED EARNINGS PER UNIT			
Numerator			
Income before extraordinary item and minority interest available to Limited Partners	$ 220,162	$ 120,318	$ 37,254
Extraordinary charge on early extinguishment of debt			$ (27,176)
Net income available to Limited Partners	$ 217,909	$ 119,092	$ 9,976
Denominator			
Weighted-average Common Units outstanding	45,698	45,300	38,714
Weighted-average Subordinated Units outstanding	21,410	21,410	21,410
Weighted-average Special Units outstanding	15,336	6,078	-
Total	82,444	72,788	60,124
Basic Earnings per Unit			
Income before extraordinary item and minority interest available to Limited Partners	$ 2.67	$ 1.65	$ 0.62
Extraordinary charge on early extinguishment of debt			$ (0.45)
Net income available to Limited Partners	$ 2.64	$ 1.64	$ 0.17

The weighted-average impact of the issuance of the second issue of Special Units (formerly Contingency Units, as described under the "Special Units" section in Note 7) are included in the diluted earnings per Unit calculation for fiscal

2000 (beginning August 1, 2000, the effective date of the contingent agreement between Shell and the Company). The Contingency Units relating to the third issue of Special Units to be issued upon achieving certain performance criteria in future periods have been excluded from diluted earnings per Unit because such tests have not been met at December 31, 2000.

9. DISTRIBUTIONS

The Company intends, 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. The Company made incentive cash distributions to the General Partner of $0.4 million during 2000 and none in prior periods.

On January 17, 2000, the Company declared an increase in its quarterly cash distribution to $0.50 per Unit. This amount was subsequently raised to $0.525 per Unit on July 17, 2000 and $.550 per Unit on December 7, 2000.

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

		Cash Distributions			
		Per Common Unit	Per Subordinated Unit	Record Date	Payment Date
1999	First Quarter	$ 0.450	$ 0.450	Jan. 29, 1999	Feb. 11, 1999
	Second Quarter	$ 0.450	$ 0.070	Apr. 30, 1999	May 12, 1999
	Third Quarter	$ 0.450	$ 0.370	Jul. 30, 1999	Aug. 11, 1999
	Fourth Quarter	$ 0.450	$ 0.450	Oct. 29, 1999	Nov. 10, 1999
2000	First Quarter	$ 0.500	$ 0.500	Jan. 31, 2000	Feb. 10, 2000
	Second Quarter	$ 0.500	$ 0.500	Apr. 28, 2000	May 10, 2000
	Third Quarter	$ 0.525	$ 0.525	Jul. 31, 2000	Aug. 10, 2000
	Fourth Quarter	$ 0.525	$ 0.525	Oct. 31, 2000	Nov. 10, 2000
2001	First Quarter (through February 28, 2001)	$ 0.550	$ 0.550	Jan. 31, 2001	Feb. 9, 2001

10. RELATED PARTY TRANSACTIONS

The Company has no employees. All management, administrative and operating functions are performed by employees of EPCO pursuant to the EPCO Agreement entered into by EPCO, the General Partner and the Company in July 1998.

Under the terms of the EPCO agreement, EPCO agreed to (i) manage the business and affairs of the Company; (ii) employ the operating personnel involved in the Company's business for which EPCO is reimbursed by the Company at cost (based upon EPCO's actual salary costs and related fringe benefits); (iii) allow the Company 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; (iv) grant an irrevocable, non-exclusive worldwide license to all of the trademarks and trade names used in its business to the Company; (v) indemnify the Company against any losses resulting from certain lawsuits; and (vi) 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 the Company for $1 per year and assigned its purchase options under such leases to the Company. EPCO is liable for the lease payments associated with these assets. Operating costs and expenses (as shown on the audited Statements of Consolidated Operations) include charges for EPCO's employees who operate the Company's various facilities.

Pursuant to the EPCO Agreement, the charges for EPCO's employees who manage the business and affairs of the Company are reimbursed only under certain circumstances. SG&A charges to EPCO resulting from the hiring of additional management personnel and other costs associated with the expansion and business development activities of the Company (through the construction of new facilities or the completion of acquisitions) are reimbursed by the Company.

In lieu of reimbursement for all other SG&A costs incurred by EPCO, EPCO is entitled to receive an annual Administrative Services Fee (the "EPCO Fees", initially set at $12.0 million). The General Partner, with the approval and consent of the Audit and Conflicts Committee, may agree to increases in the EPCO Fees of up to 10% each contract year (defined as August 1 to July 31) during the 10-year term of the EPCO Agreement. Since the initial contract year ending July 31, 1999, the Audit and Conflicts Committee has approved two increases in the EPCO Fees. The annual fee was increased to $13.2 million for the second contract year and subsequently raised to $14.5 million for the third contract year.

EPCO also operates most of the plants owned by the unconsolidated affiliates and charges them for actual salary costs and related fringe benefits. In addition, EPCO charged the unconsolidated affiliates for management services provided; such charges aggregated $0.9 million for 2000, $0.8 million for 1999 and $1.7 million for 1998. Since EPCO pays the rental charges for the Retained Leases, such payments are considered a contribution by EPCO for the benefit of each partnership interest and are included as such in Partners' Equity, and a corresponding charge for the rental expense is included in the consolidated statements of operations. Rental expense, included in operating costs and expenses, for the Retained Leases was $10.6 million for both 2000 and 1999 and $11.3 million for 1998 (of which $4.0 million occurred after the public offering).

The Company also has transactions in the normal course of business with the unconsolidated affiliates and other subsidiaries and divisions of EPCO. Such transactions include the buying and selling of NGL products, loading of NGL products, transportation of NGL products by truck and plant support services.

As a result of the TNGL acquisition, Shell acquired an ownership interest in the Company and its General Partner. At December 31, 2000, Shell owned approximately 20.5% of the Company and 30% of the General Partner. Shell is a significant customer of the gas processing assets. Under the terms of the Shell Processing Agreement, the Company has the right to process substantially all of Shell's current and future natural gas production from the Gulf of Mexico. This includes natural gas production from the developments currently referred to as deepwater. Generally, the Shell Processing Agreement grants the Company 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 raw make extracted by the Company's gas processing facilities from Shell's natural gas production from such leases; with the obligation to deliver to Shell the natural gas stream after the raw make is extracted. Generally, the Company's revenues from Shell are derived from the sale of NGL and petrochemical products with its operating costs and expenses from Shell primarily due to the purchase of natural gas. The Company has an extensive and ongoing relationship with Shell as a customer, vendor and limited partner.

The following table shows the related party amounts by major income statement category for the last three years:

	For the Years Ended December 31,		
	2000	1999	1998
Revenues from consolidated operations			
Unconsolidated affiliates	$ 61,988	$ 40,352	$ 36,474
Shell	292,741	56,301	
EPCO and subsidiaries	4,750	9,148	19,531
Operating costs and expenses			
Unconsolidated affiliates	58,202	20,696	9,270
Shell	736,655	188,570	
EPCO and subsidiaries	9,492	35,046	9,997
Selling, general and administrative expenses			
Base fees payable under EPCO Agreement	13,750	12,500	5,129

11. COMMITMENTS AND CONTINGENCIES

Redelivery Commitments

From time to time, the Company stores NGL products for third parties under various processing and similar agreements. Under the terms of these agreements, the Company is generally required to redeliver to the owner its NGL products upon demand. The Company is insured for any physical loss of such NGL products due to catastrophic events. At December 31, 2000, NGL products aggregating 235 million gallons were due to be redelivered to the owners.

Lease Commitments

The Company leases 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, 2000 are as follows:

2001	$ 7,228
2002	5,048
2003	4,797
2004	4,260
2005	214
Thereafter	1,225
Total minimum obligations	$ 22,772

Lease expense charged to operations (including Retained Leases) for the years ended December 31, 2000, 1999 and 1998 was approximately $18.3 million , $20.2 million and $18.5 million, respectively.

Gas Purchase Commitments

The Company has annual renewable gas purchase contracts with four suppliers. As of December 31, 2000, the Company is required to make daily purchases as follows:

- 5,000 million British Thermal Units ("MMBtu") per day through February 28, 2001,
- 13,000 MMBtu per day through March 31, 2001,
- 5,000 MMBtu per day through July 31, 2001,
- 5,000 MMBtu per day through September 30, 2001, and
- 5,000 MMBtu per day through October 31, 2001.

The cost of these natural gas purchase commitments approximate market value at the time of delivery.

Capital Expenditure Commitments

As of December 31, 2000, the Company had capital expenditure commitments totaling approximately $10.9 million, of which $0.8 million relates to the construction of projects of unconsolidated affiliates.

Litigation

EPCO has indemnified the Company against any litigation pending as of the date of its formation. The Company is sometimes named as a defendant in litigation relating to its normal business operations. Although the Company insures itself 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 the Company against liabilities arising from future legal proceedings as a result of its ordinary business activity. Except as note below, management is aware of no significant litigation, pending or threatened, that would have a significantly adverse effect on the Company's financial position or results of operations.

The operations of the Company 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 the operations of the pipelines, processing and storage facilities. For example, the Mont Belvieu processing and storage facility is 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 in the country in this "severe" category. One of the other consequences of this non-attainment status is the potential imposition of lower limits on the emissions of certain pollutants, particularly oxides of nitrogen which are produced through combustion, as in the gas turbines at the Mont Belvieu processing facility. Regulations imposing more strict requirements on existing facilities were issued in December, 2000. These regulations mandate 90% reductions in oxides of nitrogen emissions from point sources such as the gas turbines at the Company's Mont Belvieu processing facility. The technical practicality and economic reasonableness of requiring existing gas turbines to achieve such reductions, as well as the substantive basis for setting the 90% reduction requirements, have been challenged under state law in litigation filed in the District Court of Travis County, Texas, on January 19, 2001, by the Company as part of a coalition of major Houston-Galveston area industries. In addition to the Company, the plaintiffs in this case are the BCCA Appeal Group, Equistar Chemicals, LP, Lyondell Chemical Company, Lyondell-CITGO Refining L.P. and Reliant Energy, Incorporated; named as defendants are the Texas Natural Resource Conservation Commission and its chairman, commissioners and executive director. The suit seeks a ruling that these regulations are invalid and void and asks for a temporary injunction to stay their effectiveness pending final judgment in the case. If these regulations stand as issued, they would require substantial redesign and modification of the Mont Belvieu facilities to achieve the mandated reductions; however, the precise impact of these requirements on the Company's operations cannot be determined until this litigation is resolved.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following disclosure of estimated fair value was determined by the Company, using available market information and appropriate valuation methodologies. Considerable judgment, however, is necessary to interpret market data and develop the related estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that the Company could realize upon disposition of the financial instruments. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

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 fair value of the Company's fixed-rate long term debt is estimated based on the quoted market prices for debt of similar terms and maturities. No variable rate long-term debt was outstanding at year end.

Interest Rate Swaps. The Company's interest rate exposure results from variable-rate borrowings from commercial banks and fixed-rate borrowings pursuant to the $350 Million Senior Notes and the $54 Million MBFC Loan. The Company manages its exposure to changes in interest rates in its debt portfolio by utilizing interest rate swaps. 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.

In March 2000, after the issuance of the $350 Million Senior Notes and the execution of the $54 Million MBFC Loan, 100% of the Company's consolidated debt were fixed-rate obligations. To maintain a balance between variable-rate and fixed-rate exposure, the Company entered into interest rate swap agreements with a notional amount of $154 million by which the Company receives payments based on a fixed-rate and pays an amount based on a floating-rate. At December 31, 2000, the Company's consolidated debt portfolio interest rate exposure was 62 percent fixed and 38 percent floating, after considering the effect of the interest rate swap agreements. The notional amount does not represent exposure to credit loss. The Company monitors its positions and the credit ratings of its counterparties. Management believes the risk of incurring a credit related loss is remote, and that if incurred, such losses would be immaterial.

Cash flows related to interest rate swap agreements are classified as "Operating activities cash flows" in the Statements of Consolidated Cash Flows. The net cash differentials paid or received on interest rate swap agreements are accrued and recognized as adjustments to interest expense. The effect of these swaps (none of which are leveraged) was to decrease the Company's interest expense by $1.2 million during 2000. Following is selected information on the Company's portfolio of interest rate swaps at December 31, 2000:

Interest Rate Swap Portfolio at December 31, 2000 (1) :
(Dollars in millions)

Notional Amount	Period Covered	Early Termination Date (2)	Fixed / Floating Rate (3)
$ 50.0	March 2000 - March 2005	March 2001	8.25% / 7.3100%
$ 50.0	March 2000 - March 2005	March 2001 (4)	8.25% / 7.3150%
$ 54.0	March 2000 - March 2010	March 2003	8.70% / 7.6575%

Notes to Interest Rate Swap table:

(1) All swaps outstanding at December 31, 2000 were entered into for the purpose of managing a portion of financing costs associated with its fixed-rate debt.
(2) In each case, the counterparty has the option to terminate the interest rate swap on the Early Termination Date.
(3) In each case, the Company is the floating-rate payor. The floating rate was the rate in effect as of December 31, 2000.
(4) Swap was terminated by the bank effective March 15, 2001.

The $2.0 million fair value of interest rate swap agreements at December 31, 2000 is based on market rates and the early termination option being exercised. The fair value represents the estimated amount the Company would receive or pay based on current interest rates.

Commodity-related transactions. The Company enters into swaps and other contracts to hedge the price risks associated with inventories, commitments and certain anticipated transactions. The swaps and other contracts are with established energy companies and major financial institutions. The Company believes its credit risk is minimal on these transactions, as the counterparties are required to meet stringent credit standards. There is continuous day-to-day involvement by senior management in the hedging decisions, operating under resolutions adopted by the Board of Directors of the General Partner.

At December 31, 1999, the Company had open positions covering 24.0 billion cubic feet of natural gas extending into December 2000 related to the swaps described above. The fair value of these financial instruments at December 31, 1999 was estimated at $0.5 million payable by the Company. At December 31, 2000, the Company had open commodity positions covering 28.8 billion cubic feet of natural gas and 1.2 million barrels of NGL futures, primarily propane, extending into December 2001. The fair value of these financial instruments at December 31, 2000 was estimated at $38.6 million payable by the Company. The fair value estimates at December 31, 2000 and 1999 are based on quoted market prices of comparable contracts and approximate the gain or loss that would have been realized if the contracts had been settled at the balance sheet date. To the extent that the hedged positions are effective, gains or losses on these derivative commodity instruments would be offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table below.

The following table summarizes the estimated fair values of the Company's financial instruments at December 31, 2000 and 1999:

	2000		1999	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets:				
Cash and cash equivalents	$ 60,409	$ 60,409	$ 5,230	$ 5,230
Accounts receivable	415,618	415,618	318,423	318,423
Accounts payable and accrued expenses	551,620	551,620	383,944	383,944
Financial liabilities:				
Variable-rate debt	-	-	295,000	295,000
Fixed-rate debt	404,000	423,836	n/a	n/a
Commodity futures	725	705	n/a	n/a
Off-balance sheet instruments:				
Interest rate swaps receivable	2,030	2,030	n/a	n/a
Commodity futures payable	40,020	39,266	539	539

Recent Accounting Developments

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities, as amended and interpreted. SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. All derivatives, whether designated in hedging relationships or not, will be required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, the changes in fair value of the derivative and the hedged item will be recognized in earnings. If the derivative is designated as a cash flow hedge, changes in the fair value of the derivative will be recorded as a component of Partners' Equity entitled Other Comprehensive Income (to the extent the hedge is effective) and will be recognized in the income statement when the hedged item affects earnings. The ineffective portion of the hedge is required to be recorded in earnings. SFAS 133 defines new requirements for designation and documentation of hedging relationships as well as ongoing effectiveness assessments in order to use hedge accounting. A derivative that does not qualify as a hedge will be recorded at fair value through earnings.

The Company expects that at January 1, 2001, it will record a $ 42.2 million loss in Other Comprehensive Income as a cumulative transition adjustment for derivatives (commodity contracts) designated in cash flow-type hedges prior to adopting SFAS 133. In addition, the Company expects to record a $2.1 million derivative asset and a corresponding increase to its long term debt relating to derivatives (interest rate swaps) designated in fair-value-type hedges prior to adopting SFAS 133. The fair value hedges will have no impact to earnings upon transition.

The Company will reclassify from Other Comprehensive Income $21.7 million as a charge to earnings during the first quarter of 2001 and $20.5 million as a charge to earnings during the remainder of 2001. The actual gain or loss amount to be recognized in earnings related to these commodity contracts over time is dependent upon the final settlement price associated with the commodity prices.

13. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

	Year Ended December 31,		
	2000	1999	1998
(Increase) decrease in:			
Accounts receivable	$ (93,716)	$ (152,363)	$ 3,699
Inventories	(21,452)	7,471	1,361
Prepaid and other current assets	2,316	(7,523)	(342)
Intangible assets	(5,226)		
Other assets	(1,527)	1,164	1,781
Increase (decrease) in:			
Accounts payable	18,723	(6,276)	(40,005)
Accrued gas payable	143,457	206,178	(19,463)
Accrued expenses	4,978	(27,788)	(120)
Other current liabilities	15,283	6,747	(10,082)
Other liabilities	8,122	296	
Net effect of changes in operating accounts	$ 70,958	$ 27,906	$ (63,171)
Cash payments for interest, net of $3,277, $153 and $180 capitalized in 2000, 1999 and 1998, respectively	$ 17,774	$ 15,780	$ 6,971

Capital expenditures for 2000 were $243.9 million compared to $21.2 million for the same period in 1999. Capital expenditures in 2000 included $99.5 million for the purchase of the Lou-Tex Propylene Pipeline and related assets and $83.7 million in construction costs for the Lou-Tex NGL Pipeline.

During 2000, the Company increased the gas processing contract by $25.2 million for non-cash purchase accounting adjustments relating to the TNGL acquisition. The offset to such adjustment was various working capital accounts.

On August 1, 1999, the Company paid $166 million in cash and issued 14.5 million non-distribution bearing, convertible Special Units to Shell in connection with the TNGL acquisition. The value of the 14.5 million Special Units was $210.4 million at time of issuance. On August 1, 2000, the Company issued an additional 3.0 million non-distribution bearing, convertible Special Units to Shell. The value of these new Special Units was $55.2 million at time of issuance. In both cases, the value of the Special Units at the time of issuance was recorded as a non-cash contribution by Shell to the Company. The General Partner made non-cash contributions to the Company relating to the TNGL acquisition of $2.1 million in 1999 and $0.6 million in 2000. See Note 7 for a discussion of the Special Units and the performance tests.

On July 1, 1999, the Company paid approximately $42 million in cash to Kinder Morgan and EPCO and assumed approximately $4 million of debt in connection with the acquisition of an additional interest in MBA.

During 1998, the Company contributed $1.9 million (at net book value) of plant equipment to an unconsolidated affiliate as part of its investment therein.

14. CONCENTRATION OF CREDIT RISK

A substantial portion of the Company's revenues are derived from natural gas processing and the fractionation, isomerization, propylene production, marketing, storage and transportation of NGLs to various companies in the NGL industry, located in the United States. Although this concentration could affect the Company's overall exposure to credit risk since these customers might be affected by similar economic or other conditions, management believes the Company is exposed to minimal credit risk, since the majority of its business is conducted with major companies within the industry and much of the business is conducted with companies with which the Company has joint operations. The Company generally does not require collateral for its accounts receivable.

The Company is subject to a number of risks inherent in the industry in which it operates, primarily fluctuating gas and liquids prices and gas supply. The Company's financial condition and results of operations 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 and a variety of additional factors that are beyond the control of the Company. In addition, the Company must continually connect new wells through third-party gathering systems which serve the gas plants in order to maintain or increase throughput levels to offset natural declines in dedicated volumes. The number of wells drilled by third parties 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 the Company's control.

15. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available that is evaluated regularly 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.

The Company has five reportable operating segments: Fractionation, Pipeline, 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 includes NGL fractionation, butane isomerization (converting normal butane into high purity isobutane) and polymer grade propylene fractionation services. Pipeline consists of pipeline, storage and import/export terminal services. Processing includes the natural gas processing business and its related NGL merchant activities. Octane Enhancement represents the Company's 33.33% ownership interest in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE). The Other operating segment consists of fee-based marketing services and other plant support functions.

The Company evaluates segment performance on the basis of 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. The Company's equity earnings from unconsolidated affiliates are included in segment gross operating margin.

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					Adjustments and Eliminations	Consolidated Totals
	Fractionation	Pipelines	Processing	Octane Enhancement	Other		
Revenues from external customers							
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
1998	213,966	18,306	506,630				738,902
Intersegment revenues							
2000	$ 177,963	$ 55,690	$ 630,155		$ 375	$ (864,183)	
1999	118,103	43,688	216,720		444	(378,955)	
1998	162,379	37,574	90		383	(200,426)	
Equity income in unconsolidated affiliates							
2000	$ 6,391	$ 7,321		$ 10,407			$ 24,119
1999	1,566	3,728		8,183			13,477
1998	5,122	748		9,801			15,671
Total revenues							
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
1998	381,467	56,628	506,720	9,801	383	(200,426)	754,573
Gross operating margin by segment							
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
1998	66,627	27,334	(652)	9,801	(3,483)		99,627
Segment property, net							
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							
2000	$ 105,194	$ 102,083	$ 33,000	$ 58,677			$ 298,954
1999	99,110	85,492	33,000	63,004			280,606

One Fractionation third-party customer in 1998 provided more than 10% of consolidated revenues. No single third-party customer provided more than 10% of consolidated revenues in 2000 or 1999.

All consolidated revenues were earned in the United States. The operations of the Company are centered along the Texas, Louisiana and Mississippi Gulf Coast areas.

Certain reclassifications have been made to the 1999 and 1998 amounts to conform to the 2000 presentation. Gross operating margin for both the Fractionation and Pipeline segments in 1999 was increased by $4.1 million each due to a reclassification of margins for the Tebone and Venice NGL fractionation and pipeline assets from the Processing segment. Revenues from external customers for both 1998 and 1999 was adjusted to reflect (i) the reclassification of equity income in unconsolidated affiliates to a separate line item in the above table and (ii) the reclassification of certain revenue items that had previously been classified as adjustments to consolidated revenues to the segments to which they relate. The effect of the reclassification of amounts in item (ii) above was to reduce revenues from external customers for Fractionation by $30.7 million in 1999 and $54.7 million in 1998 and Pipelines by $5.1 million in 1999 and $0.3 million in 1998.

The Venice NGL fractionation and pipeline assets are part of the Company's investment in VESCO which is classified under the Processing segment. The Company views both Tebone and Venice pipeline assets as an integral part of its Louisiana Pipeline System.

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

	For the Year Ended December 31,		
	2000	1999	1998
Gross Operating Margin by segment:			
Fractionation	$ 129,376	$ 110,424	$ 66,627
Pipeline	56,099	31,195	27,334
Processing	122,240	28,485	(652)
Octane enhancement	10,407	8,183	9,801
Other	2,493	908	(3,483)
Gross Operating Margin total	320,615	179,195	99,627
Depreciation and amortization	35,621	23,664	18,579
Retained lease expense, net	10,645	10,557	12,635
Loss (gain) on sale of assets	2,270	123	(276)
Selling, general and administrative expenses	28,345	12,500	18,216
Consolidated operating income	$ 243,734	$ 132,351	$ 50,473

16. SUBSEQUENT EVENTS (UNAUDITED)

Manta Ray, Nautilus and Nemo Pipeline Systems

On January 29, 2001, the Company acquired ownership interests in three natural gas pipeline systems and related equipment located offshore Louisiana in the Gulf of Mexico from affiliates of El Paso Energy Corp. for $88.1 million in cash. These systems total approximately 362 miles of pipeline. The Company acquired a 25.67% interest in each of the Manta Ray and Nautilus pipeline systems and a 33.92% interest in the Nemo pipeline system. Affiliates of Shell own an interest in all three systems, and an affiliate of Marathon Oil Company owns an interest in the Manta Ray and Nautilus systems. The Manta Ray system comprises approximately 237 miles of pipeline with a capacity of 750 million cubic fee ("MMcf") per day and related equipment, the Nautilus system comprises approximately 101 miles of pipeline with a capacity of 600 MMcf per day, and the Nemo system, when completed in the fourth quarter of 2001, will comprise approximately 24 miles of pipeline with a capacity of 300 MMcf per day.

Stingray Pipeline System and Related Facilities

On January 29, 2001, the Company and an affiliate of Shell acquired, through a 50/50 owned entity, the Stingray natural gas pipeline system and related facilities from an affiliate of El Paso for $50.2 million in cash. The Stingray system comprises approximately 375 miles of pipeline with a capacity of 1.2

billion cubic feet ("Bcf") per day offshore Louisiana in the Gulf of Mexico. Shell will be responsible for the commercial and physical operations of the Stingray system.

$450 Million Senior Notes

On January 24, 2001, the Company 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 "$450 Million Senior Notes"). The Company received proceeds, net of underwriting discounts and commissions, of approximately $446.8 million. The proceeds from this offering were or will be used to acquire the Acadian and EPE natural gas pipeline systems for $339.2 million and to finance the cost to construct certain NGL pipelines and related projects and for working capital and other general partnership purposes.

February 2001 Registration Statement

On February 23, 2001, the Company filed a $500 million universal shelf registration (the "February 2001 Registration Statement") covering the issuance of an unspecified amount of equity or debt securities or a combination thereof. The Company expects 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 the Company's funding requirements and the availability of alternative funding sources. The Company routinely reviews acquisition opportunities.

17. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 1999:				
Revenues	$ 148,877	$ 177,479	$ 445,028	$ 575,072
Operating income	12,068	21,069	40,070	59,144
Income before minority interest	10,561	19,350	36,716	54,894
Minority interest	(106)	(196)	(370)	(554)
Net income	10,455	19,154	36,346	54,340
Net income per Unit, basic	$ 0.16	$ 0.28	$ 0.54	$ 0.81
Net income per Unit, diluted	$ 0.16	$ 0.28	$ 0.47	$ 0.66
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

As a result of the TNGL and MBA acquisitions, the Company's earnings increased significantly in the third quarter of 1999 over the second quarter of 1999. The TNGL acquisition was effective August 1, 1999 and the MBA acquisition as effective July 1, 1999.

Enterprise Products Partners L.P. SCHEDULE II

Valuation and Qualifying Accounts

(amounts in millions of dollars)

	Year Ended December 31,		
	1998	1999	2000
Accounts Receivable - trade			
Allowance for doubtful accounts (a)			
Balance at beginning of period			$ 15.9
Reserve increases charged to earnings		$ 3.0	
Reserve increases charged to other balance sheet accounts		12.9	
Amounts charged against reserve (deductions)			(5.0)
Balance at end of period		$ 15.9	$ 10.9
Other current liabilities			
Reserve for inventory losses (b)			
Balance at beginning of period	$ 0.8	$ 0.8	$ 2.9
Reserve increases charged to earnings	10.0	7.3	5.1
Reserve increases charged to other balance sheet accounts			
Amounts charged against reserve (deductions)	(10.0)	(5.2)	(2.3)
Balance at end of period	$ 0.8	$ 2.9	$ 5.7

(a) As a result of the TNGL acquisition in 1999, the Company acquired a $12.9 million allowance for doubtful accounts. Historically, the Company did not experience any significant losses from bad debts and therefore did not require an allowance account.

(b) Generally denotes net underground NGL storage well product losses.

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 22, 2001.

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 22, 2001.

Signature	Title
/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 L. Duncan Randa L. Duncan	Director
/s/ Richard H. Bachmann Richard H. Bachmann	Executive Vice President, Chief Legal Officer, Secretary and Director
/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 12.1

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

	For the Year Ended December 31,				
	2000	1999	1998	1997	1996
Income (loss) before minority interest and equity investments	$198.6	$108.0	$ (5.5)	$ 37.0	$ 45.7
Add:					
Fixed charges	42.6	23.3	21.5	37.6	36.7
Amortization of capitalized interest	0.2	0.1	0.1	0.1	0.1
Distributed income of equity investees	37.3	6.0	9.1	7.3	7.2
Less:					
Capitalized interest	(3.3)	(0.2)	(0.2)	(2.0)	(1.6)
Minority interest	(2.3)	(1.2)	(0.1)	(0.5)	(0.6)
Total Earnings	$273.1	$136.0	$ 24.9	$ 79.5	$ 87.5
Fixed charges:					
Interest expense	33.3	16.4	15.1	25.7	26.3
Capitalized interest	3.3	0.2	0.2	2.0	1.6
Interest portion of rental expense	6.0	6.7	6.2	9.9	8.8
Total	$ 42.6	$ 23.3	$ 21.5	$ 37.6	$ 36.7
Ratio of Earnings to Fixed charges	6.41x	5.84x	1.16x	2.11x	2.38x

These computations include the Company and its subsidiaries, and 50% or less equity companies. For these ratios, "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
- the Company's 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
Sorrento Pipeline Company, LLC, a Texas limited liability company
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
Entell NGL Services, LLC, a Delaware limited liability company
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
EPOLP 1999 Grantor Trust

EXHIBIT 23.1

INDEPENDENT AUDITOR'S CONSENT

We consent to the incorporation by reference in Enterprise Products Partners L.P.'s and Enterprise Products Operating L.P.'s Post-Effective Amendment No. 1 to Registration Statement No. 333-36856 of Enterprise Products Partners L.P. on Form S-8 of our report dated February 28, 2001, appearing in the Annual Report on Form 10-K of Enterprise Products Partners L.P. for the year ended December 31, 2000.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 22, 2001