FORM 10-Q

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

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

For the quarterly period ended September 30, 2001

OR

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

For the transition period from _______ to _______

Commission file number: 1-14323

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

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

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

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 ___

The registrant had 51,055,715 Common Units outstanding as of November 13, 2001.

Enterprise Products Partners L.P. and Subsidiaries

TABLE OF CONTENTS

Glossary

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

Acadian Gas	Acadian Gas, LLC
BBtu/d	Billion British thermal units per day, a measure of heating value
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BPD	Barrels per day
Btu	British thermal unit, a measure of heating value
Company	Enterprise Products Partners L.P. and subsidiaries
EPCO	Enterprise Products Company, an affiliate of the Company
EPE	El Paso Corporation, its subsidiaries and affiliates
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
General Partner	Enterprise Products GP, LLC, the general partner of the Company and Operating Partnership
Manta Ray	A Gulf of Mexico offshore Louisiana natural gas pipeline system owned by Manta Ray Offshore Gathering Company, LLC
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
MLP	Denotes Enterprise Products Partners L.P. as guarantor of certain debt obligations of the Operating Partnership
MMBbls	Millions of barrels
MMBtus	Million British thermal units, a measure of heating value
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MTBE	Methyl tertiary butyl ether
Nautilus	A Gulf of Mexico offshore Louisiana natural gas pipeline system owned by Nautilus Pipeline Company, LLC
NGL or NGLs	Natural gas liquid(s)
NYSE	New York Stock Exchange
Operating Partnership	Enterprise Products Operating L.P. and subsidiaries
Operating Surplus	As defined within the Partnership Agreement
Partnership Agreement	Second Amended and Restated Agreement of Limited Partnership of the Company
PTR	Plant thermal reduction
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
Shell	Shell Oil Company, its subsidiaries and affiliates
Subordination Period	As defined within the Partnership Agreement
TNGL acquisition	Refers to the acquisition of Tejas Natural Gas Liquids, LLC from Shell effective August 1, 1999

PART 1. FINANCIAL INFORMATION.
Item 1. CONSOLIDATED FINANCIAL STATEMENTS.
Enterprise Products Partners L.P.
Consolidated Balance Sheets
(Dollar amounts in thousands)

ASSETS	September 30, 2001 (Unaudited)	December 31, 2000
Current Assets		
Cash and cash equivalents (includes restricted cash of $9,032 at September 30, 2001)	$ 67,076	$ 60,409
Accounts receivable - trade, net of allowance for doubtful accounts of $17,007 at September 30, 2001 and $10,916 at December 31, 2000	322,519	409,085
Accounts receivable - affiliates	16,184	6,533
Inventories	152,058	93,222
Prepaid and other current assets	68,109	12,107
Total current assets	625,946	581,356
Property, Plant and Equipment, Net	1,261,155	975,322
Investments in and Advances to Unconsolidated Affiliates	408,290	298,954
Intangible assets, net of accumulated amortization of $10,208 at September 30, 2001 and $5,374 at December 31, 2000	205,102	92,869
Other Assets	9,505	2,867
Total	$2,509,998	$1,951,368
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable - trade	$ 53,680	$ 96,559
Accounts payable - affiliate	33,135	56,447
Accrued gas payables	285,411	377,126
Accrued expenses	17,536	21,488
Other current liabilities	81,578	34,759
Total current liabilities	471,340	586,379
Long-Term Debt	855,443	403,847
Other Long-Term Liabilities	17,197	15,613
Minority Interest	11,887	9,570
Commitments and Contingencies		
Partners' Equity		
Common Units (51,055,715 Units outstanding at September 30, 2001 and 46,257,315 at December 31,2000)	664,287	514,896
Subordinated Units (21,409,870 Units outstanding at September 30, 2001 and December 31,2000)	198,387	165,253
Special Units (14,500,000 Units outstanding at September 30, 2001 and 16,500,000 at December 31,2000)	295,644	251,132
Treasury Units acquired by Trust, at cost (468,800 Common Units outstanding at September 30,2001 and 267,200 at December 31,2000)	(13,566)	(4,727)
General Partner	11,700	9,405
Accumulated other comprehensive income	(2,321)	
Total Partners' Equity	1,154,131	935,959

Total	$2,509,998	$ 1,951,368

See Notes to Unaudited Consolidated Financial Statements

Enterprise Products Partners L.P.
Statements of Consolidated Operations
(Unaudited)
(Dollar amounts in thousands, except per Unit amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	2000	2001	2000
REVENUES				
Revenues from consolidated operations	$723,329	$717,113	$2,519,041	$2,056,307
Equity income in unconsolidated affiliates	6,289	4,750	17,350	23,290
Total	729,618	721,863	2,536,391	2,079,597
COST AND EXPENSES				
Operating costs and expenses	634,496	659,021	2,263,876	1,878,233
Selling, general and administrative	7,716	6,978	21,621	20,020
Total	642,212	665,999	2,285,497	1,898,253
OPERATING INCOME	87,406	55,864	250,894	181,344
OTHER INCOME (EXPENSE)				
Interest expense	(12,610)	(7,486)	(35,928)	(23,330)
Interest income from unconsolidated affiliates		(88)	31	182
Dividend income from unconsolidated affiliates	392	2,241	2,024	6,236
Interest income - other	861	317	6,338	3,023
Other, net	(275)	(71)	(806)	(496)
Other income (expense)	(11,632)	(5,087)	(28,341)	(14,385)
INCOME BEFORE MINORITY INTEREST	75,774	50,777	222,553	166,959
MINORITY INTEREST	(767)	(514)	(2,245)	(1,689)
NET INCOME	$ 75,007	$ 50,263	$ 220,308	$ 165,270
ALLOCATION OF NET INCOME TO:				
Limited partners	$ 73,408	$ 49,566	$ 216,339	$ 163,423
General partner	$ 1,599	$ 697	$ 3,969	$ 1,847
BASIC EARNINGS PER UNIT				
Income before minority interest	$ 1.05	$ 0.74	$ 3.18	$ 2.47
Net income per Common and Subordinated unit	$ 1.04	$ 0.74	$ 3.15	$ 2.44
DILUTED EARNINGS PER UNIT				
Income before minority interest	$ 0.86	$ 0.60	$ 2.58	$ 2.02
Net income per Common, Subordinated and Special unit	$ 0.85	$ 0.60	$ 2.55	$ 2.00

See Notes to Unaudited Consolidated Financial Statements

Enterprise Products Partners L.P.
Statements of Consolidated Cash Flows
(Unaudited)
(Dollar amounts in Thousands)

	Nine Months Ended September 30,	
	2001	2000
OPERATING ACTIVITIES		
Net income	$ 220,308	$ 165,270
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:		
Depreciation and amortization	37,245	27,952
Equity in income of unconsolidated affiliates	(17,350)	(23,290)
Distributions received from unconsolidated affiliates	30,602	25,997
Leases paid by EPCO	7,900	7,904
Minority interest	2,245	1,689
Loss (gain) on sale of assets	(392)	2,276
Changes in fair market value of financial instruments (see Note 10)	(39,430)	
Net effect of changes in operating accounts	(116,362)	(27,001)
Operating activities cash flows	124,766	180,797
INVESTING ACTIVITIES		
Capital expenditures	(92,641)	(200,157)
Proceeds from sale of assets	567	85
Business acquisitions, net of cash received	(225,665)	
Collection of notes receivable from unconsolidated affiliates		6,519
Investments in and advances to unconsolidated affiliates	(119,865)	(2,307)
Investing activities cash flows	(437,604)	(195,860)
FINANCING ACTIVITIES		
Long-term debt borrowings	449,717	513,818

Long-term debt repayments		(355,000)
Debt issuance costs	(3,125)	(2,759)
Cash dividends paid to partners	(117,125)	(103,347)
Cash dividends paid to minority interest by Operating Partnership	(1,203)	(1,055)
Unit repurchases		(465)
Cash contributions from EPCO to minority interest	80	84
Units purchased by Trust	(8,839)	
Increase in restricted cash associated with commodity hedging activities	(9,032)	
Financing activities cash flows	310,473	51,276
NET CHANGE IN CASH AND CASH EQUIVALENTS	(2,365)	36,213
CASH AND CASH EQUIVALENTS, JANUARY 1	60,409	5,230
CASH AND CASH EQUIVALENTS, SEPTEMBER 30	$ 58,044	$ 41,443

See Notes to Unaudited Consolidated Financial Statements

Enterprise Products Partners L.P.
Statements of Consolidated Partners' Equity and Comprehensive Income
(Unaudited, dollar amounts in thousands)

	Partners' Equity			
	at September 30, 2001		at September 30, 2000	
	Units	Amount	Units	Amount
Limited Partners				
Balance, beginning of year	84,434	$ 931,280	81,463	$786,250
Net income		216,339		163,423
Leases paid by EPCO		7,820		7,825
Special Units issued to Shell in connection with contingency agreement	3,000	117,067	3,000	55,241
Units repurchased and retired in connection with buy-back program			(17)	(462)
Cash distributions		(114,188)		(102,118)
Balance, end of period	87,434	1,158,318	84,446	910,159
Treasury Units acquired by Trust				
Balance, beginning of year	(267)	(4,727)	(267)	(4,727)
Units purchased by Trust	(202)	(8,839)		
Balance, end of period	(469)	(13,566)	(267)	(4,727)
General Partner				
Balance, beginning of year		9,405		7,942
Net income		3,969		1,847
Leases paid by EPCO		80		79
Units repurchased and retired in connection with buy-back program				(3)
Cash contributions		1,183		557
Cash distributions		(2,937)		(1,228)
Balance, end of period		11,700		9,194
Accumulated Other Comprehensive Loss				
Balance, beginning of year				
Cumulative transition adjustment recorded on January 1, 2001 upon adoption of SFAS 133 (see Note 10)		(42,190)		
Reclassification of cumulative transition adjustment to earnings		39,869		
Balance, end of period		(2,321)		
Total Partners' Equity	86,965	$1,154,131	84,179	$914,626

	Comprehensive Income for Nine Months Ended	
	at September 30, 2001	at September 30, 2000
Net Income	$ 220,308	$165,270
Less: Accumulated Other Comprehensive Loss	(2,321)	
Comprehensive Income	$ 217,987	$165,270

See Notes to Unaudited Consolidated Financial Statements

Enterprise Products Partners L.P.
Notes to Unaudited Consolidated Financial Statements

1. GENERAL

In the opinion of Enterprise Products Partners L.P. (the "Company"), the accompanying unaudited consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for a fair presentation of the Company's consolidated financial position as of September 30, 2001, consolidated results of operations for the three and nine month periods ended September 30, 2001 and 2000, and cash flows, partners' equity and comprehensive income for the nine month periods ended September 30, 2001 and 2000. Although the Company believes the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission. These unaudited financial statements should be read in conjunction with the financial statements and notes thereto included in the Company's annual report on Form 10-K (File No. 1-14323) for the year ended December 31, 2000.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the accounting period. Actual results could differ from those estimates.

The results of operations for the three and nine month periods ended September 30, 2001 are not necessarily indicative of the results to be expected for the full year due to the effects of, among other things, (a) seasonal variations in NGL and natural gas prices, (b) timing of maintenance and other expenditures and (c) acquisitions of assets and other interests.

Certain reclassifications have been made to prior years' financial statements to conform to the presentation of the current period financial statements. These reclassifications do not affect historical net income of the Company.

Dollar amounts presented in the tabulations within the notes to the consolidated financial statements are stated in thousands of dollars, unless otherwise indicated.

2. 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 11.

At September 30, 2001, the Company's equity method investments (grouped by operating segment) included:

Fractionation segment:

- 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 excess cost is attributable to the fair market value of the plant assets). The unamortized balance of excess cost over the underlying equity in the net assets of Promix was $7.1 million at September 30, 2001.

Pipeline segment:

- 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.
- 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 41.67% interest in a NGL pipeline system located in south Louisiana.
- Dixie Pipeline Company ("Dixie") - an aggregate 19.9% interest in a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina. The Company's investment includes excess cost over the underlying equity in the net assets of Dixie of $37.4 million which is being amortized using the straight-line method over a period of 35 years (the excess cost is attributable to the fair market value of the pipeline assets). The unamortized balance of excess cost over the underlying equity in the net assets of Dixie was $36.0 million at September 30, 2001.
- Starfish Pipeline Company LLC ("Starfish") - a 50% interest in a natural gas gathering system and related dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana.
- Ocean Breeze Pipeline Company LLC ("Ocean Breeze") - a 25.67% interest in a limited liability company owning a 1% interest in the natural gas gathering and transmission systems owned by Manta Ray Offshore Gathering Company, LLC ("Manta Ray") and Nautilus Pipeline Company LLC ("Nautilus") located in the Gulf of Mexico offshore Louisiana.
- Neptune Pipeline Company LLC ("Neptune") - a 25.67% interest in a limited liability company owning a 99% interest in the Manta Ray and Nautilus natural gas gathering and transmission systems.
- Nemo Gathering Company, LLC ("Nemo") - a 33.92% interest in a natural gas gathering system located in the Gulf of Mexico offshore Louisiana that became operational in August 2001.
- Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp. (collectively, "Evangeline") - an approximate 49.5% aggregate interest in a natural gas pipeline system located in south Louisiana. The Company acquired its interests in these entities as a result of the Acadian Gas, LLC acquisition (see Note 3 for a description of this acquisition).

2001 Gulf of Mexico natural gas pipeline equity investments

The Company acquired its equity interests in Ocean Breeze, Neptune, Nemo and Starfish and their underlying investments on January 29, 2001 from EPE using proceeds from the issuance of the $450 Million Senior Notes (see Note 5 for discussion of long-term debt). The cash purchase price of the Ocean Breeze, Neptune and Nemo interests was $86.9 million with the purchase price of the Starfish interests being $25.1 million.

As a result of its investment in Ocean Breeze and Neptune, the Company acquired a 25.67% interest in each of the Manta Ray and Nautilus systems and a 33.92% interest in the Nemo 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 225 miles of pipeline with a capacity of 750 MMcf/d and related equipment, the Nautilus system comprises approximately 101 miles of pipeline with a capacity of 600 MMcf/d, and the Nemo system comprises approximately 24 miles of pipeline with a capacity of 300 MMcf/d. Shell is responsible for the commercial and physical operations of these pipeline systems.

The Company's investment in Ocean Breeze, Neptune and Nemo includes excess cost over the underlying equity in the net assets of these entities of $23.7 million which is being amortized using the straight-line method over a period of 35 years (the excess cost amounts are attributable to the fair market value of the pipeline assets). The unamortized balance of excess cost over the underlying equity in the net assets of Ocean Breeze, Neptune and Nemo was $23.1 million at September 30, 2001.

As a result of its investment in Starfish, the Company acquired a 50% interest in the Stingray system and a related onshore natural gas dehydration facility. The Company's sole partner in Starfish is an affiliate of Shell. The Stingray system comprises approximately 375 miles of pipeline with a capacity of 1.2 Bcf/d and

is located offshore Louisiana in the Gulf of Mexico. Shell is responsible for the commercial and physical operations of the Stingray system and related facilities.

Historical information for periods prior to January 1, 2001 do not reflect any impact associated with the

Company's equity investments in Ocean Breeze, Neptune, Nemo and Starfish. See Note 3 for combined pro forma impact of these investments on selected financial information of the Company.

Octane Enhancement segment:

o Belvieu Environmental Fuels ("BEF") - a 33.33% interest in a MTBE production facility located in southeast Texas. The production of MTBE is driven by oxygenated fuels programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation and as an additive to increase octane in motor gasoline. Any changes to these 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 have been well below levels of public health concern, there have been calls for the phase-out of MTBE in motor gasoline in various federal and state governmental agencies and advisory bodies.

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

At September 30, 2001, 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 company owning a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines in Louisiana. This investment is accounted for using the cost method under the Processing segment.

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

	September 30, 2001	December 31, 2000
Accounted for on equity basis:		
Fractionation:		
BRF	$ 29,664	$ 30,599
BRPC	19,069	25,925
Promix	45,497	48,670
Pipeline:		
EPIK	17,691	15,998
Wilprise	8,950	9,156
Tri-States	27,277	27,138
Belle Rose	11,655	11,653
Dixie	37,585	38,138
Starfish	25,875	
Ocean Breeze	967	
Neptune	75,046	
Nemo	11,745	
Evangeline	2,697	
Octane Enhancement:		
BEF	61,572	58,677
Accounted for on cost basis:		
Processing:		
VESCO	33,000	33,000
Total	$408,290	$298,954

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

	For Three Months Ended September 30,		For Nine Months Ended September 30,	
	2001	2000	2001	2000
Fractionation:				
BRF	$ 672	$ 434	$ 732	$ 1,171
BRPC	221	134	625	115
Promix	1,055	1,170	2,844	4,378
Pipeline:				
EPIK	150	(124)	(944)	1,846
Wilprise	370	135	233	297
Tri-States	789	694	889	2,215
Belle Rose	62	117	2	266
Dixie	240		1,200	
Starfish	789		2,762	
Ocean Breeze	8		22	
Neptune	1,035		2,824	
Nemo	(52)		(42)	
Evangeline	41		(108)	
Octane Enhancement:				
BEF	909	2,190	6,311	13,002
Total	$ 6,289	$ 4,750	$ 17,350	$ 23,290

The following table presents summarized income statement information for the unconsolidated affiliates accounted for by the equity method for the periods indicated (on a 100% basis):

	Summarized Income Statement data for the Three Months ended					
	September 30, 2001			September 30, 2000		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Fractionation:						
BRF	$ 5,827	$ 2,057	$ 2,084	$ 4,774	$ 1,282	$ 1,347

BRPC	2,414	717	738	2,333	398	448
Promix	11,122	3,439	3,461	12,242	3,956	4,019
Pipeline:						
EPIK	2,583	272	302	1,817	(323)	(282)
Wilprise	1,057	989	992	726	397	406
Tri-States	3,632	2,328	2,365	3,430	2,060	2,088
Belle Rose	489	144	149	536	279	279
Dixie (a)	14,534	6,860	4,138			
Starfish (b)	3,916	1,649	2,227			
Ocean Breeze (b)	34	4	26			
Neptune (b)	7,940	3,354	3,363			
Nemo (b)	213	(44)	(38)			
Evangeline (c)	43,486	1,287	32			
Octane Enhancement:						
BEF	54,955	2,060	2,725	77,331	6,202	6,570
Total	$152,202	$25,116	$22,564	$103,189	$14,251	$14,875

Summarized Income Statement data for the Nine Months ended

	September 30, 2001			September 30, 2000		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Fractionation:						
BRF	$ 13,652	$ 2,357	$ 2,434	$ 13,989	$ 3,504	$ 3,631
BRPC	9,247	1,949	2,085	2,333	211	383
Promix	32,465	9,327	9,425	36,968	14,097	14,274
Pipeline:						
EPIK	4,550	(1,510)	(1,423)	14,789	3,561	3,699
Wilprise	1,950	611	625	2,149	867	891
Tri-States	7,585	2,590	2,664	10,677	6,530	6,650
Belle Rose	1,043	(61)	(43)	1,802	645	645
Dixie (a)	38,570	15,161	8,967			
Starfish (b)	17,383	6,039	6,143			
Ocean Breeze (b)	121	91	91			
Neptune (b)	24,687	12,002	11,944			
Nemo (b)	213	(86)	(2)			
Evangeline (c)	91,095	2,297	(112)			
Octane Enhancement:						
BEF	168,873	17,982	18,932	214,761	38,575	39,007
Total	$411,434	$68,749	$61,730	$297,468	$67,990	$69,180

Notes to Summarized Income Statement data tables:
(a) Dixie became an equity method investment in October 2000.
(b) These entities became equity method investments of the Company beginning in January 2001.
(c) This entity became an equity method investment of the Company in April 2000 as a result of the Acadian Gas acquisition (see Note 3).

3. ACQUISITIONS

Since January 1, 2001, the Company has invested approximately $338 million (net of cash acquired) in natural gas pipeline businesses. These include:

- a combined $112 million in Ocean Breeze, Neptune, Nemo and Starfish (see Note 2 for a discussion of these equity investments); and,
- an initial $226 million for the purchase of Acadian Gas, LLC ("Acadian Gas").

Acquisition of Acadian Gas

On April 2, 2001, the Company acquired Acadian Gas from Shell US Gas and Power LLC, an affiliate of Shell, for approximately $226 million in cash using proceeds from the issuance of the $450 Million Senior Notes (see Note 5 for a discussion of long-term debt). The cash purchase price is subject to certain post-closing adjustments expected to be completed during the fourth quarter of 2001. The effective date of the transaction was April 1, 2001.

Acadian Gas is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. Acadian Gas' assets are comprised of the 438-mile Acadian, 577-mile Cypress and 27-mile Evangeline natural gas pipeline systems, which together have over 1.1 Bcf/d of capacity. These natural gas pipeline systems are wholly-owned by Acadian Gas with the exception of the Evangeline system in which Acadian Gas owns an aggregate 49.5% interest. The assets acquired include a leased natural gas storage facility located in Napoleonville, Louisiana.

The Acadian, Cypress and Evangeline systems link supplies of natural gas from onshore developments and, through connections with offshore pipelines, Gulf of Mexico production to local gas distribution companies, electric generation and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. In addition, these systems have interconnects with 12 interstate and four intrastate pipelines and a bi-directional interconnect with the U.S. natural gas marketplace at Henry Hub.

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

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

The balances related to the Acadian Gas acquisition included in the consolidated balance sheet dated September 30, 2001 are based upon preliminary information and are subject to change as additional information is obtained. As noted earlier, the initial purchase price is subject to certain post-closing adjustments attributable to working capital items expected to be finalized during the fourth quarter of 2001.

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

Pro Forma effect of Acadian Gas acquisition and recently acquired equity investments

The following table presents selected unaudited pro forma information for the three month period ended September 30, 2000 and nine month periods ended September 30, 2001 and 2000 as if the acquisition of the Acadian Gas natural gas pipeline systems had been made as of the beginning of the years presented. This table also incorporates selected unaudited pro forma information for the three and nine month periods ended September 30, 2000 relating to the Company's equity investments in Starfish, Ocean Breeze and Neptune.

The pro forma information is based upon data currently available to and certain estimates and assumptions by management and, as a result, are not necessarily indicative of 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.

	Three Months Ended September 30,	Nine Months Ended September 30,	
	2000	2001	2000
Revenues	$875,197	$2,748,318	$2,483,449
Income before extraordinary item and minority interest	$ 51,201	$ 226,837	$ 166,388
Net income	$ 50,683	$ 224,549	$ 164,705
Allocation of net income to			
Limited partners	$ 49,983	$ 221,387	$ 162,864
General Partner	$ 700	$ 3,162	$ 1,841
Units used in earnings per Unit calculations			
Basic	67,356	68,759	66,917
Diluted	83,182	84,819	81,862
Income per Unit before minority interest			
Basic	$0.75	$3.25	$2.46
Diluted	$0.61	$2.64	$2.01
Net income per Unit			
Basic	$0.74	$3.22	$2.43
Diluted	$0.60	$2.61	$1.99

4. RECENTLY ISSUED ACCOUNTING STANDARDS

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

At present, the Company's intangible assets include the values assigned to the 20-year Shell 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 value of the Shell Processing Agreement is being amortized over its contract term and the 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. Based upon initial interpretations of the new accounting standards, the Company anticipates that the Shell Processing Agreement will continue to be amortized over its contract term; however, the excess cost attributable to Mont Belvieu Associates will be reclassified to goodwill in accordance with the new standard and its amortization will cease (currently, $0.5 million in amortization expense annually). This goodwill would then be subject to impairment testing as prescribed in SFAS No. 142.

The Company is continuing to evaluate the complex provisions of SFAS No. 141 and SFAS No. 142 and has not adopted such provisions in its September 30, 2001 financial statements.

In addition to SFAS No. 141 and No. 142, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations", in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for the Company's fiscal year beginning January 1, 2003. In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment of long-lived assets and for long-lived assets to be disposed of. This statement is effective for the Company's fiscal year beginning January 1, 2002. Management is currently studying both SFAS No. 143 and No. 144 for their possible impact, if any, on the consolidated financial statements when they are adopted.

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

	September 30, 2001	December 31, 2000
Borrowings under:		
$350 Million Senior Notes, 8.25% fixed rate, due March 2005	350,000	350,000
$54 Million MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
$450 Million Senior Notes, 7.50% fixed rate, due February 2011	450,000	
Total principal amount	854,000	404,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt (see Note 10)	1,833	
Less unamortized discount on:		
$350 Million Senior Notes	(126)	(153)
$450 Million Senior Notes	(264)	
Less current maturities of long-term debt		
Long-term debt	$855,443	$403,847

The Company has the ability to borrow under the terms of its $250 Million Multi-Year Credit Facility and $150 Million 364-Day Credit Facility. The $150 Million 364-Day Credit Facility has an original maturity date of November 16, 2001. An amendment to the 364-Day Credit Facility to extend this date through November 15, 2002 was consented to by the lenders in early November 2001. No amount was outstanding under either of these two revolving credit facilities at September 30, 2001 or December 31, 2000.

At September 30, 2001, the Company had a total of $75 million of standby letters of credit capacity under its $250 Million Multi-Year Credit Facility of which $14.9 million was outstanding.

$450 Million Senior Notes. On January 24, 2001, a subsidiary of 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 used to acquire the Acadian Gas, Ocean Breeze, Neptune, Nemo and Starfish natural gas pipeline systems for $338 million and to finance the cost to construct certain NGL pipelines and related projects and for working capital and other general partnership purposes.

The $450 Million Senior Notes were issued under the indenture agreement dated March 15, 2000 which is also applicable to the $350 Million Senior Notes and therefore are subject to similar covenants and terms. As with the $350 Million Senior Notes, the $450 Million Senior Notes:

- o are subject to a make-whole redemption right;
- o are an unsecured obligation and rank equally with existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness; and,
- o are guaranteed by the Company through an unsecured and unsubordinated guarantee.

The issuance of the $450 Million Senior Notes was a final takedown under the December 1999 $800 million universal registration statement; therefore, the amount of securities available under this registration statement was reduced to zero. On February 23, 2001, the Company filed a $500 million universal shelf registration statement (the "February 2001 Registration Statement") covering the issuance of an unspecified amount of equity or debt securities or a combination thereof.

The Company was in compliance with the restrictive covenants associated with all of its fixed-rate and variable-rate debt instruments at September 30, 2001.

Increase in fair value of fixed-rate debt. Upon adoption of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted) on January 1, 2001, the Company recorded a $2.3 million non-cash increase in the fair value of its fixed-rate debt. SFAS No. 133 required that the Company's interest rate swaps and their associated hedged fixed-rate debt be recorded at fair value upon adoption of the standard. After adoption of the standard, the interest rate swaps were dedesignated due to differences in the estimated maturity dates of the interest rate swaps versus the fixed-rate debt. As a result, the fair value of the hedged fixed-rate debt will not be adjusted for future changes in fair value and the $2.3 million increase in the fair value of the debt will be amortized to earnings over the remaining life of the fixed-rate debt to which it applies, which approximates 10 years. The fair value adjustment of $2.3 million is not a cash obligation of the Company and does not alter the amount of the Company's indebtedness. See Note 10 for additional information concerning the Company's financial instruments.

6. CAPITAL STRUCTURE

Final issue of Special Units. On or about June 30, 2001, Shell met certain year 2001 performance criteria for the issuance of the last installment of 3.0 million non-distribution bearing, convertible Contingency Units (referred to as Special Units once they are issued). Under a contingent unit agreement with Shell executed as part of the 1999 TNGL acquisition, the Company issued these Special Units on August 2, 2001.

The value of these Special Units was determined to be $117.1 million using present value techniques. This amount increased the purchase price of the TNGL acquisition and the value of the Shell Processing Agreement when the issue was recorded in August 2001. This amount also increased the equity position of Shell in the Company by $117.1 million with the General Partner contributing $1.2 million to maintain its respective ownership in the Company. The $117.1 million increase in value of the 20-year Shell Processing Agreement will be amortized over the remaining life of the contract. As a result, amortization expense will increase by approximately $1.6 million per quarter ($6.5 million annually).

Conversion of Special Units to Common Units. In accordance with existing agreements with Shell, 5.0 million of Shell's original issue of Special Units converted into Common Units on August 2, 2001.

7. EARNINGS PER UNIT

Basic earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common and Subordinated Units outstanding during the period. Diluted earnings per Unit is computed by dividing net income available to limited partner interests by the weighted-average number of Common, Subordinated and Special Units outstanding during the period. The following table reconciles the number of shares used in the calculation of basic earnings per Unit and diluted earnings per Unit for the three and nine months ended September 30, 2001 and 2000:

	For Three Months Ended September 30,		For Nine Months Ended September 30,	
	2001	2000	2001	2000
Income before minority interest	$75,774	$50,777	$222,553	$166,959
General partner interest	(1,599)	(697)	(3,969)	(1,847)
Income before minority interest available to Limited Partners	74,175	50,080	218,584	165,112
Minority interest	(767)	(514)	(2,245)	(1,689)
Net income available to Limited Partners	$73,408	$49,566	$216,339	$163,423
BASIC EARNINGS PER UNIT				
Numerator				
Income before minority interest available to Limited Partners	$74,175	$50,080	$218,584	$165,112
Net income available to Limited Partners	$73,408	$49,566	$216,339	$163,423
Denominator				
Common Units outstanding	49,497	45,946	47,349	45,507
Subordinated Units outstanding	21,410	21,410	21,410	21,410
Total	70,907	67,356	68,759	66,917
Basic Earnings per Unit				
Income before minority interest available to Limited Partners	$ 1.05	$ 0.74	$ 3.18	$ 2.47

Net income available to Limited Partners	$ 1.04	$ 0.74	$ 3.15	$ 2.44
DILUTED EARNINGS PER UNIT				
Numerator				
Income before minority interest available to Limited Partners	$74,175	$50,080	$218,584	$165,112
Net income available to Limited Partners	$73,408	$49,566	$216,339	$163,423
Denominator				
Common Units outstanding	49,497	45,946	47,349	45,507
Subordinated Units outstanding	21,410	21,410	21,410	21,410
Special Units outstanding	15,196	15,826	16,060	14,945
Total	86,103	83,182	84,819	81,862
Diluted Earnings per Unit				
Income before minority interest available to Limited Partners	$ 0.86	$ 0.60	$ 2.58	$ 2.02
Net income available to Limited Partners	$ 0.85	$ 0.60	$ 2.55	$ 2.00

8. 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 $0.9 million and $1.3 million during the three and nine months ended September 30, 2001, respectively, and $0.2 million during the three months ended September 30, 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	$ 0.550	$ 0.550	Jan. 31, 2001	Feb. 9, 2001
	Second Quarter	$ 0.550	$ 0.550	Apr. 30, 2001	May 10, 2001
	Third Quarter	$ 0.5875	$ 0.5875	Jul. 31, 2001	Aug. 10, 2001
	Fourth Quarter (through November 12, 2001)	$ 0.6250	$ 0.6250	Oct. 31, 2001	Nov. 9, 2001

9. SUPPLEMENTAL CASH FLOW DISCLOSURE

The net effect of changes in operating assets and liabilities is as follows for the periods indicated:

	Nine Months Ended September 30,	
	2001	2000
(Increase) decrease in:		
Accounts receivable	$ 153,224	$(15,409)
Inventories	(51,753)	(66,270)
Prepaid and other current assets	(8,732)	1,841
Intangible assets		(4,805)
Other assets	(122)	(3,022)
Increase (decrease) in:		
Accounts payable	(79,413)	7,109
Accrued gas payable	(146,041)	47,517
Accrued expenses	(6,500)	(6,314)
Other current liabilities	22,851	12,749
Other liabilities	124	(397)
Net effect of changes in operating accounts	$(116,362)	$(27,001)

Business acquisitions (net of cash received) for the 2001 period reflects a net $226 million paid to an affiliate of Shell for Acadian Gas. Investments in and advances to unconsolidated affiliates for the 2001 period reflects $112 million paid to EPE for equity interests in various Gulf of Mexico natural gas pipeline systems. Capital expenditures for 2000 included $99.5 million for the purchase of the Lou-Tex Propylene Pipeline and related assets.

As a result of the Company's adoption of SFAS No. 133 on January 1, 2001, the Company records various financial instruments relating to interest rate and commodity positions at their respective fair values. For the nine months ended September 30, 2001, the Company recognized a net $39.4 million in non-cash mark-to-market gains related to increases in the fair value of these financial instruments ($34.6 million of this amount was attributable to financial instruments used in the Company's Processing segment with the remainder resulting from interest rate hedging activities). See Note 10 below for a further description of the Company's financial instruments.

Cash and cash equivalents at September 30, 2001 per the Statements of Consolidated Cash Flows excludes $9.0 million of restricted cash associated with hedging activities.

10. FINANCIAL INSTRUMENTS

The Company holds and issues financial instruments for the purpose of hedging the risks of certain identifiable and anticipated transactions primarily in its Processing segment. In general, the types of risks hedged are those relating to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates.

Commodity Financial Instruments

In its Processing segment, the Company's margin is directly exposed to commodity price risk. In order to manage this risk, the Company may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The 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 Company has adopted a commercial policy to manage its exposure to the risks associated with its Processing segment. The objective of this policy is to assist the Company in achieving its profitability goals while

maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by the General Partner. The Company enters into risk management transactions to manage price risk, basis risk, physical risk, or other risks related to the energy commodities 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 (such as those mentioned previously), 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.

On January 1, 2001, the Company adopted SFAS No. 133 which required the Company to record the fair market value of the commodity financial instruments on the balance sheet based upon then current market conditions. The fair market value of the then outstanding commodity financial instruments was a net liability of $42.2 million (the "cumulative transition adjustment") with an offsetting equal amount recorded in Other Comprehensive Income. The amounts in Other Comprehensive Income are reclassified to earnings in the accounting period associated with the hedged transaction (e.g. production month). The $42.2 million cumulative transition adjustment was or will be reclassified to earnings as follows:

- $21.7 million during the first quarter of 2001;
- $10.7 million during the second quarter of 2001;
- $7.3 million during the third quarter of 2001; with the remaining
- $2.5 million reclassified during the fourth quarter of 2001.

The cumulative transition adjustment recorded in Other Comprehensive Income at adoption of SFAS No. 133 will not be adjusted for changes in fair value; rather, any change in the fair value of these commodity financial instruments will be recorded in earnings (i.e., mark-to-market accounting treatment). The decision to record changes in the fair value of these commodity financial instruments directly to earnings rather than Other Comprehensive Income is based upon the determination by management that on an ongoing basis these commodity financial instruments would be ineffective under the guidelines of SFAS No. 133.

The Company has entered into commodity financial instruments for time periods extending through December 2002. These commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133. The Company continues to refer to these financial instruments as hedges inasmuch as this was the intent when such contracts were executed. This characterization is consistent with the actual economic performance of the contracts to date and the Company expects these financial instruments should continue to mitigate commodity price risk in the future. The specific accounting for these contracts, however, is consistent with the requirements of SFAS No. 133. As such, since these contracts do not qualify for hedge accounting under the specific guidelines of SFAS No. 133, the change in fair value of these commodity financial instruments are reflected on the balance sheet and in earnings (i.e., mark-to-market accounting treatment). The Company recognized income associated with its commodity financial instruments of $48.2 million and $118.5 million for the three and nine months ended September 30, 2001, respectively.

Other Financial Instruments - Interest rate swaps

The objective of holding interest rate swaps is to manage debt service costs by converting a portion of fixed-rate debt into variable-rate debt or a portion of variable-rate debt into fixed-rate debt. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount. Management believes that it is prudent to maintain an appropriate mixture of variable-rate and fixed-rate debt.

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

On January 1, 2001, the Company adopted SFAS No. 133 which required the Company to record the fair market value of the interest rate swaps on the balance sheet since the swaps were considered fair value hedges. SFAS No. 133 required that management determine (at the standard's adoption date) (a) the fair value of the swaps based upon then current market conditions and (b) the estimated maturity date of the swaps (including an estimate of the impact of any early termination clauses). The recording of the fair market value of the swaps was offset by an equal increase in the fair value of the associated hedged debt instruments and, therefore, had no impact on earnings upon transition. See Note 5 for further information regarding the impact of SFAS No. 133 on the Company's fixed-rate long-term debt.

After adoption, the interest rate swaps were dedesignated as hedging instruments due to differences between the maturity dates of the swaps and the associated hedged debt instruments. Dedesignation means that the financial instrument (in this case, the interest rate swaps) will not be accounted for using hedge accounting under SFAS No. 133. Upon dedesignation, any future changes in the fair value of the interest rate swap agreements will be recorded on the balance sheet through earnings. Dedesignation also entails that the previously associated hedged item (in this case, the debt instrument) will not be adjusted for future changes in its fair value. As a result, the $2.3 million change in fair value of the debt instrument recorded at the adoption date of SFAS No. 133 will be amortized to earnings over the life of the previously associated debt instrument of approximately 10 years.

The Company recognized income associated with its interest rate swaps of $4.0 million and $9.4 million for the three and nine months ended September 30, 2001. In October 2001, the Company realized $4.7 million of incremental cash flow through the early termination of a swap agreement.

Future issues

Due to the complexity of SFAS No. 133, the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, the initial conclusions reached by the Company regarding the application of SFAS No. 133 upon adoption may be altered. As a result, additional SFAS No. 133 transition adjustments may be recorded in future periods as the Company adopts new FASB interpretations.

11. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available and that are regularly evaluated by the chief operating decision maker in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

The Company has five reportable operating segments: Fractionation, Pipelines, Processing, Octane Enhancement and Other. The reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by the Chief Executive Officer of the General Partner. Fractionation primarily includes NGL fractionation, butane isomerization (converting normal butane into high purity isobutane) and polymer grade propylene fractionation services. Pipelines consists of both liquids and natural gas pipeline systems, storage and import/export terminal services. Processing includes the natural gas processing business and its related 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 based on gross operating margin. Gross operating margin reported for each segment represents operating income before depreciation and amortization, lease expense obligations retained by EPCO, gains and losses on the sale of assets and general and administrative expenses. In addition, segment gross operating margin is exclusive of interest expense, interest income (from unconsolidated affiliates or others), dividend income from unconsolidated affiliates, minority interest, extraordinary charges and other income and expense transactions. 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					Adjs.	
	Fractionation	Pipelines	Processing	Octane Enhancement	Other	and Elims.	Consol. Totals
Revenues from external customers							
for three months ended:							
September 30, 2001	$75,842	$127,687	$519,165		$635		$723,329
September 30, 2000	113,180	(2,735)	605,875		793		717,113
for nine months ended:							
September 30, 2001	252,087	313,832	1,951,176		1,946		2,519,041
September 30, 2000	302,081	21,191	1,730,976		2,059		2,056,307
Intersegment revenues							
for three months ended:							
September 30, 2001	41,273	22,464	244,145		99	$(307,981)	
September 30, 2000	46,538	12,083	165,761		93	(224,475)	
for nine months ended:							
September 30, 2001	127,058	67,874	486,111		290	(681,333)	
September 30, 2000	129,266	40,108	447,646		282	(617,302)	
Equity income in unconsolidated affiliates:							
for three months ended:							
September 30, 2001	1,948	3,432		$909			6,289
September 30, 2000	1,738	822		2,190			4,750
for nine months ended:							
September 30, 2001	4,201	6,838		6,311			17,350
September 30, 2000	5,664	4,624		13,002			23,290
Total revenues							
for three months ended:							
September 30, 2001	119,063	153,583	763,310	909	734	(307,981)	729,618
September 30, 2000	161,456	10,170	771,636	2,190	886	(224,475)	721,863
for nine months ended:							
September 30, 2001	383,346	388,544	2,437,287	6,311	2,236	(681,333)	2,536,391
September 30, 2000	437,011	65,923	2,178,622	13,002	2,341	(617,302)	2,079,597
Gross operating margin by segment							
for three months ended:							
September 30, 2001	35,189	22,415	52,026	909	310		110,849
September 30, 2000	32,510	10,292	29,083	2,190	429		74,504
for nine months ended:							
September 30, 2001	93,660	65,234	148,536	6,311	1,256		314,997
September 30, 2000	96,432	39,120	87,123	13,002	1,854		237,531
Segment assets at:							
September 30, 2001	354,012	698,766	125,071		9,572	73,734	1,261,155
December 31, 2000	356,207	448,920	126,895		8,942	34,358	975,322

Investments in and advances to unconsolidated affiliates at:						
September 30, 2001	94,230	219,488	33,000	61,572		408,290
December 31, 2000	105,194	102,083	33,000	58,677		298,954

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.

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

	For Three Months Ended September 30,		For Nine Months Ended September 30,	
	2001	2000	2001	2000
Total segment gross operating margin	$110,849	$74,504	$314,997	$237,531
Depreciation and amortization	(13,072)	(9,029)	(34,894)	(25,907)
Retained lease expense, net	(2,660)	(2,660)	(7,980)	(7,984)
(Gain) loss on sale of assets	5	27	392	(2,276)
Selling, general and administrative	(7,716)	(6,978)	(21,621)	(20,020)
Consolidated operating income	87,406	55,864	250,894	181,344
Interest expense	(12,610)	(7,486)	(35,928)	(23,330)
Interest income from unconsolidated affiliates		(88)	31	182
Dividend income from unconsolidated affiliates	392	2,241	2,024	6,236
Interest income - other	861	317	6,338	3,023
Other expense, net	(275)	(71)	(806)	(496)
Consolidated income before minority interest	$ 75,774	$50,777	$222,553	$166,959

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION.

For the Interim Periods ended September 30, 2001 and 2000

The following discussion and analysis should be read in conjunction with the unaudited consolidated financial statements and notes thereto of the Company included elsewhere herein.

Cautionary Statement regarding Forward-Looking Information and Risk Factors

This quarterly report on Form 10-Q 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," "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.

Risk Factors. An investment in the Company's securities involves a degree of risk. 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 natural gas liquid ("NGL") prices and production due to weather and other natural and economic 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, (g) the use of financial instruments to hedge commodity and interest rate risks which prove to be economically ineffective and (h) failure to complete one or more new projects on time or within budget.

The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond the Company's control. These factors include the level of domestic oil, natural gas and NGL production and development, the availability of imported oil and natural gas, actions taken by foreign oil and natural gas producing nations, the availability of transportation systems with adequate capacity, the availability of competitive fuels and products, fluctuating and seasonal demand for oil, natural gas and NGLs and conservation and the extent of governmental regulation of production and the overall economic environment.

The products that the Company processes, sells or transports are principally used as feedstocks in petrochemical manufacturing and in the production of motor gasoline and as fuel for residential and commercial heating. A reduction in demand for the Company's products or processing or transportation services by the petrochemical, refining or heating industries, whether because of general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, governmental regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could have a negative impact on the Company's results of operations. A material decrease in natural gas production or crude oil refining, as a result of depressed commodity prices or otherwise, or a decrease in imports of mixed butanes, could result in a decline in the volumes of NGLs processed or sold by the Company, thereby reducing revenue and operating income.

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 various uncertainties including the following key factors: (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.

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

Company Overview

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 Enterprise Products Company ("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 is a leading North American provider of a wide range of midstream energy services to its customers along the central and western Gulf Coast. The Company's services include the:

- gathering, transmission and storage of natural gas from both onshore and offshore Louisiana developments;
- purchase and sale of natural gas in south Louisiana;
- processing of natural gas into a merchantable and transportable form of energy that meets industry quality specifications by removing NGLs and impurities;
- fractionating 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;
- converting normal butane to isobutane through the process of isomerization;
- producing MTBE from isobutane and methanol;
- transporting NGL products to end users by pipeline and railcar;
- separating high purity propylene from refinery-sourced propane/propylene mix; and
- transporting high purity propylene to plastics manufacturers by pipeline.

Natural gas transported, processed and/or sold by the Company generally is consumed as fuel by residential, electric and industrial centers. NGL and petrochemical 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.

Company Operations and Assets

The Company's operations are concentrated in the Texas, Louisiana, and Mississippi Gulf Coast area. A large portion of these operations take place 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 Bcf/d and net capacity of 3.2 Bcf/d, 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 NGL and petrochemical 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 and petrochemical pipelines.

Beginning in January 2001, the Company owns varying equity interests in four Gulf of Mexico offshore Louisiana natural gas pipeline systems totaling 725 miles of pipeline (with an aggregate gross throughput capacity of 2.85 Bcf/d) and related assets. These equity interests were purchased from EPE at a cost of approximately $112 million. With the completion of the Acadian Gas, LLC ("Acadian Gas") acquisition in April 2001, the Company now owns varying interests in an additional 1,042 miles of natural gas pipeline systems (with an aggregate gross throughput capacity of over 1.1 Bcf/d) and related facilities located in south Louisiana. For additional information regarding these recent investments and business acquisitions, see "Recent acquisitions and other investments" below.

The Company's operating margins are primarily derived from services provided to its tolling customers and from merchant activities. In its tolling operations, the Company is paid a fee based on volumes processed, transported, stored or handled. The Company generally does not take title to products as part of its tolling operations; however, in those instances where title to products does transfer to the Company, the Company generally matches the timing and purchase price of the products with those of the sale of the products so as to reduce or eliminate exposure to fluctuations in commodity prices. Examples of the Company's tolling operations include isomerization tolling arrangements, propylene fractionation, liquids pipeline transportation services, fee-based marketing services and most NGL fractionation services. In addition, the Company's newly acquired natural gas pipeline businesses are viewed as fee-based operations. See "Recent acquisitions and other investments" below for a further discussion of the impact of commodity price risk on these operations.

In its merchant activities which are primarily reported in the Processing and Octane Enhancement segments, the Company is directly exposed to fluctuations in certain commodity prices. In the Company's isobutane merchant business (and to a certain extent its propylene fractionation activities), the Company takes title to feedstock products and sells processed end products. The Company's profitability from this type of merchant activity is dependent upon the prices of feedstocks and end products, which may vary on a seasonal basis. In order to limit the exposure to commodity price fluctuations in these business areas, the company attempts to match the timing and price of its feedstock purchases with those of the sales of end products. Operating margins from the company's natural gas processing (and related merchant businesses) are generally derived from the price spread earned on the sale of purity NGL products extracted from natural gas streams. To the extent the Company 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 operating margins are affected by the prices of NGLs and natural gas. As part of its natural gas processing and related merchant activities, the Company uses commodity financial instruments to reduce its exposure to the market risks associated with changes in natural gas and NGL prices.

Recent acquisitions and other investments

Natural gas pipelines

General. Since January 1, 2001, the Company has invested approximately $338 million (net of cash acquired) in natural gas pipeline businesses. These include an initial $226 million paid to Shell for the purchase of Acadian Gas (an onshore Louisiana system) and a combined $112 million paid to EPE for equity interests in four Gulf of Mexico natural gas pipelines (primarily offshore Louisiana systems). The acquisition of these natural gas pipeline businesses from EPE and Shell represent strategic investments for the Company. 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 provide opportunities for enhanced services to customers as well as generating additional fee-based cash flows. These businesses are accounted for as part of the Company's Pipelines operating segment.

Natural gas pipeline systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas at other points. Generally, natural gas transportation agreements provide these systems with a fee per unit of volume (generally in MMBtus) transported. Natural gas pipeline businesses (such as those of Acadian Gas) may also involve gathering and purchasing natural gas from producers and suppliers and transporting and reselling such natural gas to electric utility companies, local distribution companies, industrial customers, and affiliates of other pipeline and gas marketing companies as well as transporting and gathering natural gas for shippers on a fee basis. Overall, the Company's Gulf of Mexico systems do not take title to the natural gas that they transport; the shipper retains title and the associated commodity price risk. In the Company's Acadian Gas operations, it does take title to certain natural gas streams and is exposed to commodity price risk through its natural gas inventories and certain of its contracts.

The results of operation for the nine months ended September 30, 2001 include six month's impact of the Acadian Gas acquisition and nine month's impact of the Gulf of Mexico natural gas pipelines. See Note 3 of the Notes to Unaudited Consolidated Financial Statements for selected pro forma financial data regarding these transactions as if they had both occurred on January 1, 2001 and 2000.

Acadian Gas. On April 2, 2001, the Company acquired Acadian Gas from Shell US Gas and Power LLC, an affiliate of Shell, for approximately $226 million in cash using proceeds from the issuance of the $450 Million Senior Notes. The cash purchase price is subject to certain post-closing adjustments expected to be completed during the fourth quarter of 2001. The effective date of the transaction was April 1, 2001.

Acadian Gas is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. Acadian Gas' assets are comprised of the 438-mile Acadian, 577-mile Cypress and 27-mile Evangeline natural gas pipeline systems, which together have over 1.1 Bcf/d of capacity. These natural gas pipeline systems are wholly-owned by Acadian Gas with the exception of the Evangeline system in which Acadian Gas holds an approximate 49.5% interest. The assets acquired include a leased natural gas storage facility located in Napoleonville, Louisiana.

The Acadian, Cypress and Evangeline systems link supplies of natural gas from onshore developments and, through connections with offshore pipelines, Gulf of Mexico production to local gas distribution companies, electric generation and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. In addition, these systems have interconnects with 12 interstate and four intrastate pipelines and a bi-directional interconnect with the U.S. natural gas marketplace at Henry Hub.

Interests in four Gulf of Mexico natural gas pipeline systems. On January 29, 2001, the Company purchased equity interests in four Gulf of Mexico natural gas pipeline systems and related assets from EPE for $112 million, after taking into account certain post-closing adjustments.

The Company acquired a 50% equity interest in Starfish Pipeline Company LLC ("Starfish") which owns the Stingray natural gas pipeline system and a related natural gas dehydration facility. The Stingray system is a 375-mile FERC-regulated natural gas pipeline system that transports natural gas and injected condensate from certain production areas located in the Gulf of Mexico offshore Louisiana to onshore transmission systems located in south Louisiana. The natural gas dehydration facility is connected to the onshore terminal of the Stingray system in south Louisiana.

In addition to Starfish, the Company acquired a 25.67% equity interest in Ocean Breeze Pipeline Company LLC ("Ocean Breeze") and Neptune Pipeline Company LLC ("Neptune") as well as a 33.92% equity interest in Nemo Gathering Company, LLC ("Nemo"). Ocean Breeze and Neptune collectively own the Manta Ray and Nautilus natural gas gathering and transmission systems located in the Gulf of Mexico offshore Louisiana. The Manta Ray system

comprises approximately 225 miles of unregulated pipelines with a capacity of 750 MMcf/d and related equipment, the Nautilus system comprises approximately 101 miles of FERC-regulated pipelines with a capacity of 600 MMcf/d, and the Nemo system comprises approximately 24 miles of pipeline with a capacity of 300 MMcf/d.

Affiliates of Shell own the remaining equity interests in Starfish and varying interests in Ocean Breeze, Neptune and Nemo. An affiliate of Marathon Oil Company owns an interest in Ocean Breeze and Neptune. In addition, Shell is the operator of the assets held by Starfish, Ocean Breeze, Neptune and Nemo.

These natural gas pipeline systems and related assets are strategically located to serve continental shelf and deepwater developments in the central Gulf of Mexico. Management believes that the equity interests acquired from EPE complement and integrate well with those of the Acadian Gas acquisition. These investments are expected to benefit the Company's midstream focus by:

- broadening its midstream business by providing additional services to customers; and by
- contributing to the Company's ability to obtain anticipated increases in natural gas production from deepwater Gulf of Mexico development.

Management believes that these assets have a significant upside potential, since Shell and Marathon have dedicated production from over 1,000 square miles of Gulf of Mexico offshore Louisiana natural gas leases to these systems and only a small portion of this total has been developed to date.

Regulatory environment of natural gas systems. The Stingray and Nautilus natural gas pipeline systems are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. Generally, the FERC's authority extends to:

- transportation of natural gas, rates and charges;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- depreciation and amortization policies;
- acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- various other matters.

As noted above, the Stingray and Nautilus systems have tariffs established through filings with the FERC that have a variety of terms and conditions, each of which affect the operations of each system and their ability to recover fees for the services they provide. Generally, changes to these fees or terms can only be implemented upon approval by the FERC.

Collectively, the Acadian Gas and Gulf of Mexico pipeline systems acquired by the Company are subject to various governmental and environmental legislation. Each of these systems has a continuing program of inspection designed to ensure compliance with such legislation including pollution control and pipeline safety requirements. The Company believes that these systems are in substantial compliance with the applicable requirements.

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.

Diamond-Koch Storage Assets

On October 29, 2001, the Company announced that it had executed a letter of intent to acquire storage facilities from affiliates of Ultramar Diamond Shamrock Corporation and Koch Industries, Inc. The storage

facilities consist of 30 salt dome storage caverns with a permitted capacity of 77 million barrels located near the Company's Mont Belvieu complex. These caverns provide storage services for mixed NGLs, ethane, propane, butanes, natural gasoline and olefins, such as ethylene, polymer grade propylene, chemical grade propylene and refinery grade propylene. The completion of this transaction is subject to the execution of a definitive agreement and regulatory approvals. The parties anticipate the transaction to be completed by the end of 2001.

Current Business Environment

During the third quarter of 2001, the U.S. NGL industry continued to recover from the first quarter of 2001 as a result of declining energy prices, particularly that of natural gas. The lower energy costs have contributed to increased volumes and profitability across many of the Company's business operations. The decline in natural gas prices from the record levels of the first quarter of 2001 resulted in increased NGL extraction rates throughout the gas processing industry. Consequently, the Company is continuing to see an increase in NGL volumes available for fractionation and/or transportation.

Natural gas prices continued to decline in the third quarter of 2001 compared to the first six months of 2001. After peaking at near $10 per MMBtu in January 2001, natural gas prices decreased to less than $3 per MMBtu in October 2001 which is within the historical norm in terms of relative value to other forms of energy. Industry expectations are that natural gas prices will remain within the historical norm relative to other forms of energy for most of the upcoming winter due to the weak domestic economy and a strong supply picture. Although the lower prices have led some producers to scale back their gas exploration and production projects, the industry expects that the current short-term imbalance of excess supply is temporary.

In the third quarter of 2001, NGL prices declined along with those of other forms of energy. The resultant loss of value has been mitigated (or in some cases, reversed) by the Company's hedging activities. During the fourth quarter of 2001, the Company expects that natural gas and NGL prices will be within the historical range in terms of relative value with other forms of energy.

The Company's recently acquired natural gas pipeline businesses have benefited from increased drilling activities associated with expected long-term demand growth for natural gas. The expected long-term outlook for natural gas is positive as new gas-fired electric generation facilities commence operations and the domestic economy rebounds. Also, the Company's Nemo natural gas pipeline started operations in August 2001. This system is currently transporting approximately 50,000 MMBtu/d of natural gas from the Shell Brutus field, which began production during the third quarter of 2001. When fully developed in early 2002, the Shell Brutus field is expected to produce up to 150,000 MMBtu/d of natural gas which will be transported through Nemo. This additional volume will flow from Nemo into the Manta Ray/Nautilus pipeline systems and ultimately be processed at the Company's Neptune gas processing plant (at full extraction rates in 2002, the Brutus field production is expected to increase the Company's equity NGL production by up to 10 MBPD).

At the Company's gas processing facilities, equity NGL production volumes were 62 MBPD in the third quarter of 2001, little changed from the second quarter of 2001 but significantly improved from the 46 MBPD of the first quarter of 2001. The equity NGL production rate seen in the first quarter was the result of minimal NGL extraction rates caused by the abnormally high cost of natural gas. As natural gas prices moderated in the second and third quarters, NGL extraction rates at the Company's gas processing facilities and those of other industry participants increased resulting in additional volumes throughout the NGL value chain; however, many gas processing plants were still not operating at full extraction rates due to below average processing margins. With the current natural gas price environment, management anticipates that the Company's natural gas processing facilities will operate at full NGL extraction rates during the fourth quarter. Overall, the Company expects equity NGL production to average approximately 80 MBPD during the fourth quarter of 2001.

During the third quarter, the Company's isomerization and related merchant businesses experienced margins and volumes consistent with refinery demand associated with the end of the summer driving season. Isomerization volumes are expected to remain near 80 MBPD during the fourth quarter of 2001. Propylene fractionation margins are expected to remain flat during the fourth quarter due to the weak economy and

additional supplies coming to the market from new third party facilities. Once domestic economic conditions improve, the Company expects that demand for propylene fractionation services will increase as the market absorbs the added supplies.

NGL fractionation services at Mont Belvieu are competitive due to continued excess NGL fractionation capacity at this industry hub. With newly contracted volumes such as those from the Sea Robin gas processing facility in Louisiana, the Company has raised the utilization rates of its Mont Belvieu NGL fractionator to near capacity. The BRF NGL fractionation facility, an equity investment of the Company, is projected to run at or near full capacity during the fourth quarter and the Promix NGL fractionation facility, another equity investment of the Company, is expected to run at 110 MBPD, both on strong demand. Management anticipates that its Norco NGL fractionation facility will process at rates near its capacity of 50 MBPD during the fourth quarter of 2001 and show margin improvement as in-kind fees increase with the expected rise in overall NGL pricing.

With regards to its major liquids pipelines, the Company expects its Louisiana Pipeline System to benefit from the seasonal rise in propane shipments that are carried on the Dixie Pipeline with the strongest movements anticipated during the fourth quarter of 2001. In addition, the Company expects that the projected November 2001 completion of its Napoleonville to Sorrento pipeline (which is an expansion of its Louisiana Pipeline System capacity) will result in increased shipments of natural gasoline to refineries along the Mississippi River and transport of refinery grade propylene from Mississippi River refineries west to the Mont Belvieu market. This increase in pipeline volumes is expected to be obtained by attracting volumes that have historically been transported by barge which is a more costly means of transportation versus by pipeline. The Company's Lou-Tex NGL Pipeline is expected to benefit from the addition of new customer volumes that will add approximately 6 MBPD of throughput volume in November 2001.

EPIK's financial performance is expected to seasonally improve during the fourth quarter of 2001. Exports of butane and propane are expected to increase as a result of moderating domestic prices for both products relative to foreign markets. This situation should make these products more competitive on the world market and EPIK should benefit from a higher utilization of the export terminal. Activity at the Company's Houston Ship Channel import facility is expected to be consistent with the fourth quarters of previous years.

The Company's MTBE business is encountering the normal seasonal decline in spot MTBE prices. MTBE spot prices are generally stronger during the April to September period of each year which corresponds with the summer driving season. Management anticipates that equity earnings from its investment in BEF will be near breakeven during the fourth quarter of 2001 as a result of this pricing environment.

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

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Polymer Grade Propylene, $/pound
	(a)	(b)	(a)	(a)	(a)	(a)	(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)	$7.00	$28.81	$0.43	$0.55	$0.63	$0.69	$0.23
Second quarter	$4.61	$27.88	$0.33	$0.46	$0.53	$0.63	$0.19
Third quarter	$2.84	$26.65	$0.25	$0.41	$0.50	$0.49	$0.16

(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 peaked at approximately $10 per MMBtu in January 2001

Results of Operation of the Company

The Company has five reportable operating segments: Fractionation, Pipelines, Processing, Octane Enhancement and Other. Fractionation primarily includes NGL fractionation, butane isomerization (converting normal butane into high purity isobutane) and polymer grade propylene fractionation services. Pipelines consists of liquids and natural gas pipeline systems, 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 based on 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 for the three and nine month periods ended September 30, 2001 and 2000 were as follows:

	For Three Months Ended September 30,		For Nine Months Ended September 30,	
	2001	2000	2001	2000
Gross operating margin by segment:				
Fractionation	$35,189	$32,510	$ 93,660	$ 96,432
Pipeline	22,415	10,292	65,234	39,119
Processing	52,026	29,083	148,536	87,123
Octane enhancement	909	2,190	6,311	13,002
Other	310	429	1,256	1,855
Gross operating margin total	110,849	74,504	314,997	237,531
Depreciation and amortization	13,072	9,029	34,894	25,907
Retained lease expense, net	2,660	2,660	7,980	7,984
Loss (gain) on sale of assets	(5)	(27)	(392)	2,276
Selling, general and administrative expenses	7,716	6,978	21,621	20,020
Consolidated operating income	$87,406	$55,864	$250,894	$181,344

The Company's significant production and other volumetric data (on a net basis) for the three and nine month periods ended September 30, 2001 and 2000 were as follows:

	For the three months ended September 30,		For the nine months ended September 30,	
	2001	2000	2001	2000
MBPD, Net				
Equity NGL Production	62	73	57	72
NGL Fractionation	224	214	198	216
Isomerization	81	84	82	77
Propylene Fractionation	34	34	31	34
Octane Enhancement	5	6	4	5
Major NGL and Petrochemical Pipelines	479	289	452	334
MMBtu/D, Net				
Natural Gas Pipelines	1,426,463		1,342,104	

Three Months Ended September 30, 2001 compared with Three Months Ended September 30, 2000

Revenues, Costs and Expenses and Operating Income. The Company's revenues increased to $729.6 million in 2001 compared to $721.9 million in 2000. The Company's operating costs and expenses decreased to $634.5

million versus $659.0 million in 2000. Operating income increased to $87.4 million in 2001 from $55.9 million in 2000. Third quarter 2001 revenues and expenses for Fractionation, Processing, Octane Enhancement and Other decreased relative to third quarter 2000 amounts primarily due to falling NGL prices and energy cost-related fees and expenses. Offsetting these declines was an increase in revenues and expenses in the Pipelines segment attributable to the acquisition of Acadian Gas and the Gulf of Mexico natural gas pipeline systems in 2001. The majority of the increase in operating income for 2001 is attributable to $48.2 million in income relating to the Company's commodity hedging activities.

Fractionation. The Company's gross operating margin for the Fractionation segment increased to $35.2 million in 2001 from $32.5 million in 2000. NGL fractionation margin declined $0.3 million quarter-to-quarter

while net processing volumes increased to 224 MBPD in 2001 from 214 MBPD in 2000. The slight decline in margin is attributable to lower processing fees at Norco which are tied to NGL prices that were lower quarter-to-quarter. The increase in NGL fractionation volumes is primarily due to the receipt of Sea Robin mixed NGL volumes at the Company's Mont Belvieu fractionation facilities via the Lou-Tex NGL pipeline. The Company's isomerization business posted a slight $0.1 million decrease primarily due to a decline in volumes from 84 MBPD in 2000 to 81 MBPD in 2001. The impact of lower isomerization volumes was offset by a decrease in energy-related costs and other expenses. Gross operating margin from propylene fractionation increased $2.2 million on volumes of 34 MBPD for both periods. The increase in propylene fractionation margin is attributable to lower energy costs and other expenses.

Pipelines. The Company's gross operating margin for the Pipelines segment was $22.4 million in 2001 compared to $10.3 million in 2000. Of the $12.1 million increase, $4.2 million is attributable to natural gas pipelines acquired in 2001 (i.e., Acadian Gas and the Gulf of Mexico systems). Natural gas pipeline volumes averaged 1,426 BBtu/d on a net basis. Margin from the recently completed Lou-Tex NGL Pipeline increased $4.2 million quarter-to-quarter on volumes of 34 MBPD. The Lou-Tex NGL Pipeline was completed during the fourth quarter of 2000. Overall, net liquids throughput volumes increased to 479 MBPD in 2001 compared with 289 MBPD in 2000. The majority of the 190 MBPD increase in liquids throughput volumes is attributable to (i) a 60 MBPD increase on the Louisiana Pipeline System due to strong demand for services, (ii) a 78 MBPD combined increase at the Houston Ship Channel import facility and on its related pipeline system related to seasonal butane import activity and (iii) the 34 MBPD from the Lou-Tex NGL Pipeline mentioned previously. The volume increases on the Louisiana Pipeline System and the import dock and its related pipeline system contributed to a combined $2.5 million increase in margin quarter-to-quarter.

Processing. For the third quarter of 2001, the Processing segment generated gross operating margin of $52.0 million compared to $29.1 million during the same period in 2000. The Processing segment includes the Company's natural gas processing business and related merchant activities. The Company's equity NGL production was 62 MBPD for the 2001 quarter versus 73 MBPD for the same quarter in 2000. The decline in volume is related to the 2000 period reflecting near maximized NGL recoveries supported by strong NGL economics. The 2001 equity NGL production rate reflects slightly less favorable extraction economics but is greatly improved relative to the first quarter of 2001's 46 MBPD when natural gas prices (a major expense of gas processing operations) peaked at nearly $10 per MMBtu.

Gross operating margin for the Processing segment includes the results of the Company's commodity hedging activities. The 2001 period includes $48.2 million in income from commodity financial instruments compared to $5.4 million for the 2000 period. The Company employs various hedging strategies to mitigate the effects of fluctuating commodity prices (primarily NGL prices) on its natural gas processing business and related merchant activities.

A large number of the Company's commodity financial instruments are based on the historical relationship between natural gas prices and NGL prices. This type of hedging strategy utilizes the forward sale of natural gas at a fixed-price with the expected margin on the settlement of the position offsetting or mitigating changes in the anticipated margins on NGL merchant activities and the value of the Company's equity NGL production. During the third quarter of 2001, the Company benefited from a decline in natural gas prices relative to its fixed positions. The decline in natural gas prices allowed the Company to realize net cash gains on the settlement and early closeout of certain positions of approximately $66.1 million. The $17.9 million difference between the realized amount and the $48.2 million in income from commodity financial instruments is related to changes in non-cash mark-to-market amounts. The non-cash mark-to-market income on positions open at September 30, 2001 was $34.6 million (based on market prices at that date).

If natural gas prices had not declined to the degree seen during the quarter, less income or a loss on hedging activities may have resulted offset somewhat by correlative higher NGL prices which would have increased the value of the Company's equity NGL production. A variety of factors influence whether or not the Company's hedging strategy is successful. For additional information regarding the Company's commodity financial instruments, see Item 3 "Quantitative and Qualitative Disclosures about Market Risk" on page 38.

Octane Enhancement. The Company's gross operating margin for Octane Enhancement decreased $1.2 million in the third quarter of 2001 compared to 2000 levels. MTBE production, on a net basis, was 5 MBPD for the 2001

quarter versus 6 MBPD for the 2000 quarter. The decline in margin is primarily due to the lower MTBE volumes and a decrease in by-product revenues offset by lower energy-related costs quarter-to-quarter.

Interest expense. Interest expense for the third quarter of 2001 increased $5.1 million over the same period in 2000. The increase is attributable higher average debt levels in 2001 of $854.0 million compared with $437.0 million in 2000. The higher debt levels are associated with the issuance of the $450 Million Senior Notes in January 2001 of which the proceeds were used to acquire Acadian Gas and interests in the Gulf of Mexico natural gas pipeline systems.

Nine Months Ended September 30, 2001 compared with Nine Months Ended September 30, 2000

Revenues, Costs and Expenses and Operating Income. The Company's revenues increased to $2.5 billion in 2001 compared to $2.1 billion in 2000. The Company's operating costs and expenses increased to $2.3 billion in 2001 from $1.9 billion in 2000. Operating income increased to $250.9 million in 2001 from $181.3 million in 2000. The rise in year-to-date revenues is primarily due to the addition of Acadian Gas' revenues and increased merchant business activities. The Acadian Gas acquisition was effective April 1, 2001. The rise in year-to-date expenses is attributable to expenses of Acadian Gas, higher than normal natural gas prices during the first half of 2001 which affected energy-related operating costs at the Company's facilities offset by significant income from the Company's commodity hedging activities. As a result, operating income was positively influenced by the above noted factors.

Fractionation. The Company's gross operating margin for the Fractionation segment decreased to $93.7 million in 2001 from $96.4 million in 2000. NGL fractionation margin decreased $14.9 million primarily due to lower processing volumes and higher energy-related operating costs. NGL fractionation net volumes decreased to 198 MBPD for the first nine months of 2001 compared to 216 MBPD during the same period in 2000. The decrease is the result of lower NGL extraction rates at gas processing facilities in early 2001 (due to the high cost of natural gas) versus 2000 when the industry was maximizing NGL production. For the first nine months of 2001, gross operating margin from isomerization services increased $11.1 million compared to 2000 primarily due to an increase in volumes and toll processing fees. Isomerization volumes increased to 82 MBPD during the first nine months of 2001 versus 77 MBPD during the same period in 2000 due to increased demand for the Company's services. Gross operating margin from propylene fractionation decreased $0.5 million compared to the first nine months of 2000 primarily due to higher energy costs, moderating prices and lower volumes. Net propylene fractionation volumes were 31 MBPD in 2001 versus 34 MBPD in 2000.

Pipelines. The Company's gross operating margin for the Pipelines segment was $65.2 million in 2001 compared to $39.1 million in 2000. Of the $26.1 million increase, $11.0 million is attributable to natural gas transportation investments acquired in 2001 (i.e., Acadian Gas and the Gulf of Mexico systems). The Company's Lou-Tex NGL Pipeline (completed in the fourth quarter of 2000) added $9.3 million on volumes of 26 MBPD. In addition, margin on the Company's Lou-Tex Propylene Pipeline for 2001 was $3.4 million higher than 2000 (primarily due to this asset being purchased in March 2000). Demand for imported mixed NGLs (particularly commercial butanes) resulted in a $5.1 million increase in margins for the Houston Ship Channel import facility and related pipeline system. The increase in commercial butane imports was related to the seasonal demand for isobutane which occurred between February and May 2001.

Processing. For the first nine months of 2001, the Processing segment generated gross operating margin of $148.5 million compared to $87.1 million during the same period in 2000. The $61.4 million increase in margin is attributable to the Company's commodity hedging activities and merchant business offset by lower equity NGL production and prices and higher energy-related costs.

As discussed earlier under the Processing segment's quarter-to-quarter variance explanation (see page 31), the Company employs various hedging strategies in an effort to mitigate the effects of fluctuating commodity prices (primarily NGL prices) on its natural gas processing business and related merchant activities. Gross operating margin for the first nine months of 2001 reflects $118.5 million in income from commodity financial instruments compared with $8.4 million for the same period in 2000. Of the $118.5 million in hedging income recognized during 2001, $83.9 million has been realized with the difference of $34.6 million attributable to non-cash mark-to-market income on positions that were open at September 30, 2001. The September 30, 2001 $34.6

million in mark-to-market income is based on market prices at that date. The change in hedging income between the 2001 and 2000 periods more than offset the effects of the lower equity NGL volumes and prices and higher energy-related costs. A variety of factors influence whether or not the Company's hedging strategy is successful. For additional information regarding the Company's commodity financial instruments, see Item 3 "Quantitative and Qualitative Disclosures about Market Risk" on page 38.

Processing's merchant business benefited from strong demand for propane in the first quarter of 2001 for heating and isobutane in the second quarter of 2001 for refining. Equity NGL production averaged 57 MBPD during the 2001 period versus 72 MBPD during the 2000 period. The 2001 rate of 57 MBPD reflects the very low 46 MBPD NGL extraction rates of the first quarter of 2001 when natural gas prices (a major expense of gas processing operations) were at their peak. As natural gas prices have declined since January 2001, equity NGL production has returned to higher levels. The 2000 equity NGL production rate reflects a period in which gas processors were operating facilities at near full NGL extraction rates.

Octane Enhancement. The Company's gross operating margin for Octane Enhancement decreased $6.7 million in the first nine months of 2001 compared with the same period in 2000. MTBE production, on a net basis, was 4 MBPD in 2001 and 5 MBPD in 2000. The decrease in volumes is attributable to a prolonged maintenance outage which lasted from December 2000 until February 2001. The decline in margin is primarily due to the lower MTBE volumes, a decrease by-product revenues and an increase in energy-related and other expenses period-to-period.

Interest expense. Interest expense for the first nine months of 2001 increased $12.6 million over the first nine months of 2000. The increase is primarily due to additional interest expense associated with the $450 Million Senior Notes issued in January 2001 of which the proceeds were used to acquire Acadian Gas and interests in the Gulf of Mexico natural gas pipeline systems.

Liquidity and Capital Resources

General. The Company's primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures (both maintenance and expansion-related), business acquisitions and distributions to its partners. The Company expects to fund its short-term needs for such items as maintenance capital expenditures and quarterly distributions to its 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 September 30, 2001, availability under the Company's revolving bank credit facilities was $400 million (which may be increased to $500 million under certain conditions). In addition to the existing revolving bank credit facilities, a subsidiary of the Company issued $450 million of public debt in January 2001 (the "$450 Million Senior Notes") 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 used to acquire the Acadian Gas and Gulf of Mexico natural gas pipeline systems, to finance the cost to construct certain NGL pipelines and related projects and for working capital and other general partnership purposes. On February 23, 2001, 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 expansions or acquisitions.

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, Baa2 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.

Consolidated Cash Flows for the nine months ended September 30, 2001 and 2000. Cash inflows from operating activities were $124.8 million for the first nine months of 2001 compared to $180.8 million for the same period in 2000. Cash flows from operating activities primarily reflect the effects of net income, depreciation and amortization, equity income and distributions from unconsolidated affiliates, fluctuations in fair values of financial instruments and changes in operating accounts. Net income increased $55.0 million for 2001 compared to 2000 primarily due to reasons mentioned previously under Results of Operation of the Company. Depreciation and amortization increased a combined $9.3 million in 2001 over 2000 totals primarily due to additional capital expenditures and business acquisitions.

Equity in income of unconsolidated affiliates decreased $5.9 million in 2001 compared with 2000 levels. The decrease is attributable to (i) lower earnings from NGL fractionation and pipeline investments in 2001 relative to 2000 primarily due to a decrease in available NGL volumes resulting from the low extraction rates in early 2001 and (ii) a decline in BEF margins (see Octane Enhancement discussion under Results of Operation of the Company) offset by equity earnings from the newly acquired Gulf of Mexico natural gas pipeline systems. The Company received $30.6 million in distributions from its equity method investments in 2001 compared to $26.0 million in 2000. The $4.6 million increase is primarily related to distributions received from the Company's newly acquired Gulf of Mexico natural gas pipeline systems. Of the operating accounts, changes in 2001 receivable and payable balances have been influenced by the decline in natural gas and NGL prices since the beginning of the year. Overall, the net effect of changes in operating accounts from period to period is generally the result of timing of NGL sales and purchases near the end of the period and changes in inventory values related to pricing or volumes or a combination thereof.

Operating cash flows also includes an adjustment for the $39.4 million in non-cash mark-to-market income related to commodity and interest rate hedging activities. Of this amount, $34.6 million is attributable to the commodity financial instrument portfolio with the balance pertaining to interest rate swaps. For a more complete description of the Company's risk management policies and potential exposures, see "Item 3. Quantitative and Qualitative Disclosures about Market Risk" and Note 10 of the Notes to Unaudited Consolidated Financial Statements.

Cash used for investing activities was $437.6 million in 2001 compared to $195.9 million in 2000. Cash outflows included capital expenditures of $92.6 million in 2001 versus $200.2 million in 2000. Capital expenditures for 2000 include $99.5 million for the purchase of the Lou-Tex Propylene Pipeline and related assets. In addition, capital expenditures include maintenance capital project costs of $3.8 million in 2001 and $2.3 million in 2000. The Company's completion of the Acadian Gas business acquisition resulted in an initial payment to Shell of $225.7 million in April 2001, subject to certain post-closing purchase price adjustments. The 2000 period also includes $6.5 million in cash receipts related to the Company's participation in the BEF note, which was extinguished in May 2000 with BEF's final principal payment. Lastly, investing cash outflows in 2001 includes $119.9 million in investments in and advances to unconsolidated affiliates compared to $2.3 million in 2000. The increase is due to the purchase of the Gulf of Mexico natural gas pipeline systems in January 2001.

Cash receipts from financing activities were $310.5 million during 2001 compared to $51.3 million in 2000. Cash flows from financing activities are primarily affected by repayments of debt, borrowings under debt agreements and distributions to partners. The 2001 period includes proceeds from the $450 Million Senior Notes issued in January 2001 whereas the 2000 period includes proceeds from the $350 Million Senior Notes and $54 Million MBFC Loan and the associated repayments on various bank credit facilities. Cash outlays for financing activities also include $8.8 million paid by a consolidated trust to purchase Common Units to fund a long-term incentive plan (see "Units acquired by Trust" below).

Distributions to partners and the minority interest increased to $118.3 million in 2001 from $104.4 million in 2000 primarily due to an increase in the quarterly distribution rate. See Note 8 of the Notes to Unaudited

Consolidated Financial Statements for a history of quarterly distribution rates and increases since the first quarter of 1999. In October 2001, the Company announced that it had again increased its quarterly distribution rate from $0.5875 per Common Unit to $0.625 per Common Unit beginning with the distribution payable in November 2001. This increase in the quarterly distribution rate in conjunction with the conversion of 5.0 million of the Shell Special Units into Common Units in August 2001 (see "Issuance of last installment of Special Units to Shell" below) will result in the quarterly cash outlay for distributions to the partners increasing by approximately $5.7 million.

During the first nine months of 2001, the Company has invested $338 million in business acquisitions and the purchase of equity interests in other companies. These investments include the acquisition of Acadian Gas and interests in four natural gas pipelines in the Gulf of Mexico. 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. In addition, management believes that the Company is well positioned to continue to grow through acquisitions that will expand its platform of assets and through internal growth. The Company anticipates that it will achieve its conservative annual growth objective for 2001: investing over $400 million in energy infrastructure projects and acquisitions while increasing its cash distribution rate to Unitholders by at least 10% for the full year.

The cash distribution policy (as managed by the General Partner at its sole discretion) has allowed the Company to retain a significant amount of cash flow for reinvestment in the growth of the business. Over the last two years, the Company has reinvested approximately $323.2 million to fund expansions and business acquisitions. Management believes the cash distribution policy provides financial flexibility in executing the Company's growth strategy.

Future Capital Expenditures. The Company forecasts that $72.1 million will be spent during the remainder of 2001 on currently approved capital projects that will be recorded as property, plant and equipment (the majority of which relate to various pipeline projects). In addition, the Company estimates that its share of currently approved capital expenditures in the projects of its unconsolidated affiliates will be approximately $0.5 million for the remainder of 2001.

As of September 30, 2001, the Company had $8.2 million in outstanding purchase commitments attributable to its capital projects. Of this amount, $7.7 million is related to the construction of assets that will be recorded as property, plant and equipment and $0.5 million is associated with capital projects which will be recorded as additional investments in unconsolidated affiliates.

New environmental regulations in the state of Texas 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. The technical practicality and economic reasonableness of these regulations have been challenged under state law in litigation filed on January 19, 2001, against the Texas Natural Resource Conservation Commission and its principal officials in the District Court of Travis County, Texas, by a coalition of major Houston-Galveston area industries including the Company. Until the litigation is resolved, the precise level of technology to be employed and the cost for modifying the facilities to achieve the required amount of reductions cannot be determined. The litigation has been stayed by agreement of the parties pending the outcome of expanded, cooperative scientific research to more precisely define sources and mechanisms of air pollution in the Houston-Galveston area. Completion of this research is anticipated in mid-2002. Regardless of the results of the research and the outcome of the 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. Capital funds have been budgeted for work in 2002 that will begin making emissions reduction modifications on certain Mont Belvieu facilities. The methods employed to achieve these reductions will be compatible with whatever regulatory requirements are eventually put in place. For additional information about this litigation, see the discussion under the topic Clean Air Act--General on page 22 of the Company's Form 10-K for fiscal 2000.

Long-term Debt. Long-term debt consisted of the following at:

	September 30, 2001	December 31, 2000
Borrowings under:		
$350 Million Senior Notes, 8.25% fixed rate, due March 2005	350,000	350,000
$54 Million MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
$450 Million Senior Notes, 7.50% fixed rate, due February 2011	450,000	
Total principal amount	854,000	404,000
Unamortized balance of increase in fair value related to		

hedging a portion of fixed-rate debt (see Note 10)	1,833	
Less unamortized discount on:		
$350 Million Senior Notes	(126)	(153)
$450 Million Senior Notes	(264)	
Less current maturities of long-term debt		
Long-term debt	$855,443	$403,847

The Company has the ability to borrow under the terms of its $250 Million Multi-Year Credit Facility and $150 Million 364-Day Credit Facility. The $150 Million 364-Day Credit Facility has an original maturity date of November 16, 2001. An amendment to the 364-Day Credit Facility to extend this date through November 15, 2002 was consented to by the lenders in early November 2001. No amount was outstanding under either of these two revolving credit facilities at September 30, 2001 or December 31, 2000.

At September 30, 2001, the Company had a total of $75 million of standby letters of credit capacity under its $250 Million Multi-Year Credit Facility of which $14.9 million was outstanding.

On January 24, 2001, a subsidiary of 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 used to acquire the Acadian Gas and Gulf of Mexico natural gas pipeline systems and to finance the cost to construct certain NGL pipelines and related projects and for working capital and other general partnership purposes.

The $450 Million Senior Notes were issued under the indenture agreement dated March 15, 2000 which is also applicable to the $350 Million Senior Notes and therefore are subject to similar covenants and terms. As with the $350 Million Senior Notes, the $450 Million Senior Notes are:

- subject to a make-whole redemption right;
- an unsecured obligation and rank equally with existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness; and,
- guaranteed by the Company through an unsecured and unsubordinated guarantee.

The Company was in compliance with the restrictive covenants associated with the $350 Million and $450 Million Senior Notes at September 30, 2001.

The issuance of the $450 Million Senior Notes was a final takedown under the December 1999 Registration Statement; therefore, the amount of securities available under this universal shelf registration statement was reduced to zero. On February 23, 2001, the Company filed a $500 million universal shelf registration statement (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 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.

Upon adoption of Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted) on January 1, 2001, the Company recorded a $2.3 million non-cash increase in the fair value of its fixed-rate debt. SFAS No. 133 required that the Company's interest rate swaps and their associated hedged fixed-rate debt be recorded at fair value upon adoption of the standard. After adoption of the standard, the interest rate swaps were dedesignated due to differences in the estimated maturity dates of the interest rate swaps versus the fixed-rate debt. As a result, the fair value of the hedged fixed-rate debt will not be adjusted for future changes in fair value and the $2.3 million increase in the fair value of the debt will be amortized to earnings over the remaining life of the fixed-rate debt to which it applies, which approximates 10 years. See Note 5 and Note 10 of the Notes to Unaudited Consolidated Financial Statements for additional information regarding interest rate swaps and the associated change in the fair value of the fixed-rate debt.

Recently Issued Accounting Standards

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

At present, the Company's intangible assets include the values assigned to the 20-year Shell 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 value of the Shell Processing Agreement is being amortized over its contract term and the 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. Based upon initial interpretations of the new accounting standards, the Company anticipates that the Shell Processing Agreement will continue to be amortized over its contract term; however, the excess cost attributable to Mont Belvieu Associates will be reclassified to goodwill in accordance with the new standard and its amortization will cease (currently, $0.5 million in amortization expense annually). This goodwill would then be subject to impairment testing as prescribed in SFAS No. 142.

The Company is continuing to evaluate the complex provisions of SFAS No. 141 and SFAS No. 142 and has not adopted such provisions in its September 30, 2001 financial statements.

In addition to SFAS No. 141 and No. 142, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations", in June 2001. This statement establishes accounting standards for the recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This statement is effective for the Company's fiscal year beginning January 1, 2003. In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". This statement addresses financial accounting and reporting for the impairment of long-lived assets and for long-lived assets to be disposed of. This statement is effective for the Company's fiscal year beginning January 1, 2002. Management is currently studying both SFAS No. 143 and No. 144 for their possible impact on the consolidated financial statements when they are adopted.

Issuance of last installment of Special Units to Shell

On or about June 30, 2001, Shell met certain year 2001 performance criteria for the issuance of the last installment of 3.0 million non-distribution bearing, convertible Contingency Units (referred to as Special Units once they are issued). Under a contingent unit agreement with Shell executed as part of the 1999 TNGL acquisition, the Company issued these Special Units on August 2, 2001.

The value of these Special Units was determined to be $117.1 million using present value techniques. This amount increased the purchase price of the TNGL acquisition and the value of the Shell Processing Agreement when the issue was recorded in August 2001. This amount also increased the equity position of Shell in the Company by $117.1 million with the General Partner contributing $1.2 million to maintain its respective ownership in the Company. The $117.1 million increase in value of the Shell Processing Agreement will be amortized over the remaining life of the contract. As a result, amortization expense will increase by approximately $1.6 million per quarter ($6.5 million annually).

In accordance with existing agreements with Shell, 5.0 million of Shell's original issue of Special Units converted into Common Units on August 2, 2001. The issuance of the 3.0 million new Contingency Units had a impact on diluted earnings per Unit beginning with the third quarter of 2001. Likewise, the conversion of the 5.0 million Special Units into Common Units had a impact on basic earnings per Unit beginning in the same quarter.

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, this consolidated 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. During September 2001, the Trust purchased an additional 201,600 Common Units at a cost of $8.8 million. The Trust Units are considered outstanding and will receive distributions; however, they are excluded from the calculation of earnings per Unit.

In September 2001, the Board of Directors of the General Partner approved a modification to the Company's 1,000,000 Unit buy-back program. This two-year program, announced in July 2000, originally allowed the Company to repurchase and retire up to 1,000,000 of its publicly-owned Common Units. Management's intent under the buy-back program 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. As of December 31, 2000, the Company had repurchased and retired 28,400 of these Common Units. The Board of Directors approved a modification to the plan that allows both the Company and the Trust to repurchase Common Units under the buy-back program. Under the terms of the modification, purchases made by the Company will continue to be retired whereas purchases made by the Trust will remain outstanding and not be retired.

As of September 30, 2001, 770,000 publicly-owned Common Units could be repurchased under the buy-back program. Purchases made by the Company will be funded by increased cash distributions from the Operating Partnership's operating cash flows and borrowings under its bank credit facilities. Purchases made by the Trust will be funded by cash contributions from the Operating Partnership arising from similar sources.

Response to September 11, 2001 Terrorist Attacks

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

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The Company is exposed to financial market risks, including changes in commodity prices in its natural gas and NGL businesses and in interest rates with respect to a portion of its debt obligations. The Company may use 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 financial instruments for speculative (trading) purposes.

Commodity Price Risk

The Company's Processing and Octane Enhancement segments are directly exposed to commodity price risk through their respective business operations. The prices of natural gas, NGLs and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond the Company's control. These factors include the level of domestic oil, natural gas and NGL production and development, the availability of imported oil and natural gas, actions taken by foreign oil and natural gas producing nations, the availability of transportation systems with adequate capacity, the availability of alternative fuels and products, seasonal demand for oil, natural gas and NGLs, conservation, the extent of governmental regulation of production and the overall economic environment.

In order to manage this risk, the Company may enter into swaps, forwards, commodity futures, options and other commodity financial instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument. The primary purpose of these risk management activities is to hedge exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions in the Company's Processing segment. As an ancillary service, Acadian Gas utilizes commodity financial instruments to manage the sales/purchase price of natural gas for certain of its customers.

The Company has adopted a commercial policy to manage its exposure to the risks generated by its natural gas and related NGL businesses. The objective of this policy is to assist the Company in achieving its profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by the General Partner. The Company enters into risk management transactions to manage price risk, basis risk, physical risk, or other risks related to its commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 18 months. The General Partner oversees the strategies of the Company associated with physical and financial risks (such as those mentioned previously), 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.

The Company assesses the risk of its commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis performed on this portfolio measures the potential gain or loss in earnings (i.e., the change in fair value of the portfolio) based on a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the dates noted within the table. The sensitivity analysis model takes into account the following primary factors and assumptions:

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

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

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

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

The Company routinely reviews its open commodity financial instruments in light of current market conditions. If market conditions warrant, some instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, the Company may enter into new commodity financial instruments to reestablish the hedge of the commodity position to which the closed instrument relates.

Under the guidelines of SFAS No. 133, as amended and interpreted, a hedge is normally regarded as effective if, among other things, at inception and throughout the life of the hedge, the Company could expect changes in the fair value of the hedged item to be almost fully offset by the changes in the fair value of the hedging instrument. Currently, the Company's commodity financial instruments do not qualify as effective hedges under the guidelines of SFAS No. 133, with the result being that changes in the fair value of these financial instruments are recorded on the balance sheet and in earnings through mark-to-market accounting. The use of mark-to-market accounting for the commodity financial instruments portfolio results in a degree of non-cash earnings volatility that is dependant upon changes in the underlying commodity prices. Even though the commodity financial instruments do not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133, the Company views these financial instruments as hedges inasmuch as this was the intent when such contracts are executed. This characterization is consistent with the actual economic performance of the contracts to date and the Company expects these financial instruments to continue to mitigate commodity price risk in the future. For additional information regarding commodity financial instruments, see Note 10 of the Notes to Unaudited Consolidated Financial Statements.

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

		December 31, 2000	September 30, 2001	November 9, 2001
		(in millions of dollars)		
FV assuming no change in quoted market prices,	Asset (Liability)	$(38.6)	$ 32.2	$ 13.6
FV assuming 10% increase in quoted market prices,	Asset (Liability)	$(56.3)	$ 13.0	$ 1.5
EI assuming 10% increase in quoted market prices,	Income (Loss)	$(17.7)	$ (19.2)	$(12.1)
FV assuming 10% decrease in quoted market prices,	Asset (Liability)	$(20.9)	$ 51.5	$ 25.7
EI assuming 10% decrease in quoted market prices,	Income (Loss)	$ 17.7	$ 19.3	$ 12.1

The fair value of the commodity financial instruments at December 31, 2000 was estimated at $38.6 million payable. On September 30, 2001, the fair value of the commodity financial instruments outstanding was estimated at $32.2 million receivable. The change in fair value between December 31, 2000 and September 30, 2001 was primarily due to lower natural gas prices, settlement of certain open positions and a change in the composition of commodities hedged. On November 9, 2001, the fair value of the commodity financial instruments was $13.6 million receivable primarily due to an increase in quoted market prices since September 30, 2001.

Historical gains or losses resulting from these hedging activities are a component of the Company's operating costs and expenses as reflected in its Statements of Consolidated Operations.

Interest rate risk

Variable-rate Debt. At September 30, 2001 and 2000, the Company had no variable rate debt outstanding and as such had no financial instruments in place to cover any potential interest rate risk on its variable-rate debt obligations. Variable-rate debt obligations do expose the Company to possible increases in interest expense and decreases in earnings if interest rates were to rise.

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"). The objective of holding interest rate swaps is to manage debt service costs by effectively converting a portion of the fixed-rate debt into variable-rate debt. An interest rate swap, in general, requires one party to pay a fixed-rate on the notional amount while the other party pays a floating-rate based on the notional amount. Management believes that it is prudent to maintain a balance between variable-rate and fixed-rate debt.

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

The interest rate swaps outstanding at December 31, 2000 reflected a notional amount of $154 million of fixed-rate debt with the fair value of swaps estimated at $2.5 million. By September 30, 2001, the notional amount had been reduced to $104 million due to the early termination of one of the swaps by a counterparty with the aggregate fair value of the remaining swaps estimated at $9.5 million. The change in fair value between December 31, 2000 and September 30, 2001 is related to lower interest rates and the decision by one counterparty not to exercise its early termination right.

In October 2001, the Company and the counterparty to the swap related to the $350 Million Senior Notes executed the early settlement of this swap. As a result, the Company realized $4.7 million of the $7.3 million in non-cash mark-to-market income recognized through September 30, 2001 relating to its interest rate swaps. Primarily due to this early termination, the fair value of the interest rate swap portfolio was $4.1 million receivable on November 9, 2001.

The Company's interest rate swap agreements were dedesignated as hedging instruments after the adoption of SFAS No. 133; therefore, the interest rate swap agreements are accounted for on a mark-to-market basis.

However, these financial instruments continue to be effective in achieving the risk management activities for which they were intended. As a result, the change in fair value of these instruments will be reflected on the balance sheet and in earnings (interest expense) using mark-to-market accounting. For additional information regarding the interest rate swaps, see Note 10 of the Notes to Unaudited Consolidated Financial Statements that are part of this Form 10-Q quarterly report.

Other. At September 30, 2001 and December 31, 2000, the Company had $67.1 million and $60.4 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.

Counterparty risk

The Company has credit risk from its extension of credit for sales of products and services, and has credit risk with its counterparties in terms of settlement risk associated with its financial instruments. On all transactions where the Company is exposed to credit risk, the Company analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of these limits on an ongoing basis. The counterparty to a majority of the Company's commodity financial instruments is a major Houston, Texas-based energy company. The credit risk to this party is somewhat mitigated by cash or letters of credit held by the Company in an amount dependent upon the exposure with the counterparty.

Related Accounting Developments

Due to the complexity of SFAS No. 133, the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, the initial conclusions reached by the Company regarding the application of SFAS No. 133 upon adoption may be altered. As a result, additional SFAS No. 133 transition adjustments may be recorded in future periods as the Company adopts new FASB interpretations. For additional information regarding SFAS No. 133, see Note 10 of the Notes to Unaudited Consolidated Financial Statements.

PART II. OTHER INFORMATION

Item 2. Use of Proceeds

The following table shows the Use of Proceeds from the $450 Million Senior Notes offering completed on January 29, 2001. The $450 Million Senior Notes represented a takedown of the remaining shelf availability under the Company's December 1999 Registration Statement filed with the Securities and Exchange Commission (File Nos. 333-93239 and 333-93239-01, effective January 14, 2000).

The title of the registered debt securities was "7.50% Senior Notes Due 2011." The underwriters of the offering were Goldman, Sachs and Co., Salomon Smith Barney Inc., Banc One Capital Markets, Inc., First Union Securities, Inc., Scotia Capital (USA) Inc. and Tokyo-Mitsubishi International plc. The 10-year Senior Notes have a maturity date of February 1, 2011 and bear a fixed-rate interest coupon of 7.50%.

	Amounts (in millions)
Proceeds:	
Sale of $450 Million Senior Notes to public at 99.937% per Note	$ 450
Less underwriting discount of 0.650% per Note	(3)
Total proceeds	$ 447
Use of Proceeds:	
Initial payment to finance Acadian Gas acquisition	$(226)
To finance investment in various Gulf of Mexico natural gas pipelines	(112)
To finance remainder of the costs to construct certain NGL pipelines and related projects, and for working capital and other general Company purposes	(109)
Total uses of funds	$(447)

The initial $226 million payment to Shell for Acadian Gas was made in April 2001, subject to certain post-closing purchase price adjustments. Also, the Company paid EPE $112 million in January 2001 for the purchase of equity interests in four Gulf of Mexico natural gas pipeline systems (Starfish, Ocean Breeze, Neptune and Nemo).

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

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

*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 by and among Tejas Energy LLC, Tejas Midstream Enterprises, LLC, Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products Company, Enterprise Products GP, LLC and EPC Partners II, Inc. dated September 17, 1999. (The Company incorporates by reference the above document included as Exhibit "B" to the Schedule 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 among Enterprise Products Operating L.P. and First Union National Bank, as administrative agent; Bank One, NA, as documentation agent; and The Chase Manhattan Bank, as syndication agent and the Several Banks from time to time parties thereto dated November 17, 2000. (Exhibit 4.3 on Form 8-K filed January 25, 2001).

*4.9 Guaranty Agreement (relating to the $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).

*4.12 First Amendment to $250 million Multi-Year Revolving Credit Agreement dated April 19, 2001.

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

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

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

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

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

*10.6 Amended and Restated MTBE Off-Take Agreement between Belvieu Environmental Fuels and Sun Company, Inc. (R and 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 among Enterprise Products Company, Texaco Producing Inc., El Paso Hydrocarbons Company and Champlin Petroleum Company dated July 17, 1985. (Exhibit 10.10 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 8, 1998).

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

*10.10 Amendment to Propylene Facility and Pipeline 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 among Tejas Natural Gas Liquids, LLC and Shell Oil Company, Shell Exploration and Production Company, Shell Offshore Inc., Shell Deepwater Development Inc., Shell Land and Energy Company and Shell Frontier Oil and Gas Inc. dated August 1, 1999. (Exhibit 10.14 to Form 10-Q filed on November 15, 1999).

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

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

(b) Reports on Form 8-K

No Form 8-K reports were filed during the quarter ending September 30, 2001.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

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

/s/ Michael J. Knesek

Vice President, Controller and
Principal Accounting Officer

Date: November 13, 2001