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 June 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 51,524,515 Common Units outstanding as of August 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

Enron	Enron North America Corp. 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	June 30, 2001 (Unaudited)	December 31, 2000
Current Assets		
Cash and cash equivalents (includes restricted cash of $7,321 at June 30, 2001)	$ 123,279	$ 60,409
Accounts receivable - trade, net of allowance for doubtful accounts of $17,032 at June 30, 2001 and $10,916 at December 31, 2000	383,680	409,085
Accounts receivable - affiliates	9,011	6,533
Inventories	99,783	93,222
Prepaid and other current assets	79,260	12,107
Total current assets	695,013	581,356
Property, Plant and Equipment, Net	1,232,792	975,322
Investments in and Advances to Unconsolidated Affiliates	414,808	298,954
Intangible assets, net of accumulated amortization of $7,874 at June 30, 2001 and $5,374 at December 31, 2000	90,369	92,869
Other Assets	9,011	2,867
Total	$2,441,993	$1,951,368
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Accounts payable - trade	$ 59,208	$ 96,559
Accounts payable - affiliate	51,266	56,447
Accrued gas payables	353,444	377,126
Accrued expenses	12,804	21,488
Other current liabilities	81,381	34,759
Total current liabilities	558,103	586,379
Long-Term Debt	855,608	403,847
Other Long-Term liabilities	17,260	15,613
Minority Interest	10,318	9,570
Commitments and Contingencies		
Partners' Equity		
Common Units (46,257,315 Units outstanding at June 30, 2001 and December 31, 2000)	565,469	514,896
Subordinated Units (21,409,870 Units outstanding at June 30, 2001 and December 31, 2000)	188,390	165,253
Special Units (16,500,000 Units outstanding at June 30, 2001 and December 31, 2000)	251,132	251,132
Treasury Units acquired by Trust, at cost (267,200 Common Units outstanding at June 30, 2001 and December 31, 2000)	(4,727)	(4,727)
General Partner	10,151	9,405
Accumulated other comprehensive income	(9,711)	
Total Partners' Equity	1,000,704	935,959
Total	$2,441,993	$1,951,368

See Notes to Unaudited Consolidated Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
REVENUES				
Revenues from consolidated operations	$959,397	$592,913	$1,795,712	$1,339,194
Equity income in unconsolidated affiliates	9,050	11,097	11,061	18,540
Total	968,447	604,010	1,806,773	1,357,734
COST AND EXPENSES				
Operating costs and expenses	851,639	546,306	1,629,380	1,219,212
Selling, general and administrative	7,737	7,658	13,905	13,042
Total	859,376	553,964	1,643,285	1,232,254
OPERATING INCOME	109,071	50,046	163,488	125,480
OTHER INCOME (EXPENSE)				
Interest expense	(16,331)	(8,070)	(23,318)	(15,844)
Interest income from unconsolidated affiliates	7	126	31	270
Dividend income from unconsolidated affiliates		2,761	1,632	3,995
Interest income - other	1,479	1,225	5,477	2,706
Other, net	(251)	(62)	(531)	(425)
Other income (expense)	(15,096)	(4,020)	(16,709)	(9,298)
INCOME BEFORE MINORITY INTEREST	93,975	46,026	146,779	116,182
MINORITY INTEREST	(944)	(466)	(1,478)	(1,175)
NET INCOME	$ 93,031	$ 45,560	$ 145,301	$ 115,007
ALLOCATION OF NET INCOME TO:				
Limited partners	$ 91,643	$ 45,104	$ 142,931	$ 113,857
General partner	$ 1,388	$ 456	$ 2,370	$ 1,150
BASIC EARNINGS PER UNIT				
Income before minority interest	$ 1.37	$ 0.68	$ 2.13	$ 1.72
Net income per Common and Subordinated unit	$ 1.35	$ 0.68	$ 2.11	$ 1.71
DILUTED EARNINGS PER UNIT				
Income before minority interest	$ 1.10	$ 0.56	$ 1.72	$ 1.42
Net income per Common, Subordinated and Special unit	$ 1.09	$ 0.56	$ 1.70	$ 1.40

See Notes to Unaudited Consolidated Financial Statements

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

	Six Months Ended June 30,	
	2001	2000
OPERATING ACTIVITIES		
Net income	$145,301	$115,007
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:		
Depreciation and amortization	23,234	18,347
Equity in income of unconsolidated affiliates	(11,061)	(18,540)
Distributions received from unconsolidated affiliates	13,212	14,268
Leases paid by EPCO	5,267	5,270
Minority interest	1,478	1,175
Gain (loss) on sale of assets	(387)	2,303
Changes in fair market value of financial instruments (see Note 10)	(55,880)	
Net effect of changes in operating accounts	(30,569)	57,003
Operating activities cash flows	90,595	194,833
INVESTING ACTIVITIES		
Capital expenditures	(57,090)	(154,246)
Proceeds from sale of assets	563	52
Business acquisitions, net of cash received	(225,665)	
Collection of notes receivable from unconsolidated affiliates		6,519
Investments in and advances to unconsolidated affiliates	(115,282)	(3,040)
Investing activities cash flows	(397,474)	(150,715)
FINANCING ACTIVITIES		
Long-term debt borrowings	449,716	463,818
Long-term debt repayments		(355,000)
Debt issuance costs	(3,125)	(2,759)
Cash dividends paid to partners	(76,112)	(67,639)
Cash dividends paid to minority interest by Operating Partnership	(783)	(690)
Cash contributions from EPCO to minority interest	53	57
Increase in restricted cash	(7,321)	
Financing activities cash flows	362,428	37,787
NET CHANGE IN CASH AND CASH EQUIVALENTS	55,549	81,905
CASH AND CASH EQUIVALENTS, JANUARY 1	60,409	5,230
CASH AND CASH EQUIVALENTS, JUNE 30	$115,958	$ 87,135

See Notes to Unaudited Consolidated Financial Statements

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

	Partners' Equity			
	at June 30, 2001		at June 30, 2000	
	Units	Amount	Units	Amount
Limited Partners				
Balance, beginning of year	84,434	$ 931,281	81,463	$786,250
Net income		142,931		113,857
Leases paid by EPCO		5,213		5,218
Cash distributions		(74,434)		(66,964)
Balance, end of period	84,434	1,004,991	81,463	838,361
Treasury Units	(267)	(4,727)	(267)	(4,727)
General Partner				
Balance, beginning of year		9,405		7,942
Net income		2,370		1,150
Leases paid by EPCO		54		53
Cash distributions		(1,678)		(676)
Balance, end of period		10,151		8,469
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		32,479		
Balance, end of period		(9,711)		
Total Partners' Equity	84,167	$1,000,704	81,196	$842,103

	Comprehensive Income For Six Months Ended	
	at June 30, 2001	at June 30, 2000
Net Income	$145,301	$115,007
Less: Accumulated Other Comprehensive Loss	(9,711)	
Comprehensive Income	$135,590	$115,007

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 June 30, 2001 and consolidated results of operations, cash flows, partners' equity and comprehensive income for the three and six month periods ended June 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 reporting period. Actual results could differ from those estimates.

The results of operations for the three and six month periods ended June 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 earnings 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 June 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.
- K/D/S Promix LLC ("Promix") - a 33.33% interest in a NGL fractionation facility and related storage facilities located in south Louisiana. The Company's investment includes excess cost over the underlying equity in the net assets of Promix of $8.0 million which is being amortized using the straight-line method over a period of 20 years. The unamortized balance of excess cost over the underlying equity in the net assets of Promix was $7.2 million at June 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") - a 19.9% interest in a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina.
- Starfish Pipeline Company LLC ("Starfish") - a 50% interest in 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 ("LLC") 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 being constructed in the Gulf of Mexico offshore Louisiana. The system is scheduled for completion during the third quarter of 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, when completed in the third quarter of 2001, will comprise 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 and Neptune includes excess cost over the underlying equity in the net assets of these entities of $22.7 million which is being amortized using the straight-line method over a period of 35 years (as a pipeline asset). The unamortized balance of excess cost over the underlying equity in the net assets of Ocean Breeze and Neptune was $22.4 million at June 30, 2001. Likewise, the Company's investment in Nemo includes excess cost over the underlying equity in the net assets of $0.8 million which will be amortized using the straight-line method over a period of 35 years (as a pipeline asset) when Nemo becomes operational during the third quarter of 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 per

day 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:

- 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. 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. 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 June 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 LLC owning a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines in Louisiana. This investment is accounted for using the cost method under the Processing segment.

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

	June 30, 2001	December 31, 2000
Accounted for on equity basis:		
Fractionation:		
BRF	$ 30,210	$ 30,599
BRPC	19,638	25,925
Promix	48,214	48,670
Pipeline:		
EPIK	15,467	15,998
Wilprise	8,617	9,156
Tri-States	27,238	27,138
Belle Rose	11,591	11,653
Dixie	38,179	38,138
Starfish	26,763	
Ocean Breeze	960	
Neptune	76,282	
Nemo	10,814	
Evangeline	5,574	
Octane Enhancement:		
BEF	62,261	58,677
Accounted for on cost basis:		
Processing:		
VESCO	33,000	33,000
Total	$414,808	$298,954

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

	For Three Months Ended June 30,		For Six Months Ended June 30,	
	2001	2000	2001	2000
Fractionation:				
BRF	$ 42	$ 208	$ 60	$ 737
BRPC	252	(29)	404	(19)
Promix	1,396	1,546	1,789	3,208
Pipeline:				
EPIK	(172)	178	(1,094)	1,970
Wilprise	85	74	(137)	162
Tri-States	135	843	100	1,521
Belle Rose	29	(30)	(60)	149
Dixie	69		960	
Starfish	1,022		1,973	
Ocean Breeze	12		14	
Neptune	1,095		1,789	
Nemo	1		10	
Evangeline	(149)		(149)	
Octane Enhancement:				
BEF	5,233	8,307	5,402	10,812
Total	$9,050	$11,097	$11,061	$18,540

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 Six Months ended					
	June 30, 2001			June 30, 2000		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Fractionation:						
BRF	$ 7,825	$ 300	$ 350	$ 9,215	$ 2,222	$ 2,284
BRPC	6,833	1,232	1,347		(187)	(65)
Promix	21,343	5,888	5,964	24,726	10,141	10,255
Pipeline:						
EPIK	1,967	(1,782)	(1,725)	12,972	3,884	3,981
Wilprise	893	(378)	(367)	1,423	470	485
Tri-States	3,953	262	299	7,247	4,470	4,562
Belle Rose	554	(205)	(192)	1,266	366	366
Dixie (a)	24,036	8,301	4,829			
Starfish (b)	13,467	4,390	3,916			
Ocean Breeze (b)	87	87	65			
Neptune (b)	16,747	8,648	8,581			
Nemo (b)		(42)	36			
Evangeline (c)	47,609	1,010	(144)			
Octane Enhancement:						
BEF	113,918	15,922	16,207	137,430	32,373	32,437
Total	$259,232	$43,633	$39,166	$194,279	$53,739	$54,305

Summarized Income Statement data for the Three Months ended

	June 30, 2001			June 30, 2000		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Fractionation:						
BRF	$ 3,802	$ 265	$ 294	$ 4,244	$ 569	$ 648
BRPC	3,400	793	842		(187)	(99)
Promix	12,340	4,447	4,487	12,517	4,752	4,809
Pipeline:						
EPIK	792	(375)	(348)	3,816	324	387
Wilprise	494	224	227	691	212	222
Tri-States	2,321	388	403	3,513	2,490	2,527
Belle Rose	407	13	21	409	(64)	(64)
Dixie (a)	8,799	2,001	1,124			
Starfish (b)	7,051	2,571	2,299			
Ocean Breeze (b)	53	39	39			
Neptune (b)	9,362	5,223	5,195			
Nemo (b)		(27)	2			
Evangeline (c)	47,609	1,010	(144)			
Octane Enhancement:						
BEF	76,054	15,509	15,700	84,097	24,766	24,921
Total	$172,484	$32,081	$30,141	$109,287	$32,862	$33,351

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 2001 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. The cash purchase price is subject to certain post-closing adjustments expected to be completed during the third quarter of 2001 (see below). 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	220,856
Current liabilities	(79,577)
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 June 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 third 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 June 30, 2000 and six month periods ended June 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 six month periods ended June 30, 2000 relating to the Company's equity investments in Starfish, Ocean Breeze and Neptune.

The pro forma information is based upon information currently available to and certain estimates and assumptions by management and, as a result, are not necessarily indicative of the financial results of the Company had the transactions actually occurred on these dates. Likewise, the unaudited pro forma information is not necessarily indicative of future financial results of the Company.

	Three Months Ended	Six Months Ended June 30,	
	June 30, 2000	2001	2000

Revenues	$756,769	$2,018,700	$1,608,252
Income before extraordinary item and minority interest	$ 45,502	$151,063	$ 115,187
Net income	$ 45,041	$149,542	$ 114,022
Allocation of net income to			
Limited partners	$ 44,590	$147,130	$ 112,881
General Partner	$ 450	$ 2,412	$ 1,140
Units used in earnings per Unit calculations			
Basic	66,696	67,667	66,696
Diluted	81,196	84,167	81,196
Income per Unit before minority interest			
Basic	$ 0.68	$ 2.20	$ 1.71
Diluted	$ 0.56	$ 1.77	$ 1.40
Net income per Unit			
Basic	$ 0.67	$ 2.17	$ 1.69
Diluted	$ 0.55	$ 1.75	$ 1.39

4. 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 142 is effective for fiscal years beginning after December 15, 2001 to all goodwill and other intangible assets recognized in an entity's statement of financial position at that date, regardless of when those assets were

initially recognized. The Company is currently evaluating the provisions of SFAS 141 and SFAS 142 and has not adopted such provisions in its June 30, 2001 financial statements.

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

	June 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	2,015	
Less unamortized discount on:		
$350 Million Senior Notes	(135)	(153)
$450 Million Senior Notes	(272)	
Less current maturities of long-term debt		
Long-term debt	$855,608	$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. No amount was outstanding under either of these two revolving credit facilities at June 30, 2001 or December 31, 2000.

At June 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 $19.9 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:

- are subject to a make-whole redemption right;
- are an unsecured obligation and rank equally with existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness; and,
- 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 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.

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

Increase in fair value of fixed-rate debt. Upon adoption of SFAS 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 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). Per a contingent unit agreement with Shell, 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 will increase the purchase price of the TNGL acquisition and the value of the Shell Processing Agreement when the issue is recorded during the third quarter of 2001. 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).

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 six months ended June 30, 2001 and 2000:

	For Three Months Ended June 30,		For Six Months Ended June 30,	
	2001	2000	2001	2000
Income before minority interest	$93,975	$46,026	$146,779	$116,182
General partner interest	(1,388)	(456)	(2,370)	(1,150)
Income before minority interest available to Limited Partners	92,587	45,570	144,409	115,032
Minority interest	(944)	(466)	(1,478)	(1,175)
Net income available to Limited Partners	$91,643	$45,104	$142,931	$113,857
BASIC EARNINGS PER UNIT				
Numerator				
Income before minority interest available to Limited Partners	$92,587	$45,570	$144,409	$115,032
Net income available to Limited Partners	$91,643	$45,104	$142,931	$113,857
Denominator				
Common Units outstanding	46,257	45,286	46,257	45,286
Subordinated Units outstanding	21,410	21,410	21,410	21,410
Total	67,667	66,696	67,667	66,696
Basic Earnings per Unit				
Income before minority interest available to Limited Partners	$ 1.37	$ 0.68	$ 2.13	$ 1.72
Net income available to Limited Partners	$ 1.35	$ 0.68	$ 2.11	$ 1.71
DILUTED EARNINGS PER UNIT				
Numerator				
Income before minority interest available to Limited Partners	$92,587	$45,570	$144,409	$115,032
Net income available to Limited Partners	$91,643	$45,104	$142,931	$113,857
Denominator				
Common Units outstanding	46,257	45,286	46,257	45,286
Subordinated Units outstanding	21,410	21,410	21,410	21,410
Special Units outstanding	16,500	14,500	16,500	14,500
Total	84,167	81,196	84,167	81,196
Diluted Earnings per Unit				
Income before minority interest available to Limited Partners	$ 1.10	$ 0.56	$ 1.72	$ 1.42
Net income available to Limited Partners	$ 1.09	$ 0.56	$ 1.70	$ 1.40

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 $0.5 million and $0.9 million during the three and six months ended June 30, 2001 and none during the same periods in 2000.

On January 17, 2000, the Company declared an increase in its quarterly cash distribution to $0.50 per Unit. This amount was subsequently raised to $0.525 per Unit on July 17, 2000 and $0.55 per Unit on December 7, 2000. On May 3, 2001, the Board of Directors of the General Partner approved an increase in the quarterly distribution rate to $.5875 per Unit beginning with the distribution pertaining to the second quarter of 2001 (payable in August 2001).

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 (through August 13, 2001)	$ 0.5875	$ 0.5875	Jul. 31, 2001	Aug. 10, 2001

9. SUPPLEMENTAL CASH FLOW DISCLOSURE

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

	Six Months Ended June 30,	
	2001	2000
(Increase) decrease in:		
Accounts receivable	$ 96,860	$ 66,374
Inventories	522	(104,477)
Prepaid and other current assets	(10,831)	3,154
Intangible assets		(3,736)
Other assets	(129)	(1,890)
Increase (decrease) in:		
Accounts payable	(55,755)	(64,675)
Accrued gas payable	(78,008)	168,683
Accrued expenses	(11,232)	(11,698)
Other current liabilities	27,817	5,904
Other liabilities	187	(636)
Net effect of changes in operating accounts	$(30,569)	$ 57,003

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 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 six months ended June 30, 2001, the Company recognized a net $55.9 million in non-cash mark-to-market gains related to increases in the fair value of these financial instruments ($52.5 million of this amount was attributable to commodity financial instruments 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 June 30, 2001 per the Statements of Consolidated Cash Flows excludes $7.3 million of restricted cash associated with commodity 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. 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 - Gas Processing and related NGL and natural gas businesses

The Company is exposed to commodity price risk through its natural gas processing and related NGL and natural gas businesses. In order to effectively 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 generated by its gas processing and related NGL and natural gas businesses. The objective of this policy is to assist the Company in achieving its profitability goals while maintaining a portfolio of conservative risk, defined as remaining within the position limits established by the General Partner. The Company 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, 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 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 amounts recorded in Other Comprehensive Income at adoption of SFAS 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 133.

The Company has entered into commodity financial instruments for time periods extending through June 2002. These commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS 133. The Company continues to refer to these financial instruments as hedges in as much as this was the intent when such contracts were executed. This characterization is consistent with the actual economic performance of the contracts and the Company expects these financial instruments to continue to mitigate commodity price risk in the future. The specific accounting for these contracts, however, is consistent with the requirements of SFAS 133. As such, since these contracts do not qualify for hedge accounting under the specific guidelines of SFAS 133, the change in fair value of these commodity financial instruments will be reflected on the balance sheet and in earnings (i.e., mark-to-market accounting treatment).

The following table shows the impact of commodity financial instruments on earnings for the three and six months ended June 30, 2001:

	For the Three Months Ended June 30, 2001	For the Six Months Ended June 30, 2001
End of period non-cash mark-to-market accounting adjustments	$39.0	$52.5
Net Gains (losses) realized on early closeouts and settlements	25.7	17.8
Net gain (loss) recorded in earnings	$64.7	$70.3

Other Financial Instruments - Interest rate swaps

The objective of holding interest rate swaps is to manage debt service costs by 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 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 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 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 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 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 133 will be amortized to earnings over the life of the previously associated debt instrument of approximately 10 years.

Despite the dedesignation of the interest rate swaps, these financial instruments continue to be effective in achieving the risk management objectives for which they were intended. Interest expense for 2001 includes a $5.5 million benefit related to a change in fair value of the Company's interest rate swaps. The change in fair value of the interest rate swaps does not represent a cash gain or loss for the Company. The actual cash gain or loss on the interest rate swap agreements will be based upon market interest rates in effect on the specified settlement dates in the swap agreements. The $5.5 million benefit is primarily due to the decision of one counterparty not to exercise its early termination right under its swap agreement with the Company and, to a lesser extent, lower overall borrowing rates.

Due to the complexity of SFAS 133, the Financial Accounting Standards Board ("FASB") organized a formal committee, the Derivatives Implementation Group ("DIG"), to provide ongoing recommendations to the FASB about implementation issues. Implementation guidance issued through the DIG process is still continuing; therefore, the initial conclusions reached by the Company concerning the application of SFAS 133 upon adoption may be altered. As a result, additional SFAS 133 transition adjustments may be recorded in future periods as the Company adopts new DIG interpretations approved by the FASB.

11. SEGMENT INFORMATION

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

The Company has five reportable operating segments: Fractionation, Pipeline, Processing, Octane Enhancement and Other. The reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by the Chief Executive Officer of the General Partner. Fractionation includes NGL fractionation, butane isomerization (converting normal butane into high purity isobutane) and polymer grade propylene fractionation services. Pipeline consists of 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:							
June 30, 2001	$ 86,566	$178,958	$693,242		$631		$959,397
June 30, 2000	97,004	16,914	478,244		751		592,913
for six months ended:							
June 30, 2001	176,245	186,145	1,432,011		1,311		1,795,712
June 30, 2000	188,901	23,926	1,125,101		1,266		1,339,194
Intersegment revenues							
for three months ended:							
June 30, 2001	44,133	24,631	131,657		96	$(200,517)	
June 30, 2000	47,264	14,826	139,654		94	(201,838)	
for six months ended:							
June 30, 2001	85,785	45,410	241,966		191	(373,352)	
June 30, 2000	82,729	28,025	281,885		188	(392,827)	
Equity income in unconsolidated affiliates							
for three months ended:							
June 30, 2001	1,692	2,125		$5,233			9,050
June 30, 2000	1,725	1,065		8,307			11,097
for six months ended:							
June 30, 2001	2,253	3,406		5,402			11,061
June 30, 2000	3,926	3,802		10,812			18,540
Total revenues							
for three months ended:							
June 30, 2001	132,391	205,714	824,899	5,233	727	(200,517)	968,447
June 30, 2000	145,993	32,805	617,898	8,307	845	(201,838)	604,010
for six months ended:							
June 30, 2001	264,283	234,961	1,673,977	5,402	1,502	(373,352)	1,806,773
June 30, 2000	275,556	55,753	1,406,986	10,812	1,454	(392,827)	1,357,734
Gross operating margin by segment							
for three months ended:							
June 30, 2001	32,803	24,696	68,112	5,233	411		131,255
June 30, 2000	29,591	14,192	18,486	8,307	872		71,448
for six months ended:							
June 30, 2001	58,471	42,819	96,510	5,402	946		204,148
June 30, 2000	63,922	28,827	58,040	10,812	1,426		163,027
Segment property at:							
June 30, 2001	357,142	670,311	125,657		7,884	71,798	1,232,792
December 31, 2000	356,207	448,920	126,895		8,942	34,358	975,322
Investments in and advances to unconsolidated affiliates at:							
June 30, 2001	98,062	221,485	33,000	62,261			414,808
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 June 30,		For Six Months Ended June 30,	
	2001	2000	2001	2000
Total segment gross operating margin	$131,255	$71,448	$204,148	$163,027
Depreciation and amortization	(11,793)	(8,754)	(21,822)	(16,878)
Retained lease expense, net	(2,660)	(2,687)	(5,320)	(5,324)
Loss (gain) on sale of assets	6	(2,303)	387	(2,303)
Selling, general and administrative	(7,737)	(7,658)	(13,905)	(13,042)
Consolidated operating income	109,071	50,046	163,488	125,480
Interest expense	(16,331)	(8,070)	(23,318)	(15,844)
Interest income from unconsolidated affiliates	7	126	31	270
Dividend income from unconsolidated affiliates		2,761	1,632	3,995
Interest income - other	1,479	1,225	5,477	2,706
Other, net	(251)	(62)	(531)	(425)
Consolidated income before minority interest	$ 93,975	$46,026	$146,779	$116,182

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

For the Interim Periods ended June 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

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 market forces, (c) operational and systems risks, (d) environmental liabilities that are not covered by indemnity or insurance, (e) the impact of current and future laws and governmental regulations (including environmental regulations) affecting the NGL industry in general, and the Company's operations in particular, (f) loss of a significant customer, (g) the use of financial instruments to hedge commodity and interest rate risks 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, 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 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 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, the Company is exposed to fluctuations in 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 stream. 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 represents a strategic investment 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 Pipeline 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, 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 six months ended June 30, 2001 include three month's impact of the Acadian Gas acquisition and six 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 third 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 offshore Louisiana in the Gulf of Mexico 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, when completed in the fourth quarter of 2001, will comprise 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.

Current Business Environment

The second quarter of 2001 was a period of recovery for the NGL industry. The decline in natural gas prices from the record levels of the first quarter of 2001 resulted in increased NGL extraction rates throughout the industry. Consequently, the Company saw a rebound in NGL volumes available for fractionation and/or transportation.

At the Company's gas processing facilities, equity NGL production volumes increased from the 46 MBPD of the first quarter of 2001 to 63 MBPD in the second quarter of 2001. Natural gas prices, which approached $10 per MMBtu in January 2001, fell to nearly $3 per MMBtu during July 2001. The price of natural gas relative to the price of NGLs plays a major role in gas processing costs since high natural gas prices result in increased fuel and shrinkage costs which may, at times, exceed the value of the NGLs extracted from the gas. The low equity NGL production rate seen in the first quarter was the result of minimal NGL extraction caused by the abnormally high cost of natural gas. As natural gas prices moderated in the second quarter, NGL extraction rates at the Company's processing facilities and those of other industry participants increased, resulting in additional volumes throughout its NGL value chain.

In the second 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 third quarter of 2001, the Company expects that natural gas prices will generally weaken and that NGL prices will stabilize. In light of these expectations, management continues to monitor its commodity financial instruments portfolio due to the volatility of the energy markets. Third quarter equity NGL production is expected to approximate 75 MBPD.

The Company's recently acquired natural gas pipeline businesses (i.e. Acadian Gas and the Gulf of Mexico joint ventures) have experienced strong demand for their services. In response to the long-term expected increase in natural gas demand, many producers have stepped up their drilling activities resulting in an increase in natural gas volumes available for transportation. Producers believe that natural gas demand will increase near-term due to new gas-fired electric generation facilities commencing operations and a rebound in industrial and commercial demand with the moderation of natural gas prices and an improving economy. Conversely, any material downturn in either the domestic or global economy or long-term decrease in natural gas pricing below $2.75 to $3.00 per MMBTU could result in decreased drilling activities. Barring the latter scenario, the Company's natural gas pipelines expect to maintain or grow their current throughput levels for the near term associated with third-party activities, the most significant of which is the start-up of operations at the Shell Brutus field. This field is expected to generate approximately 130 BBtu/d of natural gas throughput volume and 10 MBPD of equity NGL production by the end of 2001.

During the second quarter of 2001, the Company's isomerization services and isobutane merchant business benefited from strong demand for isobutane used in the manufacture of gasoline. The increase in demand stemmed from refiners increasing gasoline production in anticipation of short-term gasoline supply imbalances heading into the summer driving season. In response, the Company's Mont Belvieu isomerization units ran at near full rates during the early part of the second quarter with the isobutane merchant business profiting on strong spot and contract sales. Also, the Company's Houston Ship Channel import facility and related pipeline system experienced significant volume and margin increases as commercial butane imports (used as feedstock for isobutane) were transported to Mont Belvieu to satisfy the demands of increased isobutane production. By the end of the second quarter, isobutane demand returned to more normalized levels as refiners perceived that gasoline supplies had stabilized. As a result, the Company anticipates that its isomerization and related merchant business (along with its import dock and related pipelines) will experience normalized margins and volumes during the third quarter of 2001.

Propylene fractionation margins are slightly less than last year due to continuing weakness in the propylene markets. Management expects prices to stabilize during the third quarter of 2001 with a slight rise expected in the fourth quarter of 2001 due to a strengthening domestic economy and increased propylene demand. The Company's MTBE operations (reported under the Octane Enhancement business segment) experienced healthy margins early in the second quarter of 2001 due to the seasonal surge in gasoline blending requirements from refiners; however, as gasoline supplies and demand have stabilized, MTBE prices and margins have fallen. The

Company expects results from MTBE operations to be near breakeven for the third and fourth quarters of 2001 as a result of this seasonal decrease in prices.

With regards to its major liquids pipelines, the Company expects the 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. EPIK's financial performance is expected to improve significantly over the last half 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 attractive on the world market and EPIK should benefit from a heavy slate of vessel loadings for export.

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 (c)	$4.61	$27.88	$0.33	$0.46	$0.53	$0.63	$0.19

(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) After reaching a high of $9.87 per MMBtu in January 2001, natural gas prices have declined to an average of $3.68 per MMBtu in June 2001.

Results of Operation of the Company

The Company has five reportable operating segments: Fractionation, Pipeline, Processing, Octane Enhancement and Other. Fractionation includes NGL fractionation, butane isomerization (converting normal butane into high purity isobutane) and polymer grade propylene fractionation services. Pipeline consists of 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 six month periods ended June 30, 2001 and 2000 were as follows:

	For Three Months Ended June 30,		For Six Months Ended June 30,	
	2001	2000	2001	2000
Gross Operating margin by segment:				
Fractionation	$ 32,803	$29,591	$ 58,471	$ 63,922
Pipeline	24,696	14,192	42,819	28,827
Processing	68,112	18,486	96,510	58,040
Octane enhancement	5,233	8,307	5,402	10,812
Other	411	872	946	1,426
Gross Operating margin total	131,255	71,448	204,148	163,027
Depreciation and amortization	11,793	8,754	21,822	16,878
Retained lease expense, net	2,660	2,687	5,320	5,324
Loss (gain) on sale of assets	(6)	2,303	(387)	2,303
Selling, general and administrative expenses	7,737	7,658	13,905	13,042
Consolidated operating income	$109,071	$50,046	$163,488	$125,480

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

	For Three Months Ended June 30,		For Six Months Ended June 30,	
	2001	2000	2001	2000
MBPD, Net				
Equity NGL Production	63	72	54	72
NGL Fractionation	202	215	184	217
Isomerization	94	81	82	74
Propylene Fractionation	29	30	30	30
Octane Enhancement	5	5	4	5
Major NGL and Petrochemical Pipelines	519	340	438	350
MMBtu/D, Net				
Natural Gas Pipelines	1,295,370		1,263,039	

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

Revenues, Costs and Expenses and Operating Income. The Company's revenues increased 60% to $968.4 million in 2001 compared to $604.0 million in 2000. The Company's operating costs and expenses increased by 56% to $851.6 million in 2001 versus $546.3 million in 2000. Operating income increased 118% to $109.1 million in 2001 from $50.0 million in 2000. Second quarter 2001 revenues and expenses have primarily been impacted by the acquisition of Acadian Gas and increased merchant business activities. The majority of the increase in operating income for 2001 relates to $39.0 million in non-cash mark-to-market gains relating to the Company's commodity hedging activities.

Fractionation. The Company's gross operating margin for the Fractionation segment increased to $32.8 million in 2001 from $29.6 million in 2000. NGL fractionation margin declined $4.3 million quarter-to-quarter primarily the result of higher energy costs and lower fractionation volumes. NGL fractionation net volumes were 202 MBPD for 2001 compared to 215 MBPD during 2000. With the decline in natural gas prices since February 2001,

NGL fractionation volumes have improved since the first quarter 2001's 165 MBPD rate due to higher liquids extraction rates at gas processing facilities. The 2000 volume is representative of a period when the industry was maximizing NGL production.

The Company's isomerization business posted a $6.7 million increase in margin in 2001 over 2000 levels with isomerization volumes increasing from 81 MBPD in 2000 to 94 MBPD in 2001. The increase in both margin and volume is attributable to a strong isobutane market early in the second quarter of 2001 which led to an increase in demand for the Company's isomerization services. Gross operating margin from propylene fractionation declined by $0.5 million primarily due to moderating prices and a slight decrease in volumes. Propylene fractionation volumes were 29 MBPD in 2001 versus 30 MBPD during the 2000 period.

Pipeline. The Company's gross operating margin for the Pipeline segment was $24.7 million in 2001 compared to $14.2 million in 2000. Of the $10.5 million increase, $5.2 million is attributable to natural gas pipelines (i.e., the newly acquired Acadian Gas and the Gulf of Mexico systems) which benefited from a strong natural gas marketplace. Natural gas pipeline volumes averaged 1,295 BBtu/d on a net basis. Of the Company's liquids-oriented assets, the recently completed Lou-Tex NGL Pipeline added $2.4 million in margin on volumes of 21 MBPD and the Houston Ship Channel import facility and related pipeline system added $3.1 million primarily due to strong imports of commercial butane. Net liquids throughput volumes increased to 519 MBPD in 2001 compared with 340 MBPD in 2000. Of the 179 MBPD increase in net throughput volumes, 143 MBPD is attributable to the higher import activity.

Processing. For the second quarter of 2001, the Processing segment generated gross operating margin of $68.1 million compared to $18.5 million during the same period in 2000. The Processing segment includes the Company's natural gas processing business and related merchant activities. Gross operating margin from natural gas processing plants posted a $44.1 million increase over 2000 levels primarily due to a $59.1 million increase in net hedging gains from $5.6 million in 2000 to $64.7 million in 2001 (see discussion below). The net hedging gains more than offset the effects of lower equity NGL volumes and prices and a rise in energy-related operating costs. The Company's equity NGL production was 63 MBPD for the 2001 quarter versus 72 MBPD for the same period in 2000. Although lower on a quarter-to-quarter basis, equity NGL production for the second quarter of 2001 improved from the 46 MBPD rate of the first quarter of 2001. The improvement is related to the overall decline in natural gas prices that have led processors industrywide to increase NGL recoveries. Gross operating margin from merchant activities in 2001 increased $5.5 million over 2000 primarily due to strong demand for isobutane.

Gross operating margin for the 2001 period includes $64.7 million of net hedging profits resulting from the Company's commodity hedging activities. Of this amount, $39.0 million is attributable to net non-cash mark-to-market gains on the commodity financial instruments that were outstanding at June 30, 2001. 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 its NGL equity production. During the second quarter of 2001, the Company benefited from a decline in natural gas prices relative to its fixed positions. The decline in natural gas prices created gains on the settlement and early closeout of certain positions of approximately $25.7 million. If natural gas prices had not declined to the degree seen during the quarter, a smaller gain or a loss on hedging activities may have resulted offset somewhat by anticipated higher NGL prices. 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 36.

Octane Enhancement. The Company's gross operating margin for Octane Enhancement decreased $3.1 million in the second quarter of 2001 compared with 2000 levels. MTBE production, on a net basis, was 5 MBPD in both 2001 and 2000. The decline in margin is primarily due to lower MTBE prices in 2001 relative to the 2000 period and higher energy costs.

Interest expense. Interest expense for the second quarter of 2001 increased $8.3 million over the same period in 2000. The increase is primarily due to interest associated with the $450 Million Senior Notes issued in January 2001.

Six Months Ended June 30, 2001 compared with Six Months Ended June 30, 2000

Revenues, Costs and Expenses and Operating Income. The Company's revenues increased 29% to $1.8 billion in 2001 compared to $1.4 billion in 2000. The Company's operating costs and expenses increased by 33% to $1.6 billion in 2001 versus $1.2 billion in 2000. Operating income increased 30% to $163.5 million in 2001 from $125.5 million in 2000. Year-to-date 2001 revenues and expenses have increased due to the acquisition of Acadian Gas and increased merchant business activities. In addition year-to-date 2001 expenses have increased due to higher than normal natural gas prices which affects energy-related operating costs at the Company's facilities. The majority of the increase in operating income for 2001 relates to $52.5 million in non-cash mark-to-market gains relating to the Company's commodity hedging activities.

Fractionation. The Company's gross operating margin for the Fractionation segment decreased to $58.5 million from $63.9 million. NGL fractionation margin decreased $14.7 million primarily due to lower processing volumes and higher energy-related operating costs. NGL fractionation net volumes decreased to 184 MBPD for the first six months of 2001 compared to 217 MBPD during the same period in 2000. The decrease is the result of lower 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. NGL fractionation volumes improved to 202 MBPD during the second quarter of 2001 as extraction rates increased and the price of natural gas declined. For the first six months of 2001, gross operating margin from isomerization services increased $11.2 million compared to 2000 primarily due to an increase in volumes and toll processing fees. Isomerization volumes increased to 82 MBPD during the first six months of 2001 versus 74 MBPD during the same period in 2000 due to increased demand for the Company's services. Gross operating margin from propylene fractionation decreased $2.8 million compared to the first six months of 2001 primarily due to higher energy costs and moderating prices. Net propylene fractionation volumes were 30 MBPD for both periods.

Pipeline. The Company's gross operating margin for the Pipeline segment was $42.8 million compared to $28.8 million in 2000. Of the $14.0 million increase, $6.9 million is attributable to natural gas transportation activities (i.e. Acadian Gas and the Gulf of Mexico systems) which benefited from a strong natural gas marketplace in 2001. The Company's recently completed Lou-Tex NGL Pipeline added $5.1 million on volumes of 22 MBPD. In addition, margin on the Company's Lou-Tex Propylene Pipeline for 2001 was $2.9 million higher than 2000 (primarily due to this asset being purchased in March 2000). Strong imports of mixed NGLs (particularly commercial butanes) resulted in a $3.1 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 strong demand for isobutane which occurred between February and May 2001.

Overall, net throughput on the Company's major liquids pipelines improved to 438 MBPD in 2001 versus 350 MBPD in 2000, with 76 MBPD of the increase stemming from increased imports and related pipeline activity along the Houston Ship Channel. Net throughput for the natural gas pipelines averaged 1,263 BBtu/d with Acadian Gas accounting for 725 BBtu/d and the Gulf of Mexico systems for the balance.

Processing. For the 2001 period, the Processing segment generated gross operating margin of $96.5 million compared to $58.0 million in 2000. Gross operating margin from the natural gas processing plants posted a $4.1 million increase over 2000 levels primarily due to a $67.3 million increase in net hedging gains from $3.0 million in 2000 to $70.3 million in 2001 (see discussion below). The net hedging gains more than offset the effects of lower equity NGL volumes and prices and a rise in energy-related operating costs. Equity NGL production averaged 54 MBPD during the 2001 period compared to 72 MBPD during the 2000 period. The 2001 rate of 54 MBPD reflects the very low NGL extraction rates of the first quarter of 2001 (46 MBPD) when natural gas prices were at their peak. As natural gas costs have declined since January 2001, equity NGL production has begun returning to higher levels (63 MBPD during the second quarter of 2001). The 2000 rate reflects a period in which processors were operating facilities at near full extraction rates. Gross operating margin from merchant activities increased $34.4 million over 2000 primarily due to strong demand for propane in the first quarter of 2001 for heating and isobutane in the second quarter of 2001 for refining.

Gross operating margin for the 2001 period includes $70.3 million of net hedging profits resulting from the Company's commodity hedging activities. Of this amount, $52.5 million is attributable to non-cash mark-to-market gains on the commodity financial instruments that were outstanding at June 30, 2001. As discussed earlier under the Processing segment's quarter-to-quarter variance explanation (see Page 30), 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. Of the $70.3 million in net hedging profits, $17.8 million is attributable to realized gains on the settlement and early closeout of certain positions.

Currently, the predominant strategy employed by the Company utilizes natural gas-based commodity financial instruments to hedge future NGL production and sales. This type of hedge is based upon the historical relationship between natural gas and NGL prices. The key factor behind the net hedging gains recognized by the Company is the decline in natural gas prices relative to the fixed natural gas prices found in its commodity financial instrument portfolio. If natural gas prices had not declined to the degree seen during the quarter, a smaller gain or a loss on hedging activities may have resulted which should have been 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 36 and the quarter-to-quarter variance explanation for Processing found on page 31.

Octane Enhancement. The Company's gross operating margin for Octane Enhancement decreased $5.4 million in the first six 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 decline in margin is primarily due to lower MTBE prices in 2001 relative to the 2000 period, higher energy-related operating costs and a prolonged maintenance outage which lasted from December 2000 until February 2001.

Interest expense. Interest expense for 2001 increased $7.5 million over 2000. The increase is attributable to the interest associated with the $450 Million Senior Notes issued in January 2001. Interest expense for 2001 includes a $5.5 million benefit related to a change in fair value of the Company's interest rate swaps. The change in fair value of the interest rate swaps does not represent a cash gain or loss for the Company. The actual cash gain or loss on the interest rate swap agreements will be based upon market interest rates in effect on the specified settlement dates in the swap agreements. The $5.5 million benefit is primarily due to the decision of one counterparty not to exercise its early termination right under its swap agreement with the Company and, to a lesser extent, lower overall borrowing rates.

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 June 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 and 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 acquisition.

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.

Operating, Investing and Financing Cash Flows for the six months ended June 30, 2001 and 2000. Cash flows from operating activities were a $90.6 million inflow for 2001 compared to a $194.8 million inflow 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 working capital. Net income increased $30.3 million in 2001 compared to 2000 due to reasons mentioned previously under "Results of Operation of the Company". Depreciation and amortization increased a combined $4.9 million in 2001 over 2000 primarily due to additional capital expenditures and business acquisitions. The Company received $13.2 million in distributions from its equity method investments in 2001 compared to $14.3 million in 2000. The $1.1 million decrease in distributions is primarily related to a decrease in BEF's earnings due to lower MTBE prices and volumes, lower throughput volumes on the Tri-States pipeline system and processing volumes at Promix attributable to lower NGL extraction rates during the early part of 2001 offset by receipts from the newly acquired Gulf of Mexico natural gas pipelines. Operating cash flow also includes an adjustment for the $55.9 million in non-cash mark-to-market gains related to commodity and interest rate risk hedging activities. 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.

The Company is exposed to various market risks including commodity price risk (primarily through its gas processing and related NGL businesses) and interest rate risk. The Company attempts to manage its price risk by utilizing certain hedging strategies defined elsewhere herein. These risks, however, may entail significant cash outlays in the future that may not be entirely offset by their underlying hedged positions. During 2001, the Company has recognized $70.3 million in net hedging profits related to its commodity hedging portfolio. Of this amount, a net $17.8 million has been realized through settlements and the early closeout of certain positions through June 30, 2001. The remaining $52.5 million represents non-cash mark-to-market gains on commodity financial instruments that remained open at June 30, 2001. When appropriate, the Company may elect to close certain of its commodity financial instruments prior to their contractual settlement dates in order to realize gains or limit losses. As of August 1, 2001, the Company has realized $26.3 million of the $52.5 million in non-cash mark-to-market gains recorded at the end of the second quarter. The realization of the remaining amount depends upon a number of factors including, most notably, the current market price of natural gas on the settlement or closing date relative to the price in the underlying financial instruments. If the price of natural gas rises beyond the hedging positions taken by the Company, it will result in losses rather than gains on its hedging activities. The Company continues to aggressively monitor its commodity hedging portfolio in light of the energy markets. 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" on page 36 and Note 10 of the Notes to Unaudited Consolidated Financial Statements.

Cash used for investing activities was $397.5 million in 2001 compared to $150.7 million in 2000. Cash outflows included capital expenditures of $57.1 million in 2001 versus $154.2 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 $2.7 million in 2001 and $0.5 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 $115.3 million in investments in and advances to unconsolidated affiliates compared to $3.0 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 $362.4 million during 2001 compared to $37.8 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. Distributions to partners and the minority interest increased to $76.1 million in 2001 from $67.6 million in 2000 primarily due to an increase in the quarterly distribution rate.

During the first six months of 2001, the Company has invested $338 million in business acquisitions and the purchase of 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 annual growth objective for 2001: investing $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) allows 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 $238 million to fund expansions and acquisitions. The Company's cash distribution policy provides management with a great deal of financial flexibility in executing its growth strategy.

Future Capital Expenditures. The Company forecasts that $100.7 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 such as the Sorrento to Napoleonville pipeline and Port Arthur to Lake Charles system). In addition, the Company estimates that its share of currently approved capital expenditures in the projects of its unconsolidated affiliates will be approximately $1.1 million for the remainder of 2001.

As of June 30, 2001, the Company had $11.3 million in outstanding purchase commitments attributable to its capital projects. Of this amount, $10.9 million is related to the construction of assets that will be recorded as property, plant and equipment and $0.4 million is associated with capital projects which will be recorded as additional investments in unconsolidated affiliates.

New Texas environmental regulations may necessitate extensive redesign and modification of the Company's Mont Belvieu facilities to achieve the air emissions reductions needed for federal Clean Air Act compliance in the Houston-Galveston area. Until litigation challenging these regulations is resolved, the technology to be employed and the cost for modifying the facilities to achieve enough reductions cannot be determined, and capital funds have not been budgeted for such work. Regardless of the outcome of this litigation, expenditures for emissions reduction projects will be spread over several years, and management believes the Company will have adequate liquidity and capital resources to undertake them. For additional information about this litigation, see the discussion under the topic Clean Air Act--General on page 22 of the Company's Form 10-K for fiscal 2000.

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

	June 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	2,015	
Less unamortized discount on:		
$350 Million Senior Notes	(135)	(153)
$450 Million Senior Notes	(272)	
Less current maturities of long-term debt		
Long-term debt	$855,608	$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. No amount was outstanding under either of these two revolving credit facilities at June 30, 2001 or December 31, 2000.

At June 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 $19.9 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:

o subject to a make-whole redemption right;
o an unsecured obligation and rank equally with existing and future unsecured and unsubordinated indebtedness and senior to any future subordinated indebtedness; and,
o 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 June 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 No. 133 ("SFAS 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 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 142 is effective for fiscal years beginning after December 15, 2001 to all goodwill and other intangible assets recognized in an entity's statement of financial position at that date, regardless of when those assets were initially recognized. The Company is currently evaluating the provisions of SFAS 141 and SFAS 142 and has not adopted such provisions in its June 30, 2001 financial statements.

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 remaining 3.0 million non-distribution bearing, convertible Contingency Units (referred to as Special Units once they are issued). Per a contingent unit agreement with Shell, the Company issued these Special Units on August 2, 2001.

The value of these Special Units was determined to be $117.1 million using persent value techniques. This amount will increase the purchase price of the TNGL acquisition and the value of the Shell Processing Agreement when the issue is recorded during the third quarter of 2001. 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, the Company's amortization expense is expected to increase by approximately $1.6 million per quarter ($6.5 million annually).

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 is exposed to commodity price risk through its natural gas and related NGL businesses. 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, 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 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. As an ancillary service, Acadian Gas utilizes commodity financial instruments to manage the sales 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 of conservative 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, 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 related NGL production;
- 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 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:

- the commodity financial instruments are not closed out in advance of their expected term,
- the commodity financial instruments function effectively as hedges of the underlying risk, and
- 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 a gain 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 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 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 133, the Company views these financial instruments as hedges in as much as this was the intent when such contracts are executed. This characterization is consistent with the actual economic performance of the contracts 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	June 30, 2001	August 7, 2001
		(in millions of dollars)		
FV assuming no change in quoted market prices,	Asset (Liability)	$(38.6)	$ 49.2	$32.7
FV assuming 10% increase in quoted market prices,	Asset (Liability)	$(56.3)	$ 37.4	$24.9
EI assuming 10% increase in quoted market prices,	Gain (Loss)	$(17.7)	$(11.8)	$(7.8)
FV assuming 10% decrease in quoted market prices,	Asset (Liability)	$(20.9)	$ 61.5	$41.2
EI assuming 10% decrease in quoted market prices,	Gain (Loss)	$ 17.7	$ 12.3	$ 8.5

The fair value of the commodity financial instruments at December 31, 2000 was estimated at $38.6 million payable. On June 30, 2001, the fair value of the commodity financial instruments outstanding was estimated at $49.2 million receivable. The change in fair value between December 31, 2000 and June 30, 2001 was primarily due to the lower natural gas prices, settlement of certain open positions and a change in the composition of commodities hedged. By August 7, 2001, the fair value of the commodity financial instruments was $32.7 million reflecting the early closeout of certain positions and changes in natural gas prices since June 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 June 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 following table presents the hypothetical changes in fair values arising from immediate selected potential changes in quoted market prices of the Company's interest rate swaps outstanding at the dates noted within the table. The sensitivity analysis model used to estimate the fair values of the interest rate swaps takes into account the following primary factors/assumptions: (a)current market interest rates (including forward LIBOR rates and current federal funds rate), (b) early termination options exercisable by the counterparty (if the fair value of the swap indicates a receivable) and (c) a liquid market for interest rate swaps. An increase in fair value of the interest rate swaps approximates the gain that would be recognized in earnings if all of the interest rate swaps were settled at the respective balance sheet dates. Conversely, a decrease in fair value of the interest rate swaps would result in the recording of a loss at the respective balance sheet date. The gains or losses resulting from the interest rate hedging activities are a component of the Company's interest expense as reflected in its Statements of Consolidated Operations.

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

		December 31, 2000	June 30, 2001	August 7, 2001
		(Estimates in millions of dollars)		
FV assuming no change in quoted market prices,	Asset (Liability)	$ 2.5	$ 7.1	$ 8.8
FV assuming 10% increase in quoted market prices,	Asset (Liability)	$ 1.9	$ 5.9	$ 7.6
EI assuming 10% increase in quoted market prices,	Gain (Loss)	$(0.6)	$(1.2)	$(1.2)
FV assuming 10% decrease in quoted market prices,	Asset (Liability)	$ 3.1	$ 8.4	$ 9.9
EI assuming 10% decrease in quoted market prices,	Gain (Loss)	$ 0.6	$ 1.3	$ 1.1

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 June 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 $7.1 million. The change in fair value between December 31, 2000 and June 30, 2001 is primarily related to lower interest rates and the decision by one counterparty not to exercise its early termination right. At August 7, 2001, the fair value of the interest rate swaps was estimated at $8.8 million due to lower interest rates.

The Company's interest rate swap agreements were dedesignated as hedging instruments after the adoption of SFAS 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 June 30, 2001 and December 31, 2000, the Company had $123.3 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 and performance risk associated with its commodity financial instruments and interest rate swap agreements. 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 to the counterparty.

Related Accounting Developments

Due to the complexity of SFAS 133, the FASB organized a formal committee, the Derivatives Implementation Group ("DIG"), to provide ongoing recommendations to the FASB about implementation issues. Implementation guidance issued through the DIG process is still continuing; therefore, the initial conclusions reached by the Company concerning the application of SFAS 133 upon adoption may be altered. As a result, additional SFAS 133 transition adjustments may be recorded in future periods as the Company adopts new DIG interpretations approved by the FASB. For additional information regarding SFAS 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.

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

(b) Reports on Form 8-K

The following Form 8-K reports were filed during the quarter ending June 30, 2001:

8-K filed on April 4, 2001. On April 2, 2001, the Company announced that its Operating Partnership had completed the purchase of Acadian Gas from an affiliate of Shell. The effective date of the transaction was April 1, 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: August 13, 2001

FIFTH AMENDMENT TO CONVEYANCE
OF
GAS PROCESSING RIGHTS

Dated as of April 1, 2001

Between
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.

TABLE OF CONTENTS

FIFTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS

THIS FIFTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS (this "Agreement") dated as of April 1, 2001 ("Effective Date") is made by and between Enterprise Gas Processing, LLC ("Processor"), a Delaware limited liability company, on the one hand, and Shell Oil Company ("SOC"), Shell Exploration and Production Company ("SEPCO"), Shell Offshore Inc., individually and as successor in interest by merger to Shell Deepwater Development Inc. and Shell Deepwater Production Inc. ("SOI"), Shell Consolidated Energy Resources Inc. ("SCERI"), Shell Land and Energy Company ("SLEC"), and Shell Frontier Oil and Gas Inc. ("SFOGI"), all Delaware corporations, on the other, the latter eight parties and their respective Affiliates (as defined below), successors and assigns being collectively referred to as "Producer" or "Producers".

RECITALS

A. Effective January 1, 1982, SOI and SOC executed that certain Conveyance of Gas Processing Rights (the "Original Conveyance"), which granted to SOC the right to process SOI's gas sold pursuant to certain identified gas sale contracts.

B. Effective January 1, 1984, SOC assigned its rights under the Original Conveyance to Shell Western EandP Inc. ("SWEPI").

C. Effective January 1, 1992, the Original Conveyance was amended (the "First Amendment") to provide for a different method of calculating the annual compensation to be paid to SOI by SWEPI and to provide that a list of mineral leases, rather than gas sales contracts, to which the Original Conveyance applied, would be updated annually.

D. Effective January 1, 1997, the First Amendment was amended ("Second Amendment") solely with respect to certain mineral leases, the production from which was dedicated for Processing at the Venice Plant of Venice Energy Services Company, L.L.C., to confirm SWEPI's ownership of the Gas Processing Rights for those mineral leases.

E. Effective January 1, 1998, the Second Amendment was amended in its entirety (the "Third Amendment") to (1) recognize and confirm SWEPI's ownership of the Producers' Gas Processing Rights associated with the Equity Gas attributable to the leases listed on Exhibit A to such Third Amendment, including the right to Process Equity Gas, and receive the benefits therefrom, with respect to such leases; (2) confirm that the transfer of such rights to SWEPI was and is binding on Producers as SOI's successors and assigns, and their respective Affiliates, notwithstanding non-compliance by Producer or SWEPI with respect to any provision concerning annual notification requirements of the First Amendment; (3) provide that SWEPI shall be conveyed without further act, the Gas Processing Rights for Equity Gas from any Lease upon the earlier of that point in time (x) when Gas production from such Lease is committed to be transported in an Upstream Pipeline, (y) when such Lease (or unitized portion thereof) begins Gas production to an Upstream Pipeline, or (z) when SWEPI requires a written dedication of Gas Processing Rights for a Lease in connection with SWEPI's efforts to provide Processing capacity for Gas production from such Lease, regardless of whether Exhibit A is thereafter amended to include Leases; and (4) to make such other changes to the Conveyance as specified in the Third Amendment.

F. Effective January 12, 1998, SWEPI assigned to Tejas Holdings, LLC all of its rights under the Third Amendment and Tejas Holdings, LLC subsequently assigned all of such rights to Tejas Natural Gas Liquids, LLC.

G. Effective August 1, 1999, the Third Amendment was amended and, as so amended, restated in its entirety (the "Fourth Amendment") to clarify the respective rights and obligations of the Processor and Producers thereunder.

H. Effective September 30, 1999, Tejas Natural Gas Liquids LLC changed its name to Enterprise Natural Gas Liquids, LLC.

I. Effective October 31, 1999, Enterprise Natural Gas Liquids, LLC merged with and into Enterprise Products Operating L.P., with Enterprise Products Operating L.P. being the surviving entity of such merger.

J. Effective March 31, 2001, Enterprise Products Operating L.P. assigned all of its rights under the Fourth Amendment to its wholly-owned subsidiary, Enterprise Gas Processing, LLC, which assignment is hereby in all respects approved and consented to by Producers.

K. The parties desire to further amend the Fourth Amendment to incorporate certain changes in their respective rights and obligations thereunder and to restate the Conveyance in its entirety.

NOW THEREFORE, in consideration of the mutual agreements, covenants and conditions herein contained, the Parties hereby agree as follows:

1. DEFINITIONS.

1.1 "*Affiliate*" means, with respect to any relevant Person, any other Person that directly or indirectly controls, is controlled by, or is under common control with, such relevant Person in question. As used herein, the term "control" (including its derivatives and similar terms) means owning, directly or indirectly, the power (1) to vote ten percent or more of the voting stock of any such relevant Person and (2) to direct or cause the direction of the management and policies of any such relevant Person.

1.2 "*Annual Information*" has the meaning given it in Section 14.

1.3 "*BTU*" or "*British Thermal Unit*" means the quantity of heat required to raise the temperature of one pound of pure water from 58.5 degrees to 59.5 degrees on the Fahrenheit temperature scale at a constant pressure of 14.73 psia. The term "MMBTU" shall mean 1,000,000 BTU's.

1.4 "*Commitment Date*" has the meaning given it in Section 3.2.

1.5 "*Consideration Basis*" has the meaning given it in Section 6.2.

1.6 "*Conveyance*" means the Original Conveyance described in Recital A, as amended to date and by this Agreement and as hereafter amended from time to time.

1.7 "*Cubic foot of Gas*" shall mean the volume of Gas contained in one cubic foot of space at a standard pressure base of 14.73 pounds per square inch absolute, and at a standard temperature base of 60(degree)F. Whenever the conditions of pressure and temperature differ from the above standard, conversion of the volume from these conditions to the above stated standard conditions shall be made in accordance with the Ideal Gas Laws, corrected for deviation due to supercompressibility by the methods set forth in ANSI/API 2530, as revised or amended from time to time, and further detailed in American Petroleum Institute Manual of Petroleum Measurement Standards (API MPMS) Chapter 14, Section 2, American Gas Association (AGA) Report Number 3, "Compressibility Factors of Natural Gas and Other Related Hydrocarbons," as revised or amended from time to time. The terms "MCF" and "MMCF" shall mean, respectively, 1,000 Cubic Feet of Gas and 1,000,000 Cubic Feet of Gas.

1.8 "*Dedicated*" means, with respect to a Lease, a Lease owned by a Producer as of or after the Commitment Date.

1.9 "*Equity Gas*" means Gas that is produced from a Dedicated Lease and is owned and marketed by, or on behalf of, Producers. Equity Gas shall also include any lessor's royalty Gas that is not taken "in-kind" by lessor and which is marketed by, or on behalf of, Producers. Equity Gas shall exclude the following:

(i) Gas consumed by a Producer in the development and operation of Dedicated Leases, including, but not limited to, the following operations: drilling; deepening; reworking of wells; compression; Gas lift; treating; separation; operationally integrated power generation; maintenance of facilities; and consumed as fuel in such operations.

(ii) Gas provided by a Producer to another operator or producer in the general vicinity of such Producer's operations to be used by such operators or producers for purposes similar to those set forth in (i) above; provided, however, if Gas furnished by Producer is used for such purposes, Producer shall keep Processor whole from an economic standpoint for any volumes that are so used.

(iii) Gas used by a Producer as makeup or non-consent Gas to or for the benefit of third parties as may be required under joint operating, Gas balancing or other similar agreements and produced from wells covered by such agreements or to settle Gas imbalance claims with other mineral and/or leasehold interest owners.

(iv) Gas used by a Producer to make payment of royalty and/or overriding royalty in kind if required in the Dedicated Leases or instruments pursuant to which such royalties and overriding royalties were created, excluding any overriding royalties held by Affiliates of Producer.

(v) Gas which is actually used by pipelines for fuel to transport lease production and/or is otherwise flared, lost or unaccounted for prior to delivery to a Plant.

(vi) Gas which is precluded from being produced or Processed due to governmental intervention, regulations, laws or judicial or administrative orders.

1.10 "*Excludable Gas*" means any Equity Gas that contains less than or equal to one GPM of ethane and heavier hydrocarbons as measured at a Field Delivery Point.

1.11 "*Excluded Lease"* means a Lease listed on Exhibit B.

1.12 "*Field Delivery Point*" means any point at which Gas being transported in Upstream Pipelines is measured for the purpose of allocating PTR and Products from a Plant.

1.13 "*Gallon*" means one U.S. Standard Liquid Gallon of 231 cubic inches, adjusted to a temperature of 60(degree)F and either the equilibrium pressure of the product at 60(degree)F or 14.696 psia, whichever is greater.

1.14 "*Gas*" means all vaporized hydrocarbons and vaporized concomitant materials whether produced from wells classified as oil wells or gas wells.

1.15 "*Gas Processing Rights*" has the meaning given it in Section 3.1.

1.16 "*Geographical Scope*" means that area (i) within the state waters of Louisiana, Texas, Mississippi, Alabama and Florida, (ii) within the federal waters of the United States of America in the Gulf of Mexico, including any portion thereof claimed by Mexico.

1.17 "*GPM*" means Gallons per MCF of Gas.

1.18 *"Injected Liquids*" means liquid hydrocarbons and liquid concomitant materials that are delivered into an Upstream Pipeline.

1.19 "*Lease*" means any oil, Gas, and/or mineral lease or interest therein owned now or hereafter acquired by Producers or their Affiliates within the Geographical Scope excluding any lease listed on Exhibit B.

1.20 "*New Volumes*" has the meaning given it in Section 2.3.2.

1.21 "*Off-Spec Deliveries*" has the meaning given it in Section 5.3.

1.22 "*Person*" means any individual or entity, including, without limitation, any corporation, limited liability company, partnership (general or limited), joint venture, association, joint stock company, trust, unincorporated organization or government (including any board, agency, political subdivision or other body thereof).

1.23 "*Plant*" means a natural gas processing plant.

1.24 "*Plant Delivery Point"* means the point where an Upstream Pipeline interconnects with a Plant.

1.25 "*Plant Redelivery Point"* means the point at or near the tailgate of a Plant at which the Residue Gas is redelivered by a Plant into any interstate or intrastate pipeline connected to that Plant.

1.26 "*Process*" or "*Processing*" means the removal of liquefiable hydrocarbons and/or impurities from Gas using mechanical separation, extraction, condensation, compression, absorption, stripping, refrigeration, adiabatic expansion, and/or other generally accepted natural gas processing methods.

1.27 "*Processor*" means Enterprise Gas Processing, LLC, a Delaware limited liability company, and its successors and assigns.

1.28 "*Processor's Retrograde*" means (i) liquefiable hydrocarbons that condense from Equity Gas in the Upstream Pipelines listed in Exhibit D, and (ii) any liquid hydrocarbons that are collected in the Plant prior to Processing. Processor's Retrograde shall not include Injected Liquids but shall include any lessor's royalty share of such liquefiable hydrocarbons in clauses (i) and (ii) of this definition not taken "in kind" by lessor.

1.29 "*Producer*" means each of those entities listed in the first paragraph of this Agreement and their respective Affiliates, successors and assigns (but as to any such assigns, only to the extent such assigns acquire all or part of a lessee's interest in a Dedicated Lease).

1.30 "*Products*" means the individual liquefied hydrocarbons recovered from Equity Gas and/or Processor's Retrograde by Processing including, but not by way of limitation, condensate, natural gasoline, butanes, propane, ethane, and/or any unfractionated mixture thereof including, in each case, such methane as is liquefied and incidentally recovered.

1.31 "*PTR*" means plant thermal reduction or the heat content stated in MMBTU's removed from the Equity Gas and/or Processor's Retrograde as a result of Processing including those MMBTU's (i) associated with extraction of Products, (ii) consumed in the operation of a Plant, and (iii) flared, lost or otherwise unaccounted for in the operation of a Plant.

1.32 "*Quality Specifications*" has the meaning given it in Section 5.1.

1.33 "*Raw Make*" means a combined stream of liquefied hydrocarbons and concomitant materials extracted from Equity Gas by Processing including Processor's Retrograde if subsequently combined with the other Raw Make.

1.34 "*Residue Gas*" means the portion of Equity Gas remaining after removal of PTR during Processing and available for redelivery to a pipeline at the Plant Redelivery Point.

1.35 "*Slug Liquids*" means free water, liquid hydrocarbons and other concomitant materials which are separated from Gas upstream of the Plant Delivery Point.

1.36 "*Transportation Cost*" means the cost of transportation of PTR from the wellhead to the Plant Delivery Point.

1.37 "*Termination Date*" has the meaning given it in Section 2.2.

1.38 "*Upstream Pipeline*" means any pipeline that transports Gas and/or Slug Liquids between the Field Delivery Points and the Plant Delivery Points.

2. TERM.

2.1 Primary and Successive Terms. The term of this Agreement shall begin on August 1, 1999, and continue for a primary term of 20 years, unless sooner terminated under Section 2.2. At the end of the primary term, the term of this Agreement shall be automatically extended for ten successive two year terms, unless sooner terminated under Section 2.2.

2.2 Termination of Agreement. The Processor or any Producer shall have the right, subject to Section 2.3, to terminate this Agreement as to such Producer at the end of the primary term or at the end of any successive two year term thereafter ("Termination Date") by giving written notice of termination, in accordance with Section 18.6, no sooner than 20 nor later than 18 months prior to the expiration of the then effective primary term or two year successive term.

2.3 Survival Provision.

2.3.1 Post Termination: Continuation as to Committed Leases. Notwithstanding termination of this Agreement pursuant to Section 2.2 above (but not Section 2.4), the Gas Processing Rights held by Processor and all the provisions of this Agreement shall continue in full force and effect with respect to each Dedicated Lease until the expiration of such Dedicated Lease.

2.3.2 Post Termination: Proposals for New Volumes. For a period of 20 years after the Termination Date, as to Leases (other than Dedicated Leases) from which Gas is discovered to be ultimately produced by Producers ("New Volumes"), Producers agree to provide Processor, as soon as reasonably practicable, with notice of the estimated quantity of New Volumes and the estimated date on which such New Volumes will be available for Processing. Producers further agree that they will provide Processor a nonexclusive opportunity to submit a proposal to Process the New Volumes. If, in the sole discretion of the Producer offering the New Volumes, the proposal of Processor is not acceptable, then the Producer will notify Processor of such, without any obligation to disclose terms or conditions of, or differences between, other proposals. The Producer will then enter into negotiations with Processor for no more than a 15-day period in an effort to enter into agreements concerning the New Volumes. If Processor and Producer do not enter into such mutually agreeable Processing agreements within the 15-day period, then Producer shall be free to deliver and/or dedicate said New Volumes, in their sole discretion, and for any purpose, to a third party.

2.4 Early Termination of Entire Agreement Due To Unprofitable Processing.

2.4.1 Right to Terminate. If for any 12-month period, the expenses of Processor incurred in Processing Equity Gas exceed revenues obtained therefrom, then Processor may, at its sole option, terminate this Agreement upon delivery to all Producers of notice to terminate in accordance with Section 18.6. After delivery of such notice, at the written request of Processor or any Producer, the Processor and such Producer shall enter into exclusive good faith negotiations for a period of 90 days from delivery of notice of termination to negotiate the terms and conditions of a mutually agreeable alternative Processing arrangement. If the Processor and Producer are unable to negotiate and execute the definitive agreement for such alternative Processing arrangement within the 90-day period, then any Producer that has not entered into such a definitive agreement shall be free to negotiate and enter into an agreement with any one or more third parties for Processing services; provided, however, that the terms agreed to between such Producer and a potential third party processor for Processing services are, taken as a whole, more favorable to the Producer than the latest terms for Processing services previously offered by Processor to Producer during such 90-day period.

2.4.2 Obligation to Continue Processing. Processor shall continue to process Equity Gas for each Producer until the earlier of (i) 12 months after the expiration of the 90-day period referenced in Section 2.4.1, or (ii) the effective date of the Producer's new third party processing agreement with respect to such Gas. In any such case, if Processor's expenses incurred exceed the revenues obtained through Processing a Producer's Equity Gas in any given month, such Producer shall reimburse Processor on a monthly basis the difference between the Processor's expenses and revenues for such month. Producer shall pay Processor any cash due no later than 60 days following the end of the month in which the Producer's Equity Gas is delivered for Processing.

3. ASSIGNMENT OF GAS PROCESSING RIGHTS.

3.1 Grant of Processing Rights. Subject to the other provisions of this Agreement, Producers hereby grant, sell, transfer, convey and assign to Processor the following (the "Gas Processing Rights"):

(1) the exclusive right to process any and all Equity Gas for the extraction and retention of liquefiable hydrocarbons and other constituents of Raw Make and/or Products;

(2) all title, interest and /or ownership in Raw Make and/or Products recovered from Processing Equity Gas; and

(3) the right and option to assume all economic burdens and to obtain all economic benefits reserved to the Gas producer under a contract for Processing Equity Gas that is assumed by a Producer in connection with the acquisition of a Lease.

It is the intention of the parties to confer on the Processor all of the economic benefits to be derived from Processing all Gas from Leases, whether derived from Leases currently owned and/or Dedicated or Leases subsequently acquired by a Producer and/or subsequently Dedicated, subject only to (i) rights previously granted by the transferors of subsequently acquired Leases to third parties as provided in Section 3.3 and (ii) the right of Producers under Section 3.2 to transfer, free of Processor's rights under this Agreement, Leases that at the time of transfer are not Dedicated Leases.

3.2 Attachment of Gas Processing Rights. This conveyance of Gas Processing Rights shall be irrevocable as to "Dedicated Leases". A Lease shall be considered a Dedicated Lease upon the earliest of that point in time (the "Commitment Date"): when (i) when a well is spud on the Lease; (ii) a Plan of Exploration ("POE") or similar document including all or part of the Lease is submitted or amended to the appropriate regulatory agency and a well is or has been spud on any of the Leases included in the POE; (iii) a Development Operations Coordination Document ("DOCD") or similar document including all or part of the Lease is submitted or amended to the appropriate regulatory agency; or (iv) Gas production begins from the Lease. A Lease acquired by a Producer shall become a Dedicated Lease on the later of (1) the effective date of the acquisition of such Lease by Producer if at any time prior to such acquisition an event occurred that would constitute a Commitment Date had the Producer owned an interest in such Lease at the time of such event, or (2) the later Commitment Date for such Lease. Dedicated Leases as of August 1, 1999 are listed on Exhibit A. Producer shall have the right to transfer, sell, assign, exchange or otherwise alienate a Lease free of any obligations under this Agreement and without any obligation to the Processor with respect to the Lease prior to the Commitment Date with respect to a Lease.

3.3 Producers' Nondisturbance Covenant; Prior Reservations or Contracts. Excepting Producers' rights to sell, assign, exchange or otherwise alienate Leases as provided for in Section 3.2, Producers agree not to make any assignment or conveyance of, or enter into any other obligation concerning Gas Processing Rights with respect to, any Lease to the prejudice of Processor or its rights under this Agreement. Producers further agree that, in connection with the acquisition of a Lease, they will not permit the transferor to reserve to itself or convey to any person any right to Process Equity Gas to be produced from the Lease. However, as to any Lease acquired by a Producer subject to a prior grant of rights to Process Equity Gas to be produced under the Lease to Persons other than a Producer, Processor's rights under this Agreement shall be subject to such rights previously granted, to the extent thereof.

3.4 Processor's Right to Consume PTR. In conveying the Gas Processing Rights under this Agreement, Producers acknowledge and agree that the Equity Gas Processed in a Plant will be subject to a PTR incidental to the exercising of the Gas Processing Rights, and Producers hereby grant to Processor the rights to consume Equity Gas as PTR associated with Processor's Retrograde and Products.

3.5 Title to Raw Make, Products, Processor's Retrograde and PTR. Producers hereby (i) represent and warrant to Processor that title to the liquefiable hydrocarbons in Equity Gas is and will be free from all production burdens, liens and adverse claims, (ii) warrant their right to sell the same and (iii) agree to indemnify, defend and hold harmless Processor against all claims to said liquefiable hydrocarbons arising (x) by, through, or under Producers or (y) prior to Producers' delivery of said liquefiable hydrocarbons to Processor. The transfer of title to, and risk of loss for, the extracted liquefiable hydrocarbons shall pass to Processor at the meters for Raw Make and/or Products, as appropriate, of the applicable Plant. As between the parties, Producers shall be deemed to be in exclusive control and possession of the liquefiable hydrocarbons prior to such transfer of title to Processor. The Processor and Producers acknowledge and agree that title to PTR does not pass to Processor.

3.6 Limitations on Upstream Processing.

3.6.1 Producer's Operational Requirements. Producers agree that, except as dictated by operational requirements, including the need to meet pipeline specifications, they will not remove or permit to be removed any liquefiable hydrocarbons from Equity Gas upstream of the Plants except for liquefiable hydrocarbons that condense from the gas during transportation to the Plants.

3.6.2 Processor's Exclusive Rights. The rights granted to Processor herein are exclusive, and Producers shall use their commercially reasonable efforts to ensure that no owner or operator of an Upstream Pipeline shall have or exercise any right or opportunity to Process, or extract Products from, Equity Gas as to which the Gas Processing Rights have been conveyed to Processor under this Agreement.

3.7 NGL Banks. In the event that any Upstream Pipeline or the shippers on an Upstream Pipeline institute a bona fide mechanism to mitigate inequities that may occur between shippers on such Upstream Pipeline as a result of such shippers' Gas streams containing different liquifiable hydrocarbon compositions being commingled in a pipeline with multiple delivery points located upstream of Gas Processing Plants (an "NGL Bank"), Producers and Processor agree to participate in the NGL Bank so as to confer on Processor the financial benefits and detriments related to such liquifiable hydrocarbons under the terms of the NGL Bank. Producers and Processor agree to execute and deliver to one another such instruments as may be necessary or useful and to take such further actions as may be reasonably necessary to carry out or further evidence the intent of this Section 3.7. Pending execution of such instruments, Producers shall not be required to curtail any Equity Gas production. However, Producers shall ensure Processor receives all financial benefits and detriments referenced in this Section 3.7 from the date of initiation of the NGL Bank.

4. PROCESSOR'S OBLIGATION TO PROCESS AND REDELIVER; LIMITATIONS.

4.1 Processor's Obligation to Process and Redeliver Residue Gas. Subject to the provisions of this Agreement, throughout the term of this Agreement and for any subsequent period of time as contemplated by Section 2.3.1, Processor agrees to Process, or cause to be Processed, all Equity Gas. After Processing Equity Gas and/or Slug Liquids and the recovery of the Raw Make, Products and Processor's Retrograde therefrom, Processor shall deliver or cause to be delivered Producers' Residue Gas to Producers or Producers' designee at the applicable Plant Redelivery Point.

4.2 Temporary Cessation of Processing. If at any time or from time to time Processor reasonably determines that the temporary cessation of Processing Equity Gas at a Plant would not cause curtailment of the applicable Equity Gas, then Processor shall have the option, in its sole discretion, to temporarily cease Processing at that Plant. Processor shall provide Producer with at least two business days' notice of any such election to temporarily cease Processing or to subsequently recommence Processing at a Plant and shall not change its election more than two times in a month.

4.3 Refused Volumes.

4.3.1 Insufficient Capacity; Option to Refuse Volumes. Processor may, at its option, elect not to Process a volume of Equity Gas that exceeds its available Processing capacity at a Plant ("Refused Volumes") and agrees to provide the applicable Producer with notice of such election as soon as reasonably practicable. If Processor elects not to Process such Refused Volumes, Producer may, nonetheless, by written notice to Processor, require that Processor and Producer enter into exclusive good faith negotiations for a period of 90 days from the date of the notice to negotiate the terms and conditions of a mutually agreeable alternative Processing arrangement for the Refused Volumes that would allow Processor in its sole judgment to economically acquire or construct additional capacity at the Plant. If within the 90-day period Processor and Producer are unable to negotiate and execute such a definitive agreement, then Producer shall be free to negotiate with any third party for Processing services for the Refused Volumes for a primary terms not to exceed one year and Processor shall have no further obligation to negotiate with Producer. In any event, Processor shall have no obligation to acquire or construct new capacity. Producers shall make a reasonable effort to deliver Equity Gas to Upstream Pipelines that will subsequently deliver it to Plants in which Processor has sufficient capacity to Process such Equity Gas.

4.3.2 Option to Reacquire Refused Volumes. Processor shall have the option, exercisable by three months' written notice to the Producers, to acquire the right to Process such Refused Volumes beginning on any anniversary date of the third party agreement and may do so without prejudice to subsequent exercise of its rights under Section 4.3.1.

4.4 Excludable Gas.

4.4.1 Option to Exclude Certain Gas. Processor may, at its option, elect to not Process all or any part of Equity Gas that contains less than or equal to one GPM of ethane and heavier hydrocarbons as measured at a Field Delivery Point ("Excludable Gas") and agrees to provide the applicable Producer with notice of such election as soon as reasonably practicable. If Processor elects not to Process such Excludable Gas, a Producer may, nonetheless, by written notice to Processor, require that Processor and Producer enter into exclusive good faith negotiations for a period of 90 days from the date of the notice to negotiate the terms and conditions of a mutually agreeable alternative Processing arrangement for the Excludable Gas. If within the 90-day period Processor and Producer are unable to negotiate and execute a definitive agreement related thereto, then Producer shall be free to negotiate with any third party for Processing services for the Excludable Gas for a primary term not to exceed one year and Processor shall have no further obligation to negotiate with Producer.

4.4.2 Terms of Continued Processing Pending Third Party Contract. Upon the written request of a Producer, Processor shall continue to Process such Producer's Excludable Gas until the earlier of (i) 12 months after the expiration of the 90-day period referenced in Section 4.4.1, or (ii) the effective date of the new third party Processing agreement. In any such case, if Processor's expenses incurred exceed revenues obtained from Processing a Producer's Excludable Gas in any given month during that period of time, such Producer shall reimburse Processor on a monthly basis the difference between the Processor's expenses and revenues for such month. Producer shall pay Processor any cash due no later than 60 days following the end of the month in which the Producer's Excludable Gas is delivered for Processing.

4.4.3 Option to Reacquire Excludable Gas. Processor shall have the option, exercisable by three months' written notice to the Producers, to acquire the right to Process any Excludable Gas under this Agreement beginning on any anniversary date of the third party agreement and may do so without prejudice to subsequent exercise of its rights under Section 4.4.1.

4.5 Unprofitable Plant.

4.5.1 Right to Close Unprofitable Plant. If for any 12-month period, expenses of operating one or more Plants that Process Equity Gas exceed revenues obtained from Processing, then Processor shall have the right, upon at least 90 days' prior written notice to all affected Producers in accordance with Section 18.6, to elect to shut down any such Plant for a continuous period of at least one year and, if such Equity Gas cannot be delivered to another Plant, to exclude the Equity Gas delivered to the shut down Plant from this Agreement. After delivery of such notice, at the written request of Processor or any Producer, the Processor and Producer shall enter into exclusive good faith negotiations for a period of 90 days from delivery of such notice to negotiate the terms and conditions of a mutually agreeable alternative Processing arrangement for the Equity Gas delivered to the Plant that would allow the Plant to remain profitable. If the Processor and Producer are unable to negotiate and execute the definitive agreement for such alternative Processing arrangement within the 90-day period, then any Producer that has not entered into such a definitive agreement shall be free to negotiate and enter into an agreement with any one or more third parties for Processing services; provided, however, that the terms agreed to between such Producer and a potential third party processor for Processing services are, taken as a whole, more favorable to the Producer than the latest terms for Processing services previously offered by Processor to Producer during such 90-day period. The parties shall promptly amend Exhibit B to include among Excluded Leases any Lease that is excluded from this agreement under the terms of this Section 4.5.1.

4.5.2 Terms of Continued Processing. Upon the written request of a Producer, Processor shall continue to process such Equity Gas at the Plant for a period of time not to exceed 12 months after the expiration of the 90-day period referenced in Section 4.5.1. In any such case, if Processor's expenses incurred exceed the revenues obtained through Processing such Producer's Equity Gas in any given month during that period of time, such Producer shall reimburse Processor on a monthly basis the difference between the Processor's expenses and revenues for the month. Producer shall pay Processor any cash due no later than 60 days following the end of the month in which the Equity Gas is delivered for Processing.

4.6 Suspension in Case of Dangerous Condition. If any of Producer's operations or any of the Equity Gas or Slug Liquids delivered hereunder create a condition that, in the exclusive judgment of Processor, may endanger the Plant or property of Processor or the lives or property of Processor's employees or any third party, Processor may, without liability, immediately discontinue receipt of Equity Gas and/or Slug Liquids, as the case may be, until the condition has been remedied to the reasonable satisfaction of Processor.

5. SPECIFICATIONS FOR GAS AND SLUG LIQUIDS.

5.1 Quality Specifications. Producers shall deliver Equity Gas and Injected Liquids to each Field Delivery Point in conformity with the specifications of the applicable Upstream Pipeline (the "Quality Specifications").

5.2 Testing. The determination as to the conformity of Equity Gas or Injected Liquids to the Quality Specifications shall be made by Processor in accordance with generally accepted procedures of the gas processing industry. Such determinations shall be made as often as Processor deems necessary, and Producer may witness such determinations or make joint determinations with its own appliances. If, in Producer's judgment, the result of any such test or determination is inaccurate, Processor, at Producer's request, will again conduct the questioned test or determination, and the costs of such additional test or determination shall be borne by Producer unless same shows the original test or determination to be materially inaccurate.

5.3 Off-Spec Deliveries. If any of Equity Gas or Injected Liquids delivered at a Field Delivery Point fail to meet the Quality Specifications ("Off-Spec Deliveries"), Processor, subject to the provisions of Sections 5.4, 5.5 and 5.6, at its sole option, may accept, or notify the appropriate Producer to discontinue or curtail, such Off-Spec Deliveries. Processor's acceptance of Off-Spec Deliveries shall not be deemed a waiver of Processor's right to later reject such Off-Spec Deliveries, nor shall acceptance of Off-Spec Deliveries from one Field Delivery Point require Processor to accept similar Off-Spec Deliveries from any other Field Delivery Point.

5.4 Notification of Non-Conformity; Rejection of Delivery. Processor shall notify a Producer of any Off-Spec Deliveries, and Producer shall make a diligent effort to conform such Equity Gas and/or Injected Liquids to the Quality Specifications. If any Producer reasonably concludes that it cannot economically deliver Equity Gas and/or Injected Liquids conforming to the Quality Specifications, then such Producer shall so advise Processor in writing within 30 days after receipt of Processor's notice. Within 30 days after receipt of Producer's notice, Processor shall give notice to the Producer in writing of its election to accept or reject such Off-Spec Deliveries. If Processor rejects such Off-Spec Deliveries, then upon receipt of said notice by such Producer, this Agreement will be suspended with respect to the Field Delivery Points with such Off-Spec Deliveries until such time as the Off-Spec Deliveries conform to the Quality Specifications or Processor subsequently notifies such Producer of its acceptance of the Off-Spec Deliveries.

5.5 Acceptance of Nonconforming Product. If Processor accepts such Off-Spec Deliveries, Processor, after written notice to Producers as specified in Section 5.4, may charge Producers any reasonable costs incurred by Processor to monitor the quality of Equity Gas and/or Injected Liquids and bring them within the Quality Specifications. Processor shall invoice Producer on a monthly basis for any such costs, the payment of which shall be due and payable within 30 days after Producer's receipt thereof.

5.6 Processor's Limited Commitment to Accept Non-Conforming Product. Notwithstanding the provisions of Sections 5.3, 5.4 and 5.5, Processor agrees that it will use reasonable efforts to continue acceptance of a Producer's Off-Spec Deliveries for Processing in those cases where (i) Section 4.6 does not apply and (ii) the acceptance of such Off-Spec Deliveries does not (x) cause damage to the Plant, (y) render the Plant unable to meet applicable specifications of the pipelines receiving Residue Gas at the Plant Redelivery Points or of the purchaser or transporter of the Products from the Plant, or (z) does not cause the Plant to violate applicable emissions permits or other regulatory requirements.

5.7 Specifications for Residue Gas Redelivered by Processor. The Residue Gas redelivered by Processor shall comply with the Quality Specifications in effect on the date of delivery to the transporter receiving such Residue Gas at the Plant Redelivery Point if that Equity Gas and/or Injected Liquids meets the Quality Specifications upon delivery to the Upstream Pipeline at the Field Delivery Point or Processor has elected to accept Off-Spec Deliveries under the conditions of Sections 5.5 and 5.6 of this Agreement.

5.8 Off Spec Pipeline. Nothing in this Agreement shall require Processor to accept delivery of any Gas that does not conform to the Quality Specifications at the Plant Delivery Point.

6. CONSIDERATION.

6.1 Payment. For each calendar month during the term of this Agreement, Processor agrees, for each Plant, to pay to each of the respective Producers delivering Equity Gas to such Plant, a cash amount equal to the product of:

(1) the Consideration Basis, as defined in Section 6.2, for the respective Plant; and

(2) the PTR for (1) such Producer's Equity Gas Processed at such Plant and (2) any Processor's Retrograde associated with such Producer's Equity Gas.

6.2 Consideration Basis. For purposes of Section 6.1, the term "Consideration Basis" shall mean, and be defined as, for each calendar month during the term of this Agreement, the respective adjusted index price listed by Plant on Exhibit C.

6.3 Consideration Timing. Processor shall pay to Producer the applicable cash consideration set forth in Section 6.1 no later than the last business day of the second month following the month in which the subject PTR and Processor's Retrograde is delivered to a Plant, such payment to be made by wire transfer of immediately available funds to an account designated from time to time by Producers at least fifteen days prior to the date any such payment is due and payable by Processor.

6.4 Consideration Basis Updates. Processor and Producers shall periodically amend Exhibit C, as appropriate, if (i) another Plant is added by Processor, (ii) the price indexes listed in Exhibit C are no longer available or (iii) different index prices would, in the reasonable judgment of Processor and Producers, more accurately represent market conditions. The amount of any new Consideration Basis (as a result of any such amendment to Exhibit C) shall represent the market value of Gas at the appropriate Plant Redelivery Point.

6.5 Processor Provided PTR. Producers and Processor acknowledge and agree that, in lieu of, and as an alternative to, any cash payment required under Section 6.1 to be paid by Processor to Producers, Processor shall have an election to provide, from time to time, PTR at a particular Plant for Processor's own account in respect of all of Producer's Equity Gas Processed at such Plant. Processor agrees that any such election to have Processor so provide PTR for its own account begin on the first day of a month and to provide Producers with at least fifteen days' prior written notice of any such election. If, for any month, Processor has provided to Producers a notice of any such election, Processor shall not be entitled to rescind, revoke or change any such notice for such month. Processor agrees to provide any notifications with respect to such Processor-provided PTR that may be required by an Upstream Pipeline to which Processor delivers such PTR.

7. PTR AND PTR TRANSPORTATION.

Producers shall provide, or cause to be provided, the PTR and the transportation for (i) the PTR associated with the Processing of Equity Gas and (ii) Processor's Retrograde from the wellhead to the Plant Delivery Point, for all Equity Gas and Processor's Retrograde subject to the payment of consideration under Section 6.1. Producers shall also pay for all necessary facilities to cause the Equity Gas and/or Injected Liquids to meet the Quality Specifications and all other costs associated with delivering such PTR and Processor's Retrograde to the Plant Delivery Point. Processor shall pay Producers, for transportation of the PTR and Processor's Retrograde referenced in this Section 7, an amount equal to three cents ($0.03) per MMBTU. If Processor provides PTR for its own account under Section 6.5, Processor shall provide, or cause to be provided, transportation for such PTR at its sole expense.

8. ROYALTY.

8.1 Responsibility for Royalty Payments.

(a) As between Processor and Producers, (i) Producers shall be and remain fully liable for, and shall be fully responsible for remitting any and all payments to the Department of the Interior, the Minerals Management Service, the States of Louisiana, Texas, Mississippi, Alabama and Florida, any other governmental agencies or authorities, and any private lessors who are not federal or state lessors in respect of, any and all federal, state or local royalties and/or severance taxes due on any or all hydrocarbon production of Producers or which in any way relate to, or are in connection with, any of the transactions under this Agreement, including, without limitation, any such federal, state or local royalties and/or severance taxes on, relating to, or calculated on the basis of, any value of (x) the PTR used by Processor, (y) the Products extracted from the Equity Gas and (z) Processor's Retrograde (collectively, "Royalty Charges"), and (ii) Processor shall have no liability for or in respect of any such Royalty Charges.

(b) Producers hereby agree to hold harmless and indemnify Processor (and its Affiliates) from and against, and shall fully and promptly reimburse Processor (and its Affiliates) for, any and all claims, demands, and causes of action of any kind and all losses, damages, costs, and expenses (including court costs and reasonable attorneys' fees) arising from, relating to, or in connection with, any Royalty Charges.

8.2 Delivery of Royalty Taken In Kind. Any request by a private, state or federal governmental lessor to take royalty production in kind for any Raw Make or Products recovered through Processing shall, if lawful, be fulfilled by Processor's delivery to the lessor or its designee of such in kind royalty at a specified location, all as may be required in accord with properly promulgated notices, regulations, or lease terms and to the extent that such delivery by Processor is approved (if required) by private, state or federal lessor. In such case, Processor shall be entitled to recover all costs allowed by statute, regulation or lease term including but not limited to costs of transportation and administrative services. In the event that Processor is prohibited from fulfilling such in kind royalty requests by the private state or federal lessor, then Processor shall be relieved of such obligation but shall tender to Producers an amount of Raw Make or Products recovered from Processing sufficient to fulfill such obligations at a mutually agreeable delivery point.

8.3 Compliance with Federal Acts. As between Processor and Producers, Processor agrees to fulfill Producers' obligation under Section 8(b)(7) of the Outer Continental Shelf Lands Act of 1978 by offering Processor's Retrograde and Products recovered through processing at the market value and point of delivery provided by regulators to small and independent refiners as defined in the Emergency Petroleum Allocations Act of 1973. Processor shall be entitled to retain the proceeds derived from such sale. In the event Processor is prevented for any reason from fulfilling this obligation, Processor shall tender to Producers' sufficient volumes of such Processor's Retrograde and Products sufficient for Producers themselves to fulfill such obligation, and Producers shall reimburse Processor for such liquids at a mutually agreed price which shall include the cost of handling and administration of such sales. Producer shall be entitled to retain the proceeds derived from such sale.

9. METERING, ANALYSIS, AND ALLOCATION.

9.1 Gas Metering, Analysis and Reports.

9.1.1 Producers shall be responsible for the metering at the Field Delivery Points of all Equity Gas and Injected Liquids, the calibration of such meters and any disputes with respect to such metering. Producers agree to use reasonable efforts to cause Gas meters to be tested on a minimum 45-day frequency for correct calibration and agree to provide, or cause to be provided, to Processor reasonable access to all meters.

9.1.2 Producers shall furnish to Processor such statements as Processor may reasonably require to show the volume in MCF of Equity Gas delivered to Upstream Pipelines during a month at each of Producers' Field Delivery Points no later than the tenth business day of the month immediately following the month in which such Gas is delivered to the Upstream Pipeline. This information may be conveyed by facsimile transmission, with subsequent written confirmation, if necessary to meet the aforesaid deadline.

9.1.3 Producers shall furnish to Processor a representative sample of Equity Gas measured at each Field Delivery Point that identifies GPM for each liquefiable hydrocarbon component in accordance with generally accepted industry standards by no later than the tenth business day of the month immediately following the month in which such Gas is delivered to the Upstream Pipeline. This information may be conveyed by facsimile transmission, with subsequent written confirmation, if necessary to meet the aforementioned deadline.

9.2 Liquids Metering and Analysis. Processor shall be responsible for the metering and analysis of all liquefiable hydrocarbons extracted from Equity Gas, calibration of such meters and any disputes with respect to such metering. Processor agrees to cause such liquids meters to be tested on a minimum 45-day frequency for correct calibration and agrees to provide, or cause to be provided to Producers, reasonable access to such meters.

9.3 Meter Failure. In the case of the failure of any measurement meter of a Plant with multiple Gas suppliers, the residue stream attributable to Equity Gas production shall be determined and allotted to Producers according to the provisions of either the applicable agreement controlling the construction and operation of the Plant involved or according to related agreements executed between the owners of the Plant and the owners of any Upstream Pipeline.

10. INDEMNITY.

Processor hereby indemnifies and holds Producers harmless against any and all claims, demands, and causes of action of any kind and all losses, damages, costs, and expenses (including court costs and reasonable attorneys' fees) arising from injuries to persons or property attributable to the Equity Gas or Processor's Retrograde, after delivery thereof has been made to Processor at a Plant Delivery Point. Producers hereby indemnify and hold Processor harmless against any and all claims, demands, and causes of action of any kind and all losses, damages, costs, and expenses (including court costs and reasonable attorneys' fees) arising from injuries to persons or property attributable to the Equity Gas or Injected Liquids, including but not limited to Processor's Retrograde, prior to delivery to Processor at the Plant Delivery Point(s) and after Producer's share of the Residue Gas and Products (if applicable under Section 8.2) is delivered to Producer or Producer's designee at the Plant Redelivery Point(s).

11. CURTAILMENT.

11.1 Mutual Agreement Not to Curtail or Withhold. Producers agree not to unreasonably or arbitrarily withhold production of Equity Gas solely to prejudice the rights granted to Processor hereunder. However, Producers will have no liability to Processor under this Agreement if production is restricted or curtailed for any good faith reason. Likewise, Processor agrees not to arbitrarily withhold Processing services solely to prejudice the rights granted to Producer hereunder. In any such case, Processor shall have no liability to Producer if Processing services are withheld for any good faith reason.

11.2 Limited Right to Interrupt Performance for Maintenance, etc. Processor and any Producer may, without liability, interrupt its performance hereunder for the purpose of making necessary or desirable inspections, maintenance, repairs, alterations and replacements; and the Processor or Producer requiring such relief shall give to the other reasonable notice of its intention to interrupt its performance hereunder, except in cases of emergency where such notice is impracticable or in cases where the operations of the other party will not be affected. The Processor or Producer requiring such relief shall endeavor to arrange such interruptions so as to minimize any adverse economic effect on the other party.

12. FORCE MAJEURE.

12.1 Performance Excused. If either Processor or any Producer is rendered unable, wholly or in part by Force Majeure to perform its obligations under this Agreement, other than the obligation to make payments then due or thereafter becoming due as a result of performance of an obligation prior to such Force Majeure, it is agreed that performance of the respective obligations of Processor and such Producer hereunder, so far as they are affected by such Force Majeure, shall be suspended from the inception of any such inability until it is corrected, but for no longer period. The party claiming such inability shall give notice thereof to the other party as soon as reasonably practicable after the occurrence of the Force Majeure. The party claiming such inability shall promptly correct such inability to the extent it may be corrected through the exercise of reasonable diligence. Neither party shall be liable to the other for any losses or damages, regardless of the nature thereof and howsoever occurring, whether such losses or damages be direct or indirect, immediate or remote, by reason of, caused by, arising out of, or in any way attributable to the suspension or performance of any obligation of either party to the extent that such suspension occurs because a party is rendered unable, wholly or in part, by Force Majeure to perform its obligations.

12.2 Force Majeure Defined. For purposes of this Agreement, the term "Force Majeure" shall mean an event, which (i) is not within the reasonable control of the party claiming suspension, and which by the exercise of reasonable diligence such party is unable to overcome or (ii) acts of God; strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, civil disturbances and riots, and epidemics; landslides, lightning, earthquakes, fires, storms, hurricanes and threats of hurricanes, floods and washouts; arrests, orders, requests, directives, restraints and requirements of the government and governmental agencies, either federal or state, civil or military; explosions, breakage or accident to machinery, equipment or lines of pipe and outages (shutdowns) of equipment, machinery or lines of pipe. The term "Force Majeure" shall also include any event of force majeure occurring with respect to the facilities or services of either party's suppliers or customers delivering or receiving any Raw Make, Products, Slug Liquids, Gas, fuel, or other substance necessary to the performance of such party's obligations, and shall also include curtailment or interruption of deliveries or services by such third party suppliers or customers as a result of an event of force majeure.

13. AUDIT RIGHTS.

For a period of two years following any statement or payment hereunder or such other period of time, if any, as may be prescribed under applicable COPAS standards, Producers or Processor or any third party representative thereof shall have the right, at its expense, upon reasonable notice and at reasonable times, to examine the books and records of the other party hereto, to the extent reasonably necessary to verify the accuracy of any such statement or payment under this Agreement. In addition, Processor and Producer shall be required to retain all records, contracts and files pertaining to royalty payments for the period of time necessary to comply with contractual or regulatory obligations to lessors, and the same shall be made available upon reasonable notice to the other parties hereunder.

14. NOTIFICATIONS.

14.1 Annual Information. On or before September 1 of each year, each Producer shall provide to Processor, without warranty as to accuracy, in reasonable form and substance, Producer's projected volumes and Gas richness (best available composition data) at each existing and projected Field Delivery Point by prospect, Upstream Pipeline and year for the following ten year period. Producers' current "C" volume exploration models or other statistical production models shall be included but may be reported in aggregate. Such provided information shall be referred to collectively as, the "Annual Information". Producers shall also inform Processor as part of the Annual Information of any plans to purchase or sell Dedicated Lease(s).

14.2 Notice of Material Changes to Annual Information. Processor and Producers shall review the Annual Information regularly. Producer shall advise Processor as soon as reasonably practicable of any changes to the Annual Information that could materially impact Processor's plans to Process the projected Equity Gas Volumes.

14.3 Notice of Proposed Transfers of Dedicated Leases. In addition to notifying Processor as a part of the Annual Information, Producers shall notify Processor, as soon as reasonably practicable, of, but in any case prior to, any efforts to sell, exchange, or otherwise assign any Dedicated Lease, and Processor shall inform the Producer of its intent to reserve or release such Dedicated Lease from this Agreement.

14.4 Notice of Pending Transportation Agreements. Each Producer shall notify Processor as soon as reasonably practicable of any ongoing or planned negotiation for the transportation of Equity Gas in an Upstream Pipeline, in order to facilitate Processor's entering into a Gas Processing Agreement for such Equity Gas. Processor and Producer agree to enter into such transportation and Gas Processing contracts contemporaneously, to the extent reasonably practicable and provided that a Producer shall not be obligated to delay entry into any transportation contract when such Producer reasonably believes such delay will result in curtailment of Equity Gas.

14.5 Notice of Scheduled Plant Downtime. Processor agrees to notify Producers as soon as reasonably practicable of any scheduled Plant downtime that could impact Producer's ability to continue to produce Equity Gas.

15. CONFIDENTIALITY.

15.1 General. Producers or Processor shall not disclose the terms of this Agreement (or the results of any audit pursuant to Section 13) to a third party (other than the employees, lenders, counsel, consultants, or accountants of a Processor or a Producer who have agreed to keep such terms confidential) except (i) in order to comply with any applicable law, order, regulation or exchange rule, (ii) in connection with bona fide negotiations with a potential third party transferee of a Dedicated Lease or (iii) in connection with bona fide negotiations involving the acquisition or construction of Plant capacity or negotiations on contracts for third party Gas Processing agreements. Each party shall notify the other party of any proceeding of which it is aware which may result in disclosure and use reasonable efforts to prevent or limit the disclosure. Such confidentiality obligations shall terminate two years after the Termination Date.

15.2 Annual Information. Processor hereby agrees to maintain Annual Information as confidential and agrees to disclose Annual Information only (i) to employees, lenders, counsel, consultants, or accountants of Processor or an Affiliate of Processor, who need to know and agree to maintain the confidentiality of such Annual Information, and (ii) to the extent necessary to comply with any applicable law, order, regulation or exchange rule. Processor shall notify the applicable Producers of any proceeding of which it is aware which may result in disclosure and use reasonable efforts to prevent or limit the disclosure. Such confidentiality obligations shall terminate two years after the Termination Date.

16. DISPUTE RESOLUTION.

16.1 Arbitration. Producers and Processor hereby agree that any claim, controversy or dispute arising among the parties or their successors in interest or between any of them relating to this Agreement, or any of their respective rights, duties or obligations under or in connection with this Agreement (a "Dispute"), if not resolved by the parties in the ordinary course of business or under the procedures set forth in Sections 16.2 and 16.3, shall with reasonable promptness be submitted to and determined by binding arbitration in Houston, Texas in accordance with the commercial arbitration rules of the American Arbitration Association ("AAA") then in effect; and judgment upon any arbitration award rendered pursuant to and in accordance with the arbitration provisions of Section 16.4 may be entered in any court having jurisdiction over such arbitration proceeding and over Producers and Processor; and any such party may institute proceedings in any court having jurisdiction for the specific performance by any party of any such arbitration award. Each of the parties specifically agrees to be bound by any arbitration award or determination made in any such arbitration proceeding. This Section 16 will be the sole and exclusive procedure for the resolution of any Dispute, except that any party, without prejudice to the following procedures, may file a complaint to seek preliminary injunctive or other provisional judicial relief in a court of competent jurisdiction, if in its sole judgment, that action is necessary to avoid irreparable damage or to preserve the status quo; provided, however, that any such provisional relief granted shall be vacated or extended upon and in accordance with any determination of the arbitrators with respect thereto.

16.2 Initiation of Procedures. Any party wishing to initiate the dispute resolution procedures set forth in this Section 16 with respect to a Dispute not resolved in the ordinary course of business must give written notice of the Dispute to the other parties ("Dispute Notice"). The Dispute Notice must include (1) a statement of that party's position and a summary of arguments supporting that position, and (2) the name and title of (a) the executive responsible for administering this Agreement or the matter in Dispute and who will represent that party and (b) any other person who will accompany the executive in the negotiations under Section 16.3. Within 15 days after delivery of the Dispute Notice, the receiving parties will submit to the other a written response. The response will include (1) a statement of that party's position and a summary of arguments supporting that position, and (2) the name and title of (x) the executive who will represent that party and (y) any other person who will accompany the executive in the negotiations conducted under Section 16.3.

16.3 Negotiation Between Executives. If any party has given a Dispute Notice under Section 16.2, the parties will attempt in good faith to resolve the Dispute within 30 days after the receipt of the written response to the Dispute Notice by negotiations between executives identified in Section 16.2. During the 30 days following the receipt of the written response to the Dispute Notice, the executives (identified in Section 16.2) will meet no less than eight hours a day and exhaustively negotiate in good faith and at the expense of all other responsibilities.

16.4 Binding Arbitration. At the end of the 30-day period provided in Section 16.3, if the executives have been unable to resolve the Dispute, and if a disputing party wishes to submit the Dispute to binding arbitration, the disputing party shall provide to the other disputing party three business days' prior written notice of such disputing party's intention to submit the Dispute to binding arbitration. The other disputing party shall be entitled to join in the submission of the Dispute to binding arbitration in accordance with the commercial arbitration rules of the AAA (expedited procedures). The AAA shall be instructed to choose an arbitrator who shall have a minimum of 15 years experience in the oil and gas processing industry, or such other experience such that he or she is considered an expert on the business of the Processor. Notice of a disputing party's submission of the matter for arbitration shall be given to the other party or parties within three business days thereafter (the "Arbitration Notice"). Upon delivery of the Arbitration Notice by the disputing party, each disputing party shall have 30 days to provide the arbitrator (and the disputing party) with a statement of its position (with supporting documentation) regarding the matter or matters in dispute together with its best and final offer for settlement of the Dispute. The failure to provide a statement of position within this period shall constitute a waiver of a disputing party's right to have such materials considered by the arbitrator. The arbitrator shall consider the statements of position submitted by the disputing parties and shall, within 30 business days after receipt of such materials, issue his or her decision in writing picking one of the statements of position submitted by the disputing parties as the position to be adopted to settle the Dispute. All determinations made by the arbitrator shall be final, conclusive and binding on the disputing parties. Each of the disputing parties will pay one-half of the fees of the arbitrator and all other arbitration fees and expenses and the fees of their respective arbitrators (if required).

17. TRANSFER AND ASSIGNMENT.

17.1 Successors and Assigns. This Agreement shall be binding upon Producers and Processor. Except for an assignment by Processor in connection with the sale of all or a substantial part of Processor's assets, this Agreement shall not be assignable by Processor except with the prior written consent of the affected Producer, or by a Producer, except with the prior written consent of Processor; provided, however, that no such consent may be unreasonably withheld or delayed.

17.2 Processor's Rights Under Leases. Subject to Section 17.4, Producers hereby agree that it is their intent that, to the extent permitted by law, this Agreement constitutes a conveyance by Producers of a portion of their rights as lessee under the Dedicated Leases and that this Agreement shall bind all persons that now or at any time hereafter have any right as lessee or otherwise under any Dedicated Leases, whether by voluntary transfer, involuntary transfer, or otherwise of Leases; provided, however, that nothing in this Section 17.2 or any other provision of this Agreement shall require, or be deemed to require, Processor to pay, or be responsible for, any Royalty Charges, it being the intent of the parties to this Agreement that Producers shall pay, and be responsible for, any and all Royalty Charges, as provided in Section 8.1. Producers further agree (i) to make any transfer of any Dedicated Lease subject to the terms and conditions of this Agreement and (ii) not to transfer Producer's interest in a Dedicated Lease without first requiring the transferee to execute and deliver to Producer and Processor a Letter of Attornment in the form attached hereto as Exhibit E.

17.3 Affiliates of Producer Parties. Subject to Section 17.4, it is the intention of the parties that this Agreement shall bind not only the Producers who are made a party to this Agreement but also their respective Affiliates, successors and assigns. Each Producer covenants and agrees to exercise its best efforts to have each of its Affiliates, successors and assigns that acquires an interest in a Lease become and be made a party to this Agreement and to perform its obligations hereunder.

17.4 Excepted Leases. As to any Dedicated Leases, or portions thereof, that were transferred or assigned by Producers to third parties during the period of January 1, 1998 through May 30, 1999, inclusive, that were not made subject to the Third Amendment as a condition of any such transfer or assignment ("Excepted Leases"), Processor waives the application of the Third Amendment as to the Excepted Leases, and the Parties agree that this Agreement shall not apply to the Excepted Leases.

18. MISCELLANEOUS.

18.1 Title and Captions. All section titles or captions in this Agreement are for convenience of reference only. They are not intended to be part of this Agreement or to in any way define, limit, extend, or describe the scope or intent of any provisions of this Agreement. Except as specifically provided otherwise, reference to "Sections" and "Exhibits" are to Articles and Sections of and Exhibits to this Agreement.

18.2 Pronouns and Plurals. Whenever the context so requires, any pronoun used in this Agreement includes the corresponding masculine, feminine or neuter forms, and the singular form of nouns, pronouns and verbs includes the plural and vice versa.

18.3 Separability. Each provision of this Agreement shall be considered to be separable and, if, for any reason, any such provision, is determined to be in whole or part invalid and contrary to any existing or future applicable law, such invalidity shall not impair the operation of or affect those portions of this Agreement that are valid, and this Agreement shall be construed and enforced in all respects as if the invalid or unenforceable provision had been omitted.

18.4 Successors. This Agreement shall be binding upon and inure to the benefit of the parties and their respective successors and assigns but this provision shall not be deemed to permit any assignment by a party of any of its rights or obligations under this Agreement except as expressly provided herein.

18.5 Further Actions. Each party agrees to execute and deliver such further instruments and do such further acts and things as may be required or useful to carry out or further evidence the intent and purpose of this Agreement and which are not inconsistent with its terms.

18.6 Notices. All notices or other communications hereunder must be in writing and must be delivered either personally or by (i) facsimile means (delivered during the recipient's regular business hours), (ii) registered or certified mail (postage prepaid and return receipt requested), or (iii) express courier or delivery service, addressed as follows:

Producers:	[Producer] c/o Shell Offshore, Inc. 200 N. Dairy Ashford Houston, TX 77079 Fax #: (281) 544-3544 Attn: Manager Marketing and Transportation	Processor:	Enterprise Gas Processing, LLC 2727 North Loop West - 7th Floor Houston, TX 77008 Fax #: (713) 880-6960 Attn: Paul Johnson

or at such other address and number as any party shall have previously designated by notice given to the other parties in the manner provided in this Section. Notices shall be deemed given when received during normal business hours if sent by facsimile means (confirmation of such receipt by confirmed facsimile transmission being deemed receipt of communications sent by facsimile means), and when delivered and receipted for (or upon the date of attempted delivery where delivery is refused), if hand-delivered, sent by express courier or delivery service, or sent by certified or registered mail.

18.7 Amendment only in Writing. No amendment, waiver, modification or change of this Agreement shall be enforceable unless in writing signed by the Party against whom enforcement is sought.

18.8 Right of Ingress and Egress. To the extent Producers are able to grant such rights, Processor shall have the right of ingress and egress to and from the premises of Producers and to and from the

Field Delivery Points for all purposes necessary for the fulfillment of this Agreement.

18.9 No Special Damages. No party shall be liable for any consequential, incidental, punitive, exemplary, or indirect damages in tort, contract, under any indemnity provision or otherwise.

18.10 Applicable Law. This Agreement shall be governed by, and construed, interpreted and enforced in accordance with, the substantive law of the state of Louisiana without regard to principles of conflicts of laws.

18.11 Entire Agreement. This Agreement embodies the entire agreement and understanding between Producers and Processor and supersedes all prior agreements and understandings relating to the subject matter hereof, except that Section 2 of the Third Amendment is hereby incorporated in this Agreement by reference and shall survive this Agreement as though fully set forth herein.

18.12 Counterparts. This Agreement may be executed in one or more counterparts and each of such counterparts, for all purposes, shall be deemed to be an original, but all of such counterparts together shall constitute but one and the same instrument, binding upon all parties, notwithstanding that all of the parties may not have executed the same counterpart.

IN WITNESS WHEREOF, the Parties hereto, by their duly authorized representatives have executed this Agreement effective as of the Effective Date.

<u>PRODUCERS</u>:
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SHELL OIL COMPANY WITNESSES:

By: /s/ B.K. Garrison ______________________________
Name: B.K. Garrison
Title: Attorney-in-Fact ______________________________

SHELL OFFSHORE INC. WITNESSES:

By: /s/ J.W. Kimmel ______________________________
Name: J.W. Kimmel
Title: Attorney-in-Fact ______________________________

SHELL CONSOLIDATED ENERGY RESOURCES INC. WITNESSES:

By: /s/ Jeri Eagan ______________________________
Name: Jeri Eagan
Title: Vice President ______________________________

SHELL LAND and ENERGY COMPANY WITNESSES:

By: /s/ Jeri Eagan ______________________________
Name: Jeri Eagan
Title: Executive Vice President and Chief Financial Officer ______________________________

SHELL FRONTIER OIL and GAS INC. WITNESSES:

By: /s/ Jeri Eagan ______________________________
Name: Jeri Eagan
Title: Executive Vice President and Chief Financial Officer ______________________________

SHELL EXPLORATION and PRODUCTION COMPANY WITNESSES:

By: /s/ Jerri Eagan ______________________________
Name: Jeri Eagan
Title: Executive Vice President Finance and Chief Financial Officer ______________________________

<u>PROCESSOR</u>:

ENTERPRISE GAS PROCESSING, LLC WITNESSES:

By: /s/ W. Ordemann ______________________________
Name: W. Ordemann
Title: Vice President ______________________________