FORM 10-Q

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

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

For the quarterly period ended September 30, 1999

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 45,552,915 Common Units outstanding as of November 15, 1999.

Enterprise Products Partners L.P. and Subsidiaries

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PART 1. FINANCIAL INFORMATION.
Item 1. CONSOLIDATED FINANCIAL STATEMENTS.

Enterprise Products Partners L.P.
Consolidated Balance Sheets
(Amounts in thousands)

ASSETS	December 31, 1998	September 30, 1999 (Unaudited)
Current Assets		
Cash and cash equivalents	$ 24,103	$ 21,647
Accounts receivable - trade	57,288	187,615
Accounts receivable - affiliates	15,546	50,562
Inventories	17,574	102,992
Current maturities of participation in notes receivable from unconsolidated affiliates	14,737	9,778
Prepaid and other current assets	8,445	11,283
Total current assets	137,693	383,877
Property, Plant and Equipment, Net	499,793	772,157
Investments in and Advances to Unconsolidated Affiliates	91,121	235,864
Participation in Notes Receivable from Unconsolidated Affiliates	11,760	
Intangible assets, net of amortization of $702		79,187
Other Assets	670	1,515
Total	$ 741,037	$ 1,472,600
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of long-term debt		$ 175,000
Accounts payable - trade	$ 36,586	139,851
Accrued gas payables	27,183	143,397
Accrued expenses	7,540	13,071
Other current liabilities	11,462	15,017
Total current liabilities	82,771	486,336
Long-Term Debt	90,000	215,000
Other Long-Term Liabilities		539
Minority Interest	5,730	7,801
Commitments and Contingencies		
Partners' Equity		
Common Units (45,552,915 Units outstanding at December 31, 1998 and September 30, 1999)	433,082	417,651
Subordinated Units (21,409,870 Units outstanding at December 31, 1998 and September 30, 1999)	123,829	126,496
Special Units (14,500,000 Units outstanding at September 30, 1999)		215,828
Units acquired by Trust, at cost (267,200 Units outstanding at September 30, 1999)		(4,727)
General Partner	5,625	7,676
Total Partners' Equity	562,536	762,924
Total	$ 741,037	$ 1,472,600

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 September 30, 1998	Three Months Ended September 30, 1999	Nine Months Ended September 30, 1998	Nine Months Ended September 30, 1999
REVENUES				
Revenues from consolidated operations	$ 164,620	$ 441,880	$ 562,703	$ 763,793
Equity income in unconsolidated affiliates	4,171	3,148	10,824	7,591
Total	168,791	445,028	573,527	771,384
COST AND EXPENSES				
Operating costs and expenses	153,197	401,155	521,428	688,250
Selling, general and administrative	3,751	3,200	15,362	9,200
Total	156,948	404,355	536,790	697,450
OPERATING INCOME	11,843	40,673	36,737	73,934
OTHER INCOME (EXPENSE)				
Interest expense	(2,500)	(4,036)	(13,304)	(7,995)
Interest income from unconsolidated affiliates	340	407	340	1,096
Interest income - other	85	682	645	1,114
Other, net	34	(1,010)	464	(1,522)
Other income (expense)	(2,041)	(3,957)	(11,855)	(7,307)
INCOME BEFORE EXTRAORDINARY ITEM AND MINORITY INTEREST	9,802	36,716	24,882	66,627
Extraordinary charge on early extinguishment of debt	(27,176)		(27,176)	
INCOME (LOSS) BEFORE MINORITY INTEREST	(17,374)	36,716	(2,294)	66,627
MINORITY INTEREST	174	(370)	23	(672)
NET INCOME (LOSS)	$ (17,200)	$ 36,346	$ (2,271)	$ 65,955
ALLOCATION OF NET INCOME (LOSS) TO:				
Limited partners	$ (17,028)	$ 35,983	$ (2,248)	$ 65,295
General partner	$ (172)	$ 363	$ (23)	$ 660
Number of Units Used in Computing Basic Earnings per Common Unit	63,441	66,696	57,830	66,715
BASIC EARNINGS PER COMMON UNIT				
Income before extraordinary item and minority interest per common unit	$ 0.15	$ 0.54	$ 0.43	$ 0.99
Net income (loss) per common unit	$ (0.27)	$ 0.54	$ (0.04)	$ 0.98
Number of Units Used in Computing Diluted Earnings per Common Unit	63,441	76,310	57,830	69,955
DILUTED EARNINGS PER COMMON UNIT				
Income before extraordinary item and minority interest per common unit	$ 0.15	$ 0.48	$ 0.43	$ 0.94
Net income (loss) per common unit	$ (0.27)	$ 0.47	$ (0.04)	$ 0.93

See Notes to Unaudited Consolidated Financial Statements

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

	Nine Months Ended September 30, 1998	1999
OPERATING ACTIVITIES		
Net income (loss)	($2,271)	$65,955
Adjustments to reconcile net income (loss) to cash flows provided by (used for) operating activities:		
Extraordinary item - early extinguishment of debt	27,176	
Depreciation and amortization	14,796	17,280
Equity in income of unconsolidated affiliates	(10,824)	(7,591)
Leases paid by EPCO	3,327	7,918
Minority interest	(23)	672
(Gain) loss on sale of assets	(274)	122
Net effect of changes in operating accounts	(75,824)	(34,246)
Operating activities cash flows	(43,917)	50,110
INVESTING ACTIVITIES		
Capital expenditures	(7,159)	(10,603)
Proceeds from sale of assets	1,890	8
Acquisitions		(208,095)
Participation in notes receivable from unconsolidated affiliates:		
Purchase of notes receivable	(33,724)	
Collection of notes receivable	3,542	16,719
Unconsolidated affiliates:		
Investments in and advances to	(19,988)	(58,460)
Distributions received	6,601	4,607
Investing activities cash flows	(48,838)	(255,824)
FINANCING ACTIVITIES		
Net proceeds from sale of common units	243,309	
Long-term debt borrowings	75,000	350,000
Long-term debt repayments	(256,493)	(59,923)
Net decrease in restricted cash	4,522	
Cash dividends paid to partners		(81,321)
Cash dividends paid to minority interest		(830)
Units acquired by consolidated trusts		(4,727)
Cash contributions from EPCO to minority interest		59
Financing activities cash flows	66,338	203,258
CASH CONTRIBUTIONS FROM EPCO	18,468	
NET CHANGE IN CASH AND CASH EQUIVALENTS	(7,949)	(2,456)
CASH AND CASH EQUIVALENTS, JANUARY 1	18,941	24,103
CASH AND CASH EQUIVALENTS, SEPTEMBER 30	$ 10,992	$ 21,647

See Notes to Unaudited Consolidated Financial Statements

1. GENERAL

In the opinion of Enterprise Products Partners L.P. (the "Company"), the accompanying unaudited consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for a fair presentation of the Company's consolidated financial position as of September 30, 1999, consolidated results of operations for the three and nine month periods ended September 30, 1999 and 1998, and its consolidated cash flows for the nine month periods ended September 30, 1999 and 1998. 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 for the year ended December 31, 1998 ("Form 10-K").

The results of operations for the three and nine month periods ended September 30, 1999 are not necessarily indicative of the results to be expected for the full year.

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

At September 30, 1999, the Company's significant unconsolidated affiliates accounted for by the equity method included the following:

Belvieu Environmental Fuels ("BEF") - a 33-1/3% economic interest in a Methyl Tertiary Butyl Ether ("MTBE") production facility located in southeast Texas.

Baton Rouge Fractionators LLC ("BRF") - a 31.25% economic interest in a natural gas liquid ("NGL") fractionation facility located in southeastern Louisiana.

Baton Rouge Propylene Concentrator, LLC ("BRPC") - a 30.0% economic interest in a propylene concentration unit located in southeastern Louisiana which is under construction and scheduled to become operational in the third quarter of 2000.

EPIK Terminalling L.P. and EPIK Gas Liquids, LLC (collectively, "EPIK") - a 50% aggregate economic interest in a refrigerated NGL marine terminal loading facility located in southeast Texas.

Wilprise Pipeline Company, LLC ("Wilprise") - a 33-1/3% economic interest in a NGL pipeline system located in southeastern Louisiana.

Tri-States NGL Pipeline LLC ("Tri-States") - an aggregate 33-1/3% economic interest in a NGL pipeline system located in Louisiana, Mississippi, and Alabama. In connection with the Tejas Natural Gas Liquids, LLC ("TNGL") acquisition (discussed in Note 3) the Company acquired an additional 16-2/3% interest bringing the total investment in Tri-States to the current 33-1/3%.

Belle Rose NGL Pipeline LLC ("Belle Rose") - a 41.7% economic interest in a NGL pipeline system located in south Louisiana. The Company's interest in Belle Rose was acquired in connection with the TNGL acquisition which is discussed in Note 3.

K/D/S Promix LLC ("Promix") - a 33-1/3% economic interest in a NGL fractionation facility and related storage facilities located in south Louisiana. The Company's interest in Promix was acquired in connection with the TNGL acquisition which is discussed in Note 3.

The Company's investments in and advances to unconsolidated affiliates also includes Venice Energy Services Company, LLC ("VESCO") and Dixie Pipeline Company ("Dixie"). The VESCO investment consists of a 13.1% economic interest in a LLC owning a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines in Louisiana. The Dixie investment consists of an 11.5% interest in a corporation owning a 1,300-mile propane pipeline and the associated facilities extending from Mont Belvieu, Texas to North Carolina. These investments are accounted for using the cost method in accordance with generally accepted accounting principles.

Effective July 1, 1999, a subsidiary of Enterprise Products Operating L.P. (the "Operating Partnership") acquired the remaining 51% economic interest of Mont Belvieu Associates ("MBA") from Kinder Morgan Energy Partners L.P. ("Kinder Morgan") and Enterprise Products Company ("EPCO") (see Note 3 for a general discussion regarding this acquisition). As a consequence, the results of operations since July 1, 1999 are included in consolidated operations. The 49% economic interest in income of MBA held by the Company prior to the acquisition was recorded as equity income.

In conjunction with the acquisition of TNGL from Tejas Energy, LLC ("Tejas Energy") effective August 1, 1999, the Company currently owns 100% of the economic interest in Entell NGL Services, LLC ("Entell") (see Note 3 for a general discussion regarding the TNGL acquisition). As a result, Entell is now a wholly-owned subsidiary of the Operating Partnership. The Operating Partnership's 50% economic interest in the income of Entell prior to the acquisition has been recorded as equity income.

Investments in and advances to unconsolidated affiliates at:

	December 31, 1998	September 30, 1999
BEF	$ 50,079	$ 56,493
MBA	12,551	
BRF	17,896	34,656
BRPC		8,400
EPIK	5,667	12,974
Wilprise	4,873	8,063
Tri-States	55	28,324
Promix		29,590
Dixie		20,000
VESCO		25,000
Belle Rose		12,364
Total	$ 91,121	$ 235,864

Equity in income of unconsolidated affiliates for the:

	Three Months ended September 30, 1998	Three Months ended September 30, 1999	Nine Months ended September 30, 1998	Nine Months ended September 30, 1999
BEF	$ 3,355	$ 2,519	$ 6,609	$ 4,756
MBA	862	72	4,305	1,256
BRF		(258)		(544)
BRPC		4		4
EPIK	(46)	59	(90)	236
Entell		258		1,389
Wilprise		(130)		(130)
Tri-States		472		472
Belle Rose		245		245
Promix		(93)		(93)
Total	$ 4,171	$ 3,148	$ 10,824	$ 7,591

3. ACQUISITIONS

Acquisition of Tejas Natural Gas Liquids, LLC

Effective August 1, 1999, the Company acquired TNGL from a subsidiary of Tejas Energy, an affiliate of Shell Oil Company ("Shell"). TNGL engages in natural gas processing and NGL fractionation, transportation, storage and marketing in Louisiana and Mississippi. TNGL's assets include a 20-year natural gas processing agreement with Shell for the rights to process its current and future natural gas production from the state and federal waters of the Gulf of Mexico and varying interests in eleven natural gas processing plants (including one under construction) with a combined gross capacity of 11.0 billion cubic feet per day (Bcfd) and a net capacity of 3.1 Bcfd; four NGL fractionation facilities with a combined gross capacity of 281,000 barrels per day (BPD) and net capacity of 131,500 BPD; four NGL storage facilities with approximately 29.5 million barrels of gross capacity and 8.8 million barrels of net capacity; and over 2,100 miles of NGL pipelines (including an 11.5% interest in Dixie Pipeline).

As discussed in Note 5, the TNGL acquisition was purchased with a combination of $166 million in cash and 14.5 million issuance of non-distribution bearing convertible Special Units. The $166 million cash portion of the purchase price was funded with borrowings under the Company's new $350 million bank credit facility led by The Chase Manhattan Bank. The Special Units were valued within a range provided by an independent investment banker using both present value and Black Scholes Model methodologies. The consideration for the acquisition was determined by arms-length negotiation among the parties.

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

Current Assets	$127.5
Investments	97.7
Property, net	225.8
Intangible asset	71.1
Liabilities	(145.7)
Total purchase price	$ 376.3

The $71.1 million intangible asset is associated with the 20-year natural gas processing agreement with Shell ("Shell Contract") and is being amortized over a period of 20 years, approximating the life of the agreement. For the quarter ending September 30, 1999, approximately $0.6 million of such amortization was charged to expense. The assets, liabilities and results of operations of TNGL are included with those of the Company as of August 1, 1999. Historical information for periods prior to August 1, 1999 do not reflect any impact associated with the TNGL acquisition.

As described in Note 5, Tejas Energy has the opportunity to earn an additional 6.0 million non-distribution bearing, convertible special Contingency Units over the next two years upon the achievement of certain gas production thresholds under the Shell Contract. If such special Contingency Units are issued, the purchase price will be adjusted accordingly.

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

Effective July 1, 1999, the Company acquired Kinder Morgan Energy Partners L.P.'s ("Kinder Morgan") 25% indirect ownership interest and EPCO's 0.5% indirect ownership interest in a 210,000 BPD NGL fractionation facility located in Mont Belvieu, Texas for approximately $41 million in cash and the assumption of approximately $ 4 million of debt. The $41 million in cash was funded with borrowings under the Company's new $350 million bank credit facility led by The Chase Manhattan Bank.

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

Property, net	$36.3
Intangible asset	8.7
Liabilities	(3.8)
Total purchase price	$ 41.2

The intangible asset represents the excess cost of purchase price over the fair market value of the assets acquired and is being amortized over 20 years. For the quarter ending September 30, 1999, approximately $0.1 million of such amortization was charged to expense.

Prior to this transaction, the Company held a 25% indirect and a 12.5% direct ownership interest in the fractionation facility. The indirect ownership interests of the Company, Kinder Morgan and EPCO were held through MBA. Prior to the acquisition, the 12.5% direct ownership interest and the 49% equity ownership of MBA were held by Enterprise Products Texas Operating L.P. ("EPTexas"). Upon completion of the transaction, EPTexas held 100% of MBA and, as a result, MBA was merged into EPTexas. The net assets and results of operations of MBA are included with those of EPTexas beginning with the July 1, 1999 acquisition date. Historical information for periods prior to July 1, 1999 does not reflect any impact associated with the acquisition of the Mont Belvieu Fractionation Facility. The Company's equity in the earnings of MBA prior to July 1, 1999 is included in equity in income of unconsolidated affiliates.

Pro Forma Financial Information

The balances included in the consolidated balance sheets related to the current year acquisitions are based upon preliminary information and are subject to change as additional information is obtained. Material changes in the preliminary allocations are not anticipated by management.

The following pro forma information gives effect to the acquisition of TNGL and MBA as if the business combination had occurred at the beginning of each period presented. The pro forma adjustments which have been made are based on the preliminary allocation of the purchase price to assets acquired and liabilities assumed. This pro forma information should be read in conjunction with the accompanying interim Consolidated Financial Statements, Management's Discussion and Analysis of Financial Condition and Results of Operations. This pro forma information is not necessarily indicative of the financial results which would have occurred had the acquisition taken place on the dates indicated, nor is it necessarily indicative of future financial results.

(Amounts in millions)	Three Months Ended September 30, 1998	Three Months Ended September 30, 1999	Nine Months Ended September 30, 1998	Nine Months Ended September 30, 1999
Unaudited Pro Forma Financial Information				
Revenues	$ 282.6	$ 505.7	$ 1,043.9	$ 1,153.7
Income before extraordinary items	0.6	40.8	29.0	78.0
Net Income	(26.6)	40.8	1.9	78.0
Earnings per Unit:				
Basic	$ (0.40)	$ 0.61	$ 0.03	$ 1.17
Diluted	$ (0.33)	$ 0.50	$ 0.02	$ 0.96

4. LONG-TERM DEBT

Existing Bank Credit facility. In July 1998, the Operating Partnership entered into a $200.0 million bank credit facility ("Bank Revolver A") that includes a $50.0 million working capital facility and a $150.0 million revolving term loan facility. The $150.0 million revolving term loan facility includes a sublimit of $30.0 million for letters of credit. As of September 30, 1999, the Company has borrowed $175.0 million under the bank credit facility which is due in July 2000. Management is currently exploring options to convert this short-term debt into long-term debt.

The Company's obligations under the bank credit facility are unsecured general obligations and are non-recourse to the General Partner. Borrowings under the bank credit facility will bear interest at either the bank's prime rate or the Eurodollar rate plus the applicable margin as defined in the facility. The bank credit facility will expire in July 2000 and all amounts borrowed thereunder shall be due and payable at that time. There must be no amount outstanding under the working capital facility for at least 15 consecutive days during each fiscal year.

As amended on July 28, 1999, the existing credit agreement relating to the facility contains a prohibition on distributions on, or purchases or redemptions of, Units if any event of default is continuing. In addition, the bank credit facility contains various affirmative and negative covenants applicable to the ability of the Company to, among other things, (i) incur certain additional indebtedness, (ii) grant certain liens, (iii) sell assets in excess of certain limitations, (iv) make investments, (v) engage in transactions with affiliates and (vi) enter into a merger, consolidation or sale of assets. The bank credit facility requires that the Operating Partnership satisfy the following financial covenants at the end of each fiscal quarter: (i) maintain Consolidated Tangible Net Worth (as defined in the bank credit facility) of at least $250.0 million, (ii) maintain a ratio of EBITDA (as defined in the bank credit facility) to Consolidated Interest Expense (as defined in the bank credit facility) for the previous 12-month period of at least 3.5 to 1.0 and (iii) maintain a ratio of Total Indebtedness (as defined in the bank credit facility) to EBITDA of no more than 3.0 to 1.0.

A "Change of Control" constitutes an Event of Default under the bank credit facility. A Change of Control includes any of the following events: (i) Dan L. Duncan (and/or certain affiliates) cease to own (a) at least 51% (on a fully converted, fully diluted basis) of the economic interest in the capital stock of EPCO or (b) an aggregate number of shares of capital stock of EPCO sufficient to elect a majority of the board of directors of EPCO; (ii) EPCO ceases to own, through a wholly owned subsidiary, at least 65% of the outstanding membership interest in the General Partner and at least a majority of the outstanding Common Units; (iii) any person or group beneficially owns more than 20% of the outstanding Common Units (excluding certain affiliates of EPCO or Shell Oil Company); (iv) the General Partner ceases to be the general partner of the Company or the Operating Partnership; or (v) the Company ceases to be the sole limited partner of the Operating Partnership.

New Bank Credit facility. On July 28, 1999, the Operating Partnership entered into a $350.0 million bank credit facility ("Bank Revolver B") that includes a

$50.0 million working capital facility and a $300.0 million revolving term loan facility. The $300.0 million revolving term loan facility includes a sublimit of $10.0 million for letters of credit. The proceeds of this loan were used to finance the acquisition of TNGL and the MBA ownership interests. Future uses of the remaining credit line include the purchase of the Lou-Tex pipeline (see Note 10).

Borrowings under the bank credit facility will bear interest at either the bank's prime rate or the Eurodollar rate plus the applicable margin as defined in the facility. The bank credit facility will expire in July 2001 and all amounts borrowed thereunder shall be due and payable at that time. There must be no amount outstanding under the working capital facility for at least 15 consecutive days during each fiscal year.

The credit agreement relating to the new facility contains a prohibition on distributions on, or purchases or redemptions of Units if any event of default is continuing. In addition, the bank credit facility contains various affirmative and negative covenants applicable to the ability of the Company to, among other things, (i) incur certain additional indebtedness, (ii) grant certain liens, (iii) sell assets in excess of certain limitations, (iv) make investments, (v) engage in transactions with affiliates and (vi) enter into a merger, consolidation, or sale of assets. The bank credit facility requires that the Operating Partnership satisfy the following financial covenants at the end of each fiscal quarter: (i) maintain Consolidated Tangible Net Worth (as defined in the bank credit facility) of at least $250.0 million, (ii) maintain a ratio of EBITDA (as defined in the bank credit facility) to Consolidated Interest Expense (as defined in the bank credit facility) for the previous 12-month period of at least 3.5 to 1.0 and (iii) maintain a ratio of Total Indebtedness (as defined in the bank credit facility) to EBITDA of no more than 3.0 to 1.0.

A "Change of Control" constitutes an Event of Default under the bank credit facility. A Change of Control includes any of the following events: (i) Dan L. Duncan (and/or certain affiliates) cease to own (a) at least 51% (on a fully converted, fully diluted basis) of the economic interest in the capital stock of EPCO or (b) an aggregate number of shares of capital stock of EPCO sufficient to elect a majority of the board of directors of EPCO; (ii) EPCO ceases to own, through a wholly owned subsidiary, at least 65% of the outstanding membership interest in the General Partner and at least a majority of the outstanding Common Units; (iii) any person or group beneficially owns more than 20% of the outstanding Common Units (excluding certain affiliates of EPCO and Shell Oil Company); (iv) the General Partner ceases to be the general partner of the Company or the Operating Partnership; or (v) the Company ceases to be the sole limited partner of the Operating Partnership.

Long-term debt consisted of the following:

	December 31, 1998	September 30, 1999 (Unaudited)
Bank Revolver A	$90,000	$175,000
Bank Revolver B		215,000
Total	90,000	390,000
Less current maturities of long-term debt		(175,000)
Long-term debt	$90,000	$215,000

5. CAPITAL STRUCTURE

At September 30, 1999, the Company had 33,552,915 Common Units and 21,409,870 Subordinated Units outstanding held by EPCO (the Company's ultimate parent), 12,000,000 Common Units outstanding held by third parties, and 14,500,000 non-distribution bearing, convertible Special Units held by Tejas Energy. During the first quarter of 1999, the Company established a revocable grantor trust (the "Trust") to fund future liabilities of a long-term incentive plan. At September 30, 1999, the Trust had purchased a total of 267,200 Common Units (the "Trust Units") which are accounted for in a manner similar to treasury stock under the cost method of accounting. The Trust Units are considered outstanding and will receive distributions; however, they are excluded from the calculation of net income per Unit in accordance with generally accepted accounting principles.

On August 1, 1999, in exchange for its NGL business (see Note 3), Tejas Energy received 14.5 million non-distribution bearing, convertible Special Units in the Company and $166 million in cash. The 14.5 million non-distribution bearing, convertible Special Units received by Tejas Energy represent an approximate 17.6% equity ownership in the Company. These convertible Special Units do not accrue distributions and are not entitled to cash distributions until their conversion into Common Units, which occurs automatically with respect to 1.0 million Units on August 1, 2000 (or the day following the record date for determining units entitled to receive distributions in the second quarter of 2000), 5.0 million Units on August 1, 2001 and 8.5 million Units on August 1, 2002.

Tejas Energy has the opportunity to earn an additional 6 million non-distribution bearing, convertible Contingency Units over the next two years based on certain performance criteria. Shell will earn 3 million convertible Contingency Units if at any point during calendar year 2000 (or extensions thereto due to force majeure events), gas production by Shell from its offshore Gulf of Mexico producing properties and leases is 950 million cubic feet per day for 180 not-necessarily-consecutive days or 375 billion cubic feet on a cumulative basis. Shell will earn another 3 million convertible Contingency Units if at any point during calendar year 2001 (or extensions thereto due to force majuere events) such gas production is 900 million cubic feet per day for 180 not-necessarily-consecutive days or 350 billion cubic feet on a cumulative basis. If either or both of the preceding performance tests is not met but Shell's Offshore Gulf of Mexico gas production reaches 725 billion cubic feet on a cumulative basis in calendar years 2000 and 2001 (or extensions thereto due to force majuere events), Shell would still earn 6 million non-distribution bearing, convertible Contingency Units. If all of the Contingency Units are earned, 1 million Contingency Units would convert into Common Units on August 1, 2002 and 5 million Contingency Units would convert into Common Units on August 1, 2003. The Contingency Units do not accrue distributions and are not entitled to cash distributions until conversion into Common Units. Tejas Energy's ownership interest in the Company would then increase to approximately 23.2%.

Under the rules of the New York Stock Exchange, conversion of the Special Units into Common Units requires approval of the Company's Unitholders. The General Partner has agreed to call a special meeting of the Unitholders for the purpose of soliciting such approval. EPC Partners II, Inc. ("EPC II"), which owns in excess of 81% of the outstanding Common Units, has agreed to vote its Units in favor of such approval, which will satisfy the approval requirement.

6. DISTRIBUTIONS

On January 12, 1999, the Company declared a quarterly distribution of $.45 per Unit for the fourth quarter of 1998, which was paid on February 11, 1999 to all Unitholders of record on January 29, 1999. The Company declared its distribution for the first quarter of 1999 on April 16, 1999 in the amount of $.45 per Common Unit. The first quarter 1999 distribution was paid on May 12, 1999 to Common Unitholders of record on April 30, 1999. The Company declared a $.45 per Common Unit distribution for the second quarter of 1999 on July 16, 1999. The second quarter 1999 distribution was paid on August 11, 1999 to Common Unitholders of record on July 30, 1999. The third quarter 1999 distribution of $.45 per Unit was declared on October 15, 1999 and was paid on November 10, 1999 to all Unitholders of record at the close of business on October 29, 1999.

7. SUPPLEMENTAL CASH FLOW DISCLOSURE

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

	Nine Months Ended September 30, 1998	1999
(Increase) decrease in:		
Accounts receivable	$ 19,879	$ (48,448)
Inventories	(41,985)	(64,992)
Prepaid and other current assets	(550)	(4,647)
Other assets	(494)	(1,757)
Increase (decrease) in:		
Accounts payable - trade	(27,255)	43,944
Accrued gas payable	(8,437)	61,474
Accrued expenses	(4,503)	1,236
Other current liabilities	(12,479)	(21,595)
Other liabilities		539
Net effect of changes in operating accounts	$ (75,824)	$ (34,246)

8. RECENTLY ISSUED ACCOUNTING STANDARDS

On June 6, 1999, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 137, "Accounting for Derivative Instruments and Hedging Activities-Deferral of the Effective Date of FASB Statement No. 133-an amendment of FASB Statement No. 133" which effectively delays and amends the application of SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" for one year, to fiscal years beginning after June 15, 2000. Management is currently studying both SFAS No. 137 and SFAS No. 133 for possible impact on the consolidated financial statements.

On April 3, 1998, the American Institute of Certified Public Accountants issued Statement of Position ("SOP") 98-5, "Reporting on the Costs of Start-Up Activities." For years beginning after December 15, 1998, SOP 98-5 generally requires that all start-up costs of a business activity be charged to expense as incurred and any start-up costs previously deferred should be written off as a cumulative effect of a change in accounting principle. Adoption of SOP 98-5 during 1999 did not have a material impact on the consolidated financial statements except for a $4.5 million noncash write-off that occurred on January 1, 1999 of the unamortized balance of deferred start-up costs of BEF, in which the Company owns a 33-1/3% interest. This write-off caused a $1.5 million reduction in the equity in income of unconsolidated affiliates for 1999 and a corresponding reduction in the Company's investment in unconsolidated affiliates.

9. CONCENTRATION OF CREDIT RISK

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

The Company is subject to a number of risks inherent in the industry in which it operates, primarily fluctuating gas and liquids prices and gas supply. The Company's financial condition and results of operations will depend significantly on the prices received for NGLs and the price paid for gas consumed in the NGL extraction process. These prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond the control of the Company. In addition, the Company must continually connect new wells through third-party gathering systems which serve the gas plants in order to maintain or increase throughput levels to offset natural declines in dedicated volumes. The number of wells drilled by third parties will depend on, among other factors, the price of gas and oil, the energy policy of the federal government, and the availability of foreign oil and gas, none of which is in the Company's control.

10. SUBSEQUENT EVENT

Purchase of Lou-Tex Pipeline

On July 27, 1999, the Company announced the execution of a letter of intent to acquire a Louisiana and Texas pipeline asset from Concha Chemical Pipeline Company ("Concha"), an affiliate of Shell, for an undisclosed amount of cash. The pipeline being acquired, referred to as the Lou-Tex pipeline, is 263 miles of 10" pipeline from Sorrento, Louisiana to Mont Belvieu, Texas. The Lou-Tex pipeline is currently dedicated to the transportation of chemical grade propylene from Sorrento to the Mont Belvieu area. The acquisition of the Lou-Tex pipeline is the first step in the Company's development of a $210 million, 160,000 barrel per day gas liquids pipeline system. This larger system will link growing supplies of NGLs produced in Louisiana and Mississippi with the principal NGL markets on the United States Gulf Coast. The completion of the Lou-Tex transaction is subject to the successful negotiation of definitive agreements, approval of those agreements by the respective managements and regulatory approvals. This purchase of the pipeline asset from Concha is expected to be completed in the fourth quarter of 1999. The development of the expanded Lou-Tex gas liquids pipeline system is expected to be completed in the second half of 2000.

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

For the Interim Periods ended September 30, 1999 and 1998

The following discussion and analysis should be read in conjunction with the unaudited consolidated financial statements and notes thereto of Enterprise Products Partners L.P. ("Enterprise" or the "Company") included elsewhere herein.

The Company

The Company is a leading integrated North American provider of processing and transportation services to domestic and foreign producers of natural gas liquids ("NGLs") and other liquid hydrocarbons and domestic and foreign consumers of NGLs and liquid hydrocarbon products. The Company manages a fully integrated and diversified portfolio of midstream energy assets and is engaged in NGL processing and transportation through direct and indirect ownership and operation of NGL fractionators. It also manages NGL processing facilities, storage facilities, pipelines, and rail transportation facilities, and methyl tertiary butyl ether ("MTBE") and propylene production and transportation facilities in which it has a direct and indirect ownership. As a result of the recent Tejas Natural Gas Liquids, LLC ("TNGL") acquisition described below, the Company is also engaged in natural gas processing in Louisiana and Mississippi.

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 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 quarterly report include the assets and operations of the Operating Partnership and its subsidiaries as well as the predecessors of the Company.

General

The Company (i) processes natural gas; (ii) fractionates for a processing fee mixed NGLs produced as by-products of oil and natural gas production into their component products: ethane, propane, isobutane, normal butane and natural gasoline; (iii) converts normal butane to isobutane through the process of isomerization; (iv) produces MTBE from isobutane and methanol; and (v) transports NGL products to end users by pipeline and railcar. The Company also separates high purity propylene from refinery-sourced propane/propylene mix and transports high purity propylene to plastics manufacturers by pipeline. Products processed by the Company generally are used as feedstocks in petrochemical manufacturing, in the production of motor gasoline and as fuel for residential and commercial heating.

The Company's NGL processing operations are concentrated in the Texas, Louisiana, and Mississippi Gulf Coast area. A large portion is concentrated in Mont Belvieu, Texas, which is the hub of the domestic NGL industry and is adjacent to the largest concentration of refineries and petrochemical plants in the United States. The facilities we operate at Mont Belvieu include: (i) one of the largest NGL fractionation facilities in the United States with an average production capacity of 210,000 barrels per day; (ii) the largest butane isomerization complex in the United States with an average isobutane production capacity of 80,000 barrels per day; (iii) one of the largest MTBE production facilities in the United States with an average production capacity of 14,800 barrels per day; and (iv) two propylene fractionation units with an average combined production capacity of 31,000 barrels per day. 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% economic interest (see Recent Acquisitions below); 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 33-1/3% interest; and one of its three isomerization units and one deisobutanizer which are held under long-term leases with purchase options. The Company also owns and operates approximately 35 million barrels of storage capacity at Mont Belvieu and elsewhere that are an integral part of its processing operations, a network of approximately 500 miles of pipelines along the Gulf Coast and a NGL fractionation facility in Petal, Mississippi with an average production capacity of 7,000 barrels per day. The Company also leases and operates one of only two commercial NGL import/export terminals on the Gulf Coast.

As a result of the Tejas Natural Gas Liquids, LLC ("TNGL") acquisition, the Company acquired, effective August 1, 1999, a 20-year natural gas processing agreement with Shell Oil Company ("Shell") for the rights to process its current and future natural gas production from the state and federal waters of the Gulf of Mexico and varying interests in 11 natural gas processing plants (including one under construction) with a combined gross capacity of 11.0 billion cubic feet per day ("Bcfd") and net capacity of 3.1 Bcfd; four NGL fractionation facilities with a combined gross capacity of 281,000 BPD and net capacity of 131,500 BPD; four NGL storage facilities with approximately 29.5 million barrels of gross capacity and 8.8 million barrels of net capacity; and over 2,100 miles of NGL pipelines (including a 11.5% interest in Dixie Pipeline).

Recent Acquisitions

Tejas Natural Gas Liquids, LLC. As noted above, effective August 1, 1999, the Company acquired TNGL from Tejas Energy, LLC ("Tejas Energy"), an affiliate of Shell, in exchange for 14.5 million non-distribution bearing, convertible special partner units of the Company and a cash payment of $166 million. The Company has also agreed to issue up to 6.0 million non-distribution bearing, convertible special units to Tejas Energy in the future if the volumes of natural gas that the Company processes for Shell and its affiliates reach certain agreed upon levels in 2000 and 2001. The businesses acquired from Tejas Energy include natural gas processing and NGL fractionation, transportation and storage in Louisiana and Mississippi and its NGL supply and marketing business. As described in General above, the assets acquired include varying interests in 11 natural gas processing plants, four NGL fractionation facilities, four NGL storage facilities and over 2,100 miles of NGL pipelines.

The Company's major customer related to the TNGL assets is Shell. Under the terms of a 20-year processing agreement with Shell, the Company has the right to process substantially all of Shell's current and future natural gas production from the Gulf of Mexico. This includes natural gas production from the developments currently referred to as deepwater.

Natural gas processing plants are generally located near the production area. When produced at the wellhead, natural gas generally must be processed to separate the merchantable, pipeline quality natural gas (principally methane), from NGLs and other impurities. Wet or rich natural gas normally must be processed to render the natural gas acceptable for transport in the nation's pipeline system and to meet specifications required by local natural gas distribution companies. After being extracted in the field, mixed NGLs, sometimes referred to as "y-grade" or "raw make" are typically transported to a central facility for fractionation and subsequent sale.

Mont Belvieu NGL Fractionation facility. Effective July 1, 1999, a subsidiary of the Operating Partnership acquired an additional 25% interest in the Mont Belvieu NGL fractionation facility from Kinder Morgan for a purchase price of approximately $41 million in cash and the assumption of $4 million in debt. An additional 0.5% interest in the same facility was purchased from EPCO for a cash purchase price of $0.9 million. These acquisitions increased our effective economic interest in the Mont Belvieu NGL fractionation facility from 37.0% to 62.5%.

Industry Environment

Because certain NGL products compete with other refined petroleum products in the fuel and petrochemical feedstock markets, NGL product prices are set by or in competition with refined petroleum products. Increased production and importation of NGLs and NGL products in the United States may decrease NGL product prices in relation to refined petroleum alternatives and thereby increase consumption of NGL products as NGL products are substituted for other more expensive refined petroleum products. Conversely, a decrease in the production and importation of NGLs and NGL products could increase NGL product prices in relation to refined petroleum product prices and thereby decrease consumption of NGLs. However, because of the relationship of crude oil and natural gas production to NGL production, the Company believes any imbalance in the prices of NGLs and NGL products and alternative products would be temporary.

Historically, when the price of crude oil is a multiple of ten or more to the price of natural gas (i.e., crude oil $20 per barrel and natural gas $2 per thousand cubic feet ("MCF")), NGL pricing has been strong due to increased use in manufacturing petrochemicals. In 1998, the industry experienced an annualized multiple of approximately six (i.e., crude oil $12 per barrel and natural gas $2 per MCF), which caused petrochemical manufacturing demand to change from reliance on NGLs to a preference for crude oil derivatives. This change resulted in the lowering of both the production and pricing of NGLs. In the NGL industry, revenues and cost of goods sold can fluctuate significantly up or down based on current NGL prices. However, operating margins will generally remain constant except for the effect of inventory price adjustments or increased operating expenses.

NGL Fractionation

The profitability of this business unit depends on the volume of mixed NGLs that the Company processes for its toll customers and the level of toll processing fees charged to its customers. The most significant variable cost of fractionation is the cost of energy required to operate the units and to heat the mixed NGLs to effect separation of the NGL products. The Company is able to reduce its energy costs by capturing excess heat and re-using it in its operations. Additionally, the Company's NGL fractionation processing contracts typically contain escalation provisions for cost increases resulting from increased variable costs, including energy costs.

Effective July 1, 1999, the Company's ownership interest in the Mont Belvieu NGL fractionation facility increased to an effective 62.5% from 37.0%. Since the acquisition, the Company's 62.5% interest in the results of operations of the fractionation facility have been included in consolidated operations. Prior to the acquisition, the Company's 12.5% direct economic interest was included in consolidated operations, and its effective 24.5% economic interest was recorded as equity income.

Isomerization

The profitability of this business unit depends on the volume of normal butane that the Company isomerizes (i.e., converts) into isobutane for its toll processing customers, the level of toll processing fees charged to its customers, and the margins generated from selling isobutane to merchant customers. The Company's toll processing customers pay the Company a fee for isomerizing their normal butane into isobutane. In addition, the Company sells isobutane that it obtains by isomerizing normal butane into isobutane, fractionating mixed butane into isobutane and normal butane, or purchasing isobutane in the spot market. The Company determines the optimal sources for isobutane to meet sales obligations based on current and expected market prices for isobutane and normal butane, volumes of mixed butane held in inventory, and estimated costs of isomerization and mixed butane fractionation.

The Company purchases most of its imported mixed butanes between the months of February and October. During these months, the Company is able to purchase imported mixed butanes at prices that are often at a discount to posted market prices. Because of its storage capacity, the Company is able to store these imports until the summer months when the spread between isobutane and normal butane typically widens or until winter months when the prices of isobutane and normal butane typically rise. As a result, inventory investment is generally at its highest level at the end of the third quarter of the year. Should this spread not materialize, or in the event absolute prices decline, margins generated from selling isobutane to merchant customers may be negatively affected.

Propylene Fractionation

The profitability of this business unit depends on the volumes of refinery-sourced propane/propylene mix that the Company processes for its toll customers, the level of toll processing fees charged to its customers and the margins associated with buying refinery-sourced propane/propylene mix and selling high purity propylene to meet sales contracts with non-tolling customers.

Pipelines

The Company operates both interstate and intrastate NGL product and propylene pipelines. The Company's interstate pipelines are common carriers and must provide service to any shipper who requests transportation services at rates regulated by the Federal Energy Regulatory Commission ("FERC"). The Company's intrastate common carrier pipelines are regulated by the State of Louisiana. The profitability of this business unit is primarily dependent on pipeline throughput volumes.

Gas Processing

As a result of the TNGL acquisition, the Company is now engaged in natural gas processing in Louisiana and Mississippi via ownership interests in eleven plants. The profitability of the natural gas processing plants is primarily dependent on the volume of NGLs extracted from the natural gas streams and the pricing of NGLs and natural gas in the marketplace.

Unconsolidated Affiliates

At September 30, 1999, the Company's significant unconsolidated affiliates accounted for using the equity method were BEF, BRF, BRPC, EPIK, Wilprise, Tri-States, Belle Rose, and Promix. BEF owns the MTBE production facility operated by the Company at its Mont Belvieu complex. BRF owns a NGL fractionation facility in southeastern Louisiana that began operations in the third quarter of 1999. BRPC is a newly-formed joint venture (August 1999) between the Operating Partnership and Exxon Chemical Company ("Exxon") which owns a propylene concentration unit under construction in southeastern Louisiana. The Company holds a 30% economic interest in BRPC. Management anticipates that operations will commence at this plant in the third quarter of 2000. EPIK owns a refrigerated NGL marine terminal loading facility located on the Houston ship channel. An expansion of EPIK's NGL marine terminal loading facility is under way and is scheduled for completion in the fourth quarter of 1999. Wilprise owns a NGL pipeline in Louisiana which started operations in the third quarter of 1999 in conjunction with the start-up of the BRF fractionator. Tri-States owns a NGL pipeline in Louisiana, Mississippi, and Alabama which became operational in March 1999. Effective with the TNGL acquisition, the Company acquired an equity interest in Belle Rose and Promix. Belle Rose owns a NGL pipeline system in south Louisiana. The Company owns 41.7% of Belle Rose. Promix owns a NGL fractionation and related storage facilities in south Louisiana. The Company holds a 33-1/3% interest in Promix. In connection with the TNGL acquisition, the Company acquired an additional 16-2/3% of Tri-States bringing the total ownership interest to the current 33-1/3%.

As of September 30, 1999, the Company had two investments accounted for using the cost method. These were VESCO and Dixie. VESCO owns a natural gas processing plant, fractionation and storage facilities, and a gas gathering pipeline system in Louisiana. The Company holds a 13.1% economic interest in VESCO. The Dixie investment consists of an 11.5% interest in a corporation owning a 1,300 mile propane pipeline and the associated facilities extending from Mont Belvieu, Texas to North Carolina.

Results of Operations

Historically, the Company has had only one reportable segment: NGL Operations. The operating margin of this segment has been reported on under five distinct business units: NGL Fractionation, Isomerization, Propylene Fractionation, Pipeline, and Storage and Other Plants. With the acquisition of TNGL, management has opted to add a sixth business unit: TNGL Operations. In addition, with the growth of the Company's equity method investments, Equity in income of unconsolidated affiliates has been included in operating margin in order to provide a more comprehensive view of the Company's results of operations. For the future, due to the growing complexity of the Company's operations with the acquisition of TNGL late in the third quarter of 1999, management is currently studying alternative reporting methods such as reporting results of operations using multiple segments.

The Company's operating margins by business unit for the three and nine month periods ended September 30, 1998 and 1999 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	1998	1999	1998	1999
Operating Margin:				
NGL Fractionation	$ 1,274	$ 1,369	$ 2,812	$ 2,901
Isomerization	2,267	17,731	15,729	35,727
Propylene Fractionation	3,538	5,374	8,004	16,813
Pipeline	3,221	2,553	10,268	6,268
TNGL Operations		13,648		13,648
Storage and Other Plants	1,123	51	4,462	185
Equity in Income of Unconsolidated Affiliates	4,171	3,148	7,591	10,824
Total	$ 15,594	$ 43,874	$ 52,099	$ 83,133

The Company's plant production data (in thousands of barrels per day or "MBPD") for the three and nine month periods ended September 30, 1998 and 1999 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	1998	1999	1998	1999
Plant Production Data :				
TNGL Equity NGL Production		63		63
NGL Fractionation	180	149	197	155
Isomerization	65	77	65	73
MTBE	14	12	13	13
Propylene Fractionation	26	26	26	27

The Company's equity in income of unconsolidated affiliates (in thousands) for the three and nine month periods ended September 30, 1998 and 1999 were as follows:

	Three Months ended September 30,		Nine Months ended September 30,	
	1998	1999	1998	1999
BEF	$ 3,355	$ 2,519	$ 6,609	$ 4,756
MBA	862	72	4,305	1,256
BRF		(258)		(544)
BRPC		4		4
EPIK	(46)	59	(90)	236
Entell		258		1,389
Wilprise		(130)		(130)
Tri-States		472		472
Belle Rose		245		245
Promix		(93)		(93)
Total	$ 4,171	$ 3,148	$ 10,824	$ 7,591

Three Months Ended September 30, 1999 Compared with Three Months Ended September 30, 1998

Revenues; Costs and Expenses

The Company's revenues increased to $445.0 million in 1999 compared to $168.8 million in 1998. The Company's costs and expenses increased to $404.4 million in 1999 compared to $156.9 million in 1998. Operating margin increased to $43.9 million in 1999 compared to $15.6 million in 1998. The primary reasons for the increase in operating margins are an improvement in the isomerization business and the addition of the operating results of the TNGL assets.

NGL Fractionation. Operating margin from NGL fractionation, which reflects earnings from the Company's Mont Belvieu NGL fractionation assets, was $1.4 million for the third quarter of 1999 compared to $1.3 million for the third quarter of 1998. For the quarter, NGL fractionation volumes at Mont Belvieu averaged 149 MBPD compared to 180 MBPD for the same period in 1998. The slight increase in operating margin for the quarter was principally due to the Company's acquisition of an additional ownership interest in the fractionation from Kinder Morgan and EPCO, offset by lower volumes fractionated. The lower fractionation rates are attributable to the short-term diversion of customer volumes to competitors. The Company fully expects that the diverted volumes will be recovered.

Isomerization. The Company's margin in isomerization was $17.7 million for the third quarter of 1999 versus $2.3 million for the third quarter of 1998. Plant production volumes for the third quarter of 1999 averaged 77 MBPD as compared to 65 MBPD for the same period in 1998. The margin improvement was attributable to the increase in plant production volumes, a stronger price environment for normal butane and isobutane during the third quarter of 1999 which benefited the merchant portion of this business and non-recurring inventory write-downs which impaired margins in the third quarter of 1998. The operating margin for 1999 included a $0.7 million benefit from the amortization of the deferred gain associated with the sale and leaseback of one of the Company's isomerization units. Excluding this benefit, the operating margin for 1999 would have been $17.0 million as compared to $2.3 million in 1998.

Isobutane volumes from tolling and merchant activities for the third quarter of 1999 averaged 98 MBPD as compared to 107 MBPD for the same period in 1998. Average daily toll processing volumes were 58 MBPD in 1999 and 1998. Isobutane volumes related to merchant activities were 40 MBPD in 1999 and 49 MBPD in 1998. Isobutane merchant volumes decreased in the third quarter of 1999 compared to third quarter of 1998 due to lower margins on isobutane sales relative to normal butane sales. The average spread between isobutane and normal butane decreased from a positive 2.3 cents per gallon ("CPG") in the third quarter of 1998 to a negative 1.2 CPG in the third quarter of 1999.

Propylene Fractionation. The Company's operating margin from propylene fractionation for the third quarter of 1999 increased to $5.4 million from $3.5 million for the third quarter of 1998. Propylene fractionation for both periods averaged 26 MBPD. The earnings improvement was primarily attributable to the Company's actions in the merchant portion of the business to match the volume, timing and price of feedstock purchases with sales of the product. Polymer grade propylene prices for the third quarter of 1999 were significantly stronger at 15.7 cents per pound ("CPP") versus 13.7 CPP in the third quarter of 1998. The increase in propylene prices in general for 1999 is attributable to higher crude oil prices and increased global propylene demand.

Pipeline. Operating margin from pipeline operations for the third quarter of 1999 was $2.6 million as compared to $3.2 million for the third quarter of 1998. The decrease in operating margin is primarily attributable to lower butane import volume in the third quarter of 1999 as compared to 1998. The lower volumes led to a $0.3 million decrease in the operating margin in 1999 versus 1998. A strengthening of normal butane prices worldwide has led to a decrease in the availability of import volumes coming to the U.S. Gulf Coast. Throughput for the third quarter of 1999 averaged 192 MBPD as compared to 193 MBPD for the same period in 1998.

TNGL Operations. The operating margin from the assets acquired from TNGL in the third quarter 1999 was $13.6 million. Since the effective date of the TNGL acquisition was August 1, 1999, the operating margin included in the Company's results of operations was for the months of August and September. Gas Processing produced an operating margin of approximately $9.2 million. NGL fractionation generated an operating margin of $4.1 million. The Pipelines and Other assets produced an operating margin of $0.3 million.

Gas Processing is comprised of interests in eleven natural gas processing plants (one of which is under construction) with 11 billion cubic feet per day ("Bcfd") of gross capacity and 3.1 Bcfd of net capacity to the Company's interest anchored by a 20-year natural gas processing agreement with Shell (the "Shell Agreement"). The Company is operator of four of these facilities. Its major customer is Shell. Under the terms of a 20-year processing agreement with Shell, the Company has the right to process substantially all of Shell's current and future natural gas production from the Gulf of Mexico. This includes natural gas production from the developments currently referred to as deepwater. Also included in Gas Processing is the Tebone NGL fractionation facility. This fractionation facility is an integral part of the Tebone and North Terrebone Gas Processing facility. The Tebone NGL fractionation facility was built to receive raw make from the North Terrebone Gas Processing facility and has a rated capacity of 30 MBPD. During the months of August and September, the Gas Processing facilities produced NGLs at a rate of 63 MBPD with the Tebone fractionator operating at 29 MBPD.

NGL fractionation business is comprised of the Norco NGL fractionation facility located in Louisiana. This facility is wholly owned by the Company and has a capacity of 60 MBPD. During the months of August and September, the Norco NGL fractionation plants operated a rate of 47 MBPD.

Pipeline and Other TNGL assets is primarily composed of varying ownership interests in NGL and NGL product pipelines and storage assets located in southern Louisiana.

Selling, General and Administrative Expenses

Selling, general and administrative expenses decreased $0.6 million to $3.2 million in 1999 from $3.8 million in 1998. The 1998 charges included $0.8 million in one-time expenses related to the initial public offering in July 1998. This amount was offset by a $0.2 million increase in the monthly charge from EPCO. On July 7, 1999, the Audit and Conflicts Committee of Enterprise Products GP, LLC (the "general partner") authorized an increase in the administrative services fee to $1.1 million per month in accordance with the EPCO Agreement from the initial rate of $1.0 million per month. The increased fees were effective August 1, 1999.

Interest Expense

Interest expense for the second quarter was $4.0 million in 1999 and $2.5 million in 1998. This increase is principally due to the increased level of average debt outstanding during the third quarter of 1999 attributable to the borrowings associated with the TNGL and Mont Belvieu fractionation facility acquisitions. Of the total debt outstanding at September 30, 1999 of $390 million, approximately $208 million is directly related to these two acquisition transactions.

Equity Income in Unconsolidated Affiliates

Equity income in unconsolidated affiliates was $3.1 million in 1999 compared to $4.2 million in 1998. Equity income from BEF decreased from $3.4 million in the third quarter of 1998 to $2.5 million in the comparable period for 1999. The decrease of $0.9 million is primarily attributable to downtime associated with maintenance activities in July 1999. As a result of the acquisition of the remaining MBA ownership interests in the Mont Belvieu fractionator on July 1, 1999 and subsequent consolidation of operating results, equity income from MBA ceased effective on that date. The third quarter 1998 equity income amount includes $0.9 million from MBA. EPIK showed a slight increase over the third quarter of 1998 with $0.1 million in equity income versus a loss of $0.1 million in the prior period. Wilprise showed a slight loss during the quarter of $0.1 million with the BRF fractionation facility evidencing a loss as well of $0.3 million. Both the Wilprise pipeline and the BRF fractionation facility started operations in the third quarter of 1999.

The Company acquired equity interests in other entities as a result of the TNGL acquisition. Among these entities were Belle Rose (equity income of $0.2 million) and Promix (equity loss of $0.1 million). With the acquisition of an additional 16-2/3% in Tri-States, the Company obtained an equity interest of 33-1/3%. This investment contributed $0.5 million in equity income.

Nine Months Ended September 30, 1999 Compared with Nine Months Ended September 30, 1998

Revenues; Costs and Expenses

The Company's revenues increased by 35% to $771.4 million in 1999 compared to $573.5 million in 1998. The Company's costs and expenses decreased by 32% to $688.3 million in 1999 compared to $521.4 million in 1998. Operating margin increased by 60% to $83.1 million in 1999 compared to $52.1 million in 1998. The primary reasons for the increase in operating margins are an improvement in the isomerization and propylene fractionation business areas and the addition of the operating results of the TNGL assets.

NGL Fractionation. The Company's operating margin for NGL fractionation was $2.9 million for 1999 versus $2.8 million for 1998. Average daily fractionation volumes decreased from 197 MBPD in 1998 to 155 MBPD in 1999. Fractionation volumes are lower in 1999 as compared to 1998 due primarily to ethane rejection, downtime associated with preventative maintenance activities, lower natural gas production caused by depressed oil and gas prices in early 1999, and the short-term diversion of customer volumes to a competitor. During the first quarter of 1999, natural gas prices remained higher than the energy unit equivalent of ethane; therefore, upstream natural gas processing plants rejected ethane which reduced the volumes delivered to Company facilities for fractionation services. The Company took advantage of the reduced demand for its fractionation services during the first quarter of 1999 to perform certain preventative maintenance procedures on one of its fractionation facilities that are generally required every two to three years. During the second quarter of 1999, volumes were reduced due to the short-term diversion of customer volumes to a competitor. Management expects that these volumes will be fully recovered.

Isomerization. The Company's operating margin for isomerization increased to $35.8 million in 1999 compared to $15.7 million in 1998. The operating margin for 1999 included a $2.0 million benefit from the amortization of the deferred gain associated with the sale and leaseback of one of the Company's isomerization units. The margin improvement is primarily attributable to a stronger price environment for normal butane and isobutane during 1999 which benefited the merchant portion of this business and non-recurring inventory write-downs which impaired margins in 1998. Excluding this benefit, the operating margin for 1999 would have been $33.8 million as compared to $15.7 million in 1998. Isobutane volumes from tolling and merchant activities for 1999 averaged 100 MBPD as compared to 102 MBPD for the same period in 1998. Average daily toll processing volumes were 57 MBPD in 1999, or 73% of total volumes produced, compared to 56 MBPD in 1998, or 86% of total volumes produced. Isobutane volumes related to merchant activities were 43 MBPD in 1999 and 45 MBPD in 1998.

Propylene Fractionation. The Company's operating margin increased to $16.8 million in 1999 from $8.0 million in 1998. Propylene production averaged 27 MBPD in 1999 as compared to 26 MBPD in 1998. The earnings improvement was primarily attributable to the Company's actions to minimize risk in the merchant portion of this business by matching the volume, timing and price of feedstock purchases with sales of end products. The operating margin also benefited from an increase in production volumes associated with spot business caused by increased demand for polymer grade propylene.

Pipeline. The Company's operating margin from pipeline operations was $6.3 million in 1999 compared to $10.3 million in 1998. Throughput for 1999 averaged 184 MBPD as compared to 198 MBPD for the same period in 1998. The decrease in throughput was primarily attributable to a decrease in import volumes. The decrease in Pipeline margin is principally related to the Company's contribution of certain wholly-owned pipeline assets, in the first quarter of 1999, and its export loading facility, in June 1998 to joint ventures in which the Company owns a 50% interest. As a result, the earnings from these assets since the time of their contribution are included in equity income from unconsolidated affiliates as prescribed by the equity method of accounting rather than in earnings from consolidated pipeline operations. This change in accounting treatment accounts for approximately $2.8 million of the decrease.

TNGL Operations. The operating margin from the assets acquired from TNGL in the third quarter 1999 was $13.6 million. Since the effective date of the TNGL acquisition was August 1, 1999, the operating margin included in the Company's results of operations was for the months of August and September. Gas Processing produced an operating margin of approximately $9.2 million. NGL fractionation generated an operating margin of $4.1 million. The Pipelines and Other assets produced an operating margin of $0.3 million.

Gas Processing is comprised of interests in eleven natural gas processing plants (one of which is under construction) with 11 billion cubic feet per day ("Bcfd") of gross capacity and 3.1 Bcfd of net capacity to the Company's interest anchored by a 20-year natural gas processing agreement with Shell (the "Shell Agreement"). The Company is operator of four of these facilities. Its major customer is Shell. Under the terms of a 20-year processing agreement with Shell, the Company has the right to process substantially all of Shell's current and future natural gas production from the Gulf of Mexico. This includes natural gas production from the developments currently referred to as deepwater. Also included in Gas Processing is the Tebone NGL fractionation facility. This fractionation facility is an integral part of the Tebone and North Terrebone Gas Processing facility. The Tebone NGL fractionation facility was built to receive raw make from the North Terrebone Gas Processing facility and has a rated capacity of 30 MBPD. During the months of August and September, the Gas Processing facilities produced NGLs at a rate of 63 MBPD with the Tebone fractionator operating at 29 MBPD.

NGL fractionation business is comprised of the Norco NGL fractionation facility located in Louisiana. This facility is wholly owned by the Company and has a capacity of 60 MBPD. During the months of August and September, the Norco NGL fractionation plants operated a rate of 47 MBPD.

Pipeline and Other TNGL assets is primarily composed of varying ownership interests in NGL and NGL product pipelines and storage assets located in southern Louisiana.

Selling, General and Administrative Expenses

Selling, general and administrative expenses decreased $6.2 million to $9.2 million in 1999 from $15.4 million in 1998. This decrease was primarily due to the adoption of the EPCO Agreement in July 1998 in conjunction with the Company's initial public offering ("IPO") which fixed reimbursable selling, general, and administrative expenses at an initial $1.0 million per month.

On July 7, 1999, the Audit and Conflicts Committee of the general partner authorized an increase in the administrative services fee to $1.1 million per month in accordance with the EPCO Agreement. The increased fees are effective August 1, 1999.

Interest Expense

Interest expense was $8.0 million in 1999 and $13.3 million in 1998. This decrease was principally due to the reduced level of average debt outstanding during the first quarter of 1999 attributable to the retirement of debt in July 1998 using proceeds from the Company's IPO. The decrease was muted, however, due to a substantial increase in the average debt outstanding in the third quarter of 1999 due to the borrowings associated with the TNGL and Mont Belvieu fractionation facility acquisitions.

Equity Income in Unconsolidated Affiliates

Equity income in unconsolidated affiliates was $7.6 million in 1999 compared to $10.8 million in 1998. Equity income from BEF decreased from $6.6 million in 1998 to $4.8 million in 1999. Equity income from BEF for both periods was affected by required annual maintenance on the Company's MTBE facility that generally takes the unit out of production for approximately three weeks. Equity income from BEF during 1999 also includes a $1.5 million non-cash charge for the cumulative effect of a change in accounting principal related to the write-off of deferred start-up costs as prescribed by generally accepted accounting principles. Equity income from MBA decreased to $1.3 million in 1999 from $4.3 million in 1998 due to decreased throughput caused by ethane rejection and downtime associated with preventative maintenance activities. In addition, as a result of the acquisition of the remaining MBA ownership interests in the Mont Belvieu fractionator on July 1, 1999 and subsequent consolidation of operating results, equity income from MBA ceased effective on that date. The 1998 results for MBA are for a nine-month period whereas the 1999 results reflect a six-month period. The third quarter results of operations are now consolidated and included in NGL Fractionation. EPIK showed a slight increase over the 1998 with $0.2 million in equity income versus a loss of $0.1 million in the prior period. The 1998 results for EPIK reflected its first quarter in existence whereas the 1999 results are for nine months. Wilprise showed a slight loss of $0.1 million with the BRF fractionation facility generating a loss of $0.5 million. Both the Wilprise pipeline and the BRF fractionation facility started operations in the third quarter of 1999. Equity income from Entell was $1.4 million through July 31, 1999. Effective August 1, 1999, as a result of the TNGL acquisition, the results of operations for Entell are now included in consolidated pipeline revenues. Consolidation of operating results is necessary under generally accepted accounting principles since the combined interests of the Company now equal 100% (prior to August 1, 1999, the Company held a 50% interest with TNGL holding the remaining 50%).

The Company acquired equity interests in other entities as a result of the TNGL acquisition. Among these entities were Belle Rose (equity income of $0.2 million) and Promix (equity loss of $0.1 million). With the acquisition of an additional 16-2/3% in Tri-States, the Company obtained an equity interest of 33-1/3%. This investment contributed $0.5 million in equity income.

Financial Condition and Liquidity

General

The Company's primary cash requirements, in addition to normal operating expenses, are debt service, maintenance capital expenditures, expansion capital expenditures, and quarterly distributions to the partners. The Company expects to fund future cash distributions and maintenance capital expenditures with cash flows from operating activities. Capital expenditures for future expansion activities and asset acquisitions are expected to be funded with cash flows from operating activities and borrowings under the revolving bank credit facilities.

Cash flows from operating activities were a $50.1 million inflow for the first nine months of 1999 compared to a $43.9 million outflow for the comparable period of 1998. Cash flows from operating activities primarily reflect the effects of net income, depreciation and amortization, extraordinary items, equity income of unconsolidated affiliates and changes in working capital. Net income increased significantly as a result of improved overall margins and the TNGL acquisition. Depreciation and amortization increased by $2.5 million in 1999 primarily as a result of additional capital expenditures and the TNGL and Mont Belvieu fractionator acquisitions (the "acquisitions") in the third quarter of 1999. Amortization expense increased by $0.7 million due to the amortization of the excess cost recorded in connection with acquisitions. The excess cost associated with the acquisitions will be amortized over a 20-year period at approximately $0.4 million per month. The net effect of changes in operating accounts from year to year is generally the result of timing of NGL sales and purchases near the end of the period.

Cash outflows for investing activities were $255.8 million in 1999 and $48.8 million for the comparable period of 1998. Cash outflows included capital expenditures of $10.6 million for 1999 and $7.2 million for 1998. Included in the capital expenditures amounts are maintenance capital expenditures of $1.7 million for 1999 and $5.6 million for 1998. Investing cash outflows in 1999 also included $58.4 million in advances to and investments in unconsolidated affiliates versus $20.0 million for the comparable period of 1998. The $38.4 million increase stems primarily from contributions made to the Wilprise, Tri-States, BRF, and BRPC joint ventures located in Louisiana. Also, the Company received $16.7 million in payments on notes receivable from the BEF and MBA notes purchased during 1998 with the proceeds of the Company's IPO. In conjunction with the acquisition of the MBA interest in the Mont Belvieu fractionation facility, $5.8 million was received during the third quarter 1999 from MBA for the balance of the Company's note receivable. The $9.8 million outstanding balance of notes receivable from unconsolidated affiliates relates to the participation in the BEF note. This balance will be collected in equal installments of approximately $3.3 million each at the end of November 1999, February 2000 and May 2000.

Cash outflows for investing activities also include the cash payments related to the acquisitions. Per the terms of the TNGL acquisition, $166.0 million was paid to Tejas Energy in September 1999. Likewise, $42.1 million was paid to Kinder Morgan and EPCO to purchase their collective 51% interest in MBA. As described in Note 10 of the notes to the consolidated financial statements, the Company expects to complete a third significant acquisition in the fourth quarter of 1999 - the purchase of a pipeline from Concha Chemical Pipeline Company ("Concha"), an affiliate of Shell, for approximately $100 million in cash. The purchase of the Lou-Tex pipeline is the first step in the Company's development of a $210 million, 160,000 barrel per day gas liquids pipeline system. The completion of the Lou-Tex transaction is subject to the successful negotiation of definitive agreements, approval of those agreements by the respective managements and regulatory approvals. The development of the expanded Lou-Tex gas liquids pipeline system is expected to be completed in the second half of 2000.

Cash flows from financing activities were a $203.3 million inflow in 1999 versus a $66.3 million inflow for the comparable period of 1998. Cash flows from financing activities are affected primarily by repayments of long-term debt, borrowings under the long-term debt agreements and distributions to the partners. The 1998 period reflects the transactions that occurred in the IPO in July 1998. The 1999 period includes $215 million in long-term debt borrowings associated with the TNGL and Mont Belvieu fractionation facility acquisition. Cash flows from financing activities for 1999 also reflected the net purchase of $4.7 million of Common Units by a consolidated trust.

Future Capital Expenditures

The Company currently estimates that its share of remaining expenditures for significant capital projects in fiscal 1999 will be approximately $8.6 million (including $6.2 million for the BRPC propylene concentrator). These expenditures relate to the construction of joint venture projects which will be recorded as additional investments in unconsolidated affiliates. The Company forecasts that an additional $24.3 million will be spent in 1999 on capital projects that will be recorded as property, plant, and equipment (including $10.9 million for the Lou-Tex pipeline and $5.6 million for the construction of gas plants acquired from TNGL). The Company expects to finance these expenditures out of operating cash flows and borrowings under its bank credit facilities. As of September 30, 1999, the Company had $13.2 million in outstanding purchase commitments attributable to its capital projects. Of this amount, $4.7 million is associated with significant capital projects which will be recorded as additional investments in unconsolidated affiliates for accounting purposes.

Distributions from Unconsolidated Affiliates

Distributions to the Company from MBA were $1.9 million in 1999 and $4.7 million in 1998. The level of distributions is lower in 1999 versus 1998 due to lower fractionation margins and the acquisition of the MBA interest in the Mont Belvieu fractionation facility on July 1, 1999. Distributions from BEF in 1999 were $0.3 million versus $1.9 million in 1998. Distributions from BEF are down from 1998 levels due to downtime associated with maintenance activities. Distributions from EPIK in 1999 were $1.6 million. EPIK was formed in the second quarter of 1998 and had no distributions until the third quarter of 1998.

Bank Credit Facility

Existing Bank Credit facility. In July 1998, the Operating Partnership entered into a $200.0 million bank credit facility ("Bank Revolver A") that includes a $50.0 million working capital facility and a $150.0 million revolving term loan facility. The $150.0 million revolving term loan facility includes a sublimit of $30.0 million for letters of credit. As of September 30, 1999, the Company has borrowed $175.0 million under the bank credit facility which is due in July 2000. Management is currently exploring options to convert this short-term debt into long-term debt.

The Company's obligations under the bank credit facility are unsecured general obligations and are non-recourse to the General Partner. Borrowings under the bank credit facility will bear interest at either the bank's prime rate or the Eurodollar rate plus the applicable margin as defined in the facility. The bank credit facility will expire in July 2000 and all amounts borrowed thereunder shall be due and payable at that time. There must be no amount outstanding under the working capital facility for at least 15 consecutive days during each fiscal year.

As amended on July 28, 1999, the existing credit agreement relating to the facility contains a prohibition on distributions on, or purchases or redemptions of, Units if any event of default is continuing. In addition, the bank credit facility contains various affirmative and negative covenants applicable to the ability of the Company to, among other things, (i) incur certain additional indebtedness, (ii) grant certain liens, (iii) sell assets in excess of certain limitations, (iv) make investments, (v) engage in transactions with affiliates and (vi) enter into a merger, consolidation or sale of assets. The bank credit facility requires that the Operating Partnership satisfy the following financial covenants at the end of each fiscal quarter: (i) maintain Consolidated Tangible Net Worth (as defined in the bank credit facility) of at least $250.0 million, (ii) maintain a ratio of EBITDA (as defined in the bank credit facility) to

Consolidated Interest Expense (as defined in the bank credit facility) for the previous 12-month period of at least 3.5 to 1.0 and (iii) maintain a ratio of Total Indebtedness (as defined in the bank credit facility) to EBITDA of no more than 3.0 to 1.0.

A "Change of Control" constitutes an Event of Default under the bank credit facility. A Change of Control includes any of the following events: (i) Dan L. Duncan (and/or certain affiliates) cease to own (a) at least 51% (on a fully converted, fully diluted basis) of the economic interest in the capital stock of EPCO or (b) an aggregate number of shares of capital stock of EPCO sufficient to elect a majority of the board of directors of EPCO; (ii) EPCO ceases to own, through a wholly owned subsidiary, at least 65% of the outstanding membership interest in the General Partner and at least a majority of the outstanding Common Units; (iii) any person or group beneficially owns more than 20% of the outstanding Common Units (excluding certain affiliates of EPCO or Shell Oil Company); (iv) the General Partner ceases to be the general partner of the Company or the Operating Partnership; or (v) the Company ceases to be the sole limited partner of the Operating Partnership.

New Bank Credit facility. On July 28, 1999, the Operating Partnership entered into a $350.0 million bank credit facility ("Bank Revolver B") that includes a $50.0 million working capital facility and a $300.0 million revolving term loan facility. The $300.0 million revolving term loan facility includes a sublimit of $10.0 million for letters of credit. The proceeds of this loan were used to finance the acquisition of TNGL and the MBA ownership interests. Future uses of the remaining credit line include the purchase of the Lou-Tex pipeline (see Note 10).

Borrowings under the bank credit facility will bear interest at either the bank's prime rate or the Eurodollar rate plus the applicable margin as defined in the facility. The bank credit facility will expire in July 2001 and all amounts borrowed thereunder shall be due and payable at that time. There must be no amount outstanding under the working capital facility for at least 15 consecutive days during each fiscal year.

The credit agreement relating to the new facility contains a prohibition on distributions on, or purchases or redemptions of Units if any event of default is continuing. In addition, the bank credit facility contains various affirmative and negative covenants applicable to the ability of the Company to, among other things, (i) incur certain additional indebtedness, (ii) grant certain liens, (iii) sell assets in excess of certain limitations, (iv) make investments, (v) engage in transactions with affiliates and (vi) enter into a merger, consolidation, or sale of assets. The bank credit facility requires that the Operating Partnership satisfy the following financial covenants at the end of each fiscal quarter: (i) maintain Consolidated Tangible Net Worth (as defined in the bank credit facility) of at least $250.0 million, (ii) maintain a ratio of EBITDA (as defined in the bank credit facility) to Consolidated Interest Expense (as defined in the bank credit facility) for the previous 12-month period of at least 3.5 to 1.0 and (iii) maintain a ratio of Total Indebtedness (as defined in the bank credit facility) to EBITDA of no more than 3.0 to 1.0.

A "Change of Control" constitutes an Event of Default under the bank credit facility. A Change of Control includes any of the following events: (i) Dan L. Duncan (and/or certain affiliates) cease to own (a) at least 51% (on a fully converted, fully diluted basis) of the economic interest in the capital stock of EPCO or (b) an aggregate number of shares of capital stock of EPCO sufficient to elect a majority of the board of directors of EPCO; (ii) EPCO ceases to own, through a wholly owned subsidiary, at least 65% of the outstanding membership interest in the General Partner and at least a majority of the outstanding Common Units; (iii) any person or group beneficially owns more than 20% of the outstanding Common Units (excluding certain affiliates of EPCO and Shell Oil Company); (iv) the General Partner ceases to be the general partner of the Company or the Operating Partnership; or (v) the Company ceases to be the sole limited partner of the Operating Partnership.

MTBE Production

The Company owns a 33-1/3% economic interest in the BEF partnership that owns the MTBE production facility located within the Compan's Mont Belvieu complex. The production of MTBE is driven by oxygenated fuels programs enacted under the federal Clean Air Act Amendments of 1990 and other legislation. Any changes to these programs that enable localities to opt out of 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.

On March 25, 1999, the Governor of California ordered the phase-out of MTBE in that state by the end of 2002 due to allegations by several public advocacy and protest groups that MTBE contaminates water supplies, causes health problems and has not been as beneficial in reducing air pollution as originally contemplated. The order also seeks to obtain a waiver of the oxygenate requirement from the federal Environmental Protection Agency ("EPA") in order to facilitate the phase-out; however, due to increasing concerns about the viability of alternative fuels, the California legislature on October 10, 1999 passed the Sher Bill (SB 989) stating that MTBE should be banned as soon as feasible rather than by the end of 2002.

In addition, legislation to amend the federal Clean Air Act of 1990 has been introduced in the U.S. House of Representatives to ban the use of MTBE as a fuel additive within three years. Legislation introduced in the U.S. Senate would eliminate the Clean Air Act's oxygenate requirement in order to assist the elimination of MTBE in fuel. No assurance can be given as to whether this or similar federal legislation ultimately will be adopted or whether Congress or the EPA might takes steps to override the MTBE ban in California.

In November 1998, U.S. EPA Administrator Carol M. Browner appointed a Blue Ribbon Panel (the "Panel") to investigate the air quality benefits and water quality concerns associated with oxygenates in gasoline, and to provide independent advice and recommendations on ways to maintain air quality while protecting water quality. The Panel issued a report on their findings and recommendations in July 1999. The Panel urged the widespread reduction in the use of MTBE due to the growing threat to drinking water sources despite that fact that use of reformulated gasolines have contributed to significant air quality improvements. The Panel credited reformulated gasoline with "substantial reductions" in toxic emissions from vehicles and recommended that those reductions be maintained by the use of cleaner-burning fuels that rely on additives other than MTBE and improvements in refining processes. The Panel stated that the problems associated with MTBE can be characterized as a low-level, widespread problem that had not reached the state of being a public health threat. The Panel's recommendations are geared towards confronting the problems associated with MTBE now rather than letting the issue grow into a larger and worse problem. The Panel did not call for an outright ban on MTBE but stated that its use should be curtailed significantly. The Panel also encouraged a public educational campaign on the potential harm posed by gasoline when it leaks into ground water from storage tanks or while in use. Based on the Panel's recommendations, the EPA will ask Congress for a revision of the Clean Air Act of 1990 that maintains air quality gains and allows for the removal of the oxygenate demand in gasoline.

In light of these developments, the Company is formulating a contingency plan for use of the BEF MTBE facility if MTBE were banned or significantly curtailed. Management is exploring a possible conversion of the BEF facility from MTBE production to alkylate production. At present, the forecasted cost to the Company of this conversion would be in the $20 million to $25 million range with the Company's share being $6.7 million to $8.3 million. Management anticipates that if MTBE is banned alkylate demand will rise as producers use it to replace MTBE as an octane enhancer. Alkylate production would be expected to generate margins comparable to those of MTBE. Greater alkylate production would be expected to increase isobutane consumption nationwide and result in improved isomerization margins for the Company.

Year 2000 Readiness Disclosure

Pursuant to the EPCO Agreement, any selling, general and administrative expenses related to Year 2000 compliance issues are covered by the annual administrative services fee paid by the Company to EPCO. Consequently, only those costs incurred in connection with Year 2000 compliance which relate to operational information systems and hardware will be paid directly by the Company.

Since 1997, EPCO has been assessing the impact of Year 2000 compliance issues on the software and hardware used by the Company. A team was assembled to review and document the status of EPCO's and the Company's systems for Year 2000 compliance. The key information systems reviewed include the Company's pipeline Supervisory Control and Data Acquisition ("SCADA") system, plant, storage, and other pipeline operating systems. In connection with each of these areas, consideration was given to hardware, operating systems, applications, data base management, system interfaces, electronic transmission, and outside vendors. As of October 31, 1999 work is approximately 99% complete in all areas.

As of September 30, 1999, EPCO had spent approximately $326,500 in connection with Year 2000 compliance and has estimated the future costs to approximate $12,000. This cost estimate does not include internal costs of EPCO's previously existing resources and personnel that might be partially used for Year 2000 compliance or cost of normal system upgrades which also included various Year 2000 compliance features or fixes. Such internal costs have been determined to be materially insignificant to the total estimated cost of Year 2000 compliance. These amounts are current cost estimates and actual future costs could potentially be higher or lower than the estimates.

At this time, the Company believes its total cost for known or anticipated remediation of its information systems to make them Year 2000 compliant will not be material to its financial position or its ability to sustain operations. As of September 30, 1999, the Company had incurred expenditures of approximately $1,026,000 in connection with finalizing its Year 2000 compliance project (principally the SCADA system). The Company does not expect any additional material expenditures. This approximate cost does not include the Company's internal costs related to previously existing resources and personnel that might be partially used for remediation of Year 2000 compliance issues. Such internal costs have been determined to be materially insignificant to the total estimated cost of Year 2000 compliance.

The Company relies on third-party suppliers for certain systems, products and services, including telecommunications. There can be no assurance that the systems of other companies on which the Company's systems rely also will timely be compliant or that any such failure to be compliant by another company would not have an adverse effect on the Company's systems. The Company has received certain information concerning Year 2000 compliance status from a group of critical suppliers and vendors. This information has assisted the Company in determining the extent to which it may be vulnerable to the failure of third parties to address their Year 2000 compliance issues. Based on the responses received to date, the Company believes that its critical suppliers and vendors will be Year 2000 compliant.

Management believes it has a program to address the Year 2000 compliance issue in a timely manner. Final completion of the plan and testing of replacement or modified systems is anticipated by November 30, 1999. Nevertheless, since it is not possible to anticipate all possible future outcomes, especially when third parties are involved, there could be circumstances in which the Company would be unable to invoice customers or collect payments. The failure to correct a material Year 2000 compliance problem could result in an interruption in or failure of certain normal business activities or operations of the Company. Such failures could have a material adverse effect on the Company. The amount of potential liability and lost revenue has not been estimated.

The Company and EPCO have developed a contingency plan to address unavoidable risks associated with Year 2000 compliance issues. Management has examined the Year 2000 compliance issue and determined that a worst-case scenario would be a total, unexpected facility shutdown caused by a disruption of third-party utilities (principally a total electrical power outage). Enterprise personnel are trained to respond timely and effectively to such emergencies; however, because of the uncertainty surrounding the Year 2000 problem, the Company will have additional resources available to assist the operations, maintenance, and various other groups on December 31, 1999 and January 1, 2000. The Company will have extra operating, maintenance, process control, computer support, environmental and safety personnel on site and/or on standby in the event that a Year 2000 problem arises. The Company and EPCO will have a defined team of trained personnel available for the rollover into January 1, 2000, so that any disruption to Company or EPCO facilities can be handled safely and so that a return to normal operations can be commenced as soon as is practicable.

Accounting Standards

On June 6, 1999, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities-Deferral of the Effective Date of FASB Statement No. 133-an amendment of FASB Statement No. 133" which effectively delays and amends the application of SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" for one year, to fiscal years beginning after June 15, 2000. Management is currently studying both SFAS No. 137 and SFAS No. 133 for possible impact on the consolidated financial statements.

On April 3, 1998, the American Institute of Certified Public Accountants issued Statement of Position ("SOP") 98-5, "Reporting on the Costs of Start-Up Activities." For years beginning after December 15, 1998, SOP 98-5 generally requires that all start-up costs of a business activity be charged to expense as incurred and any start-up costs previously deferred should be written off as a cumulative effect of a change in accounting principle. Adoption of SOP 98-5 during 1999 did not have a material impact on the consolidated financial statements except for a $4.5 million noncash write-off that occurred on January 1, 1999 of the unamortized balance of deferred start-up costs of BEF, in which the Company owns a 33-1/3% interest. This write-off caused a $1.5 million reduction in the equity in income of unconsolidated affiliates for 1999 and a corresponding reduction in the Company's investment in unconsolidated affiliates.

Uncertainty of Forward-Looking Statements and Information.

This quarterly report 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," and "may," and similar expressions and statements regarding the plans and objectives of the Company for future operations, are intended to identify forward-looking statements. Although the Company and the General Partner believe that the expectations reflected in such forward-looking statements are reasonable, they can give no assurance that such expectations will prove to be correct. Such statements are subject to certain risks, uncertainties, and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual results may vary materially from those anticipated, estimated, projected, or expected. Among the key risk factors that may have a direct bearing on the Company's results of operations and financial condition are: (a) competitive practices in the industries in which the Company competes, (b) fluctuations in oil, natural gas, and NGL product prices and production, (c) operational and systems risks, (d) environmental liabilities that are not covered by indemnity or insurance, (e) the impact of current and future laws and governmental regulations (including environmental regulations) affecting the NGL industry in general, and the Company's operations in particular, (f) loss of a significant customer, and (g) failure to complete one or more new projects on time or within budget.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Historically, the Company has been exposed to financial market risks, including changes in interest rates with respect to its investments in financial instruments and changes in commodity prices. The Company could, but generally did not, use derivative financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) or derivative commodity instruments (i.e., commodity futures, forwards, swaps, or options, and other commodity instruments with similar characteristics that are permitted by contract or business custom to be settled in cash or with another financial instrument) to mitigate either of these risks. The return on the Company's financial investments was generally not affected by foreign currency fluctuations. Through the third quarter of 1999, the Company did not use any material derivative financial instruments for speculative purposes. At September 30, 1999, the Company had no material derivative instruments in place to cover any potential interest rate, foreign currency or other financial instrument risk.

At September 30, 1999, the Company had $21.6 million invested in cash and cash equivalents. 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. The Company's inventory of NGLs and NGL products at September 30, 1999, was $103.0 million. Inventories are carried at the lower of cost or market. A 10% adverse change in commodity prices would result in an approximate $10.3 million decrease in the fair value of the Company's inventory, based on a sensitivity analysis at September 30, 1999. Actual results may differ materially. All the Company's long-term debt is at variable interest rates; a 10% change in the base rate selected would have an approximate $2.1 million effect on the amount of interest expense for the year based upon amounts outstanding at September 30, 1999.

Beginning with the fourth quarter of 1999, the Company adopted a commercial policy to manage exposures to the risks generated by the NGL business. The objective of the 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 Board of Directors of the general partner. The Company will enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to energy commodities on both a short-term (less than 30 days) and long-term basis, not to exceed 18 months. The general partner has established a Risk Committee (the "committee") that will oversee overall strategies associated with physical and financial risks. The committee will approve specific commercial policies of the Company subject to this policy, including authorized products, instruments and markets. The committee is also charged with establishing specific guidelines and procedures for implementing the policy and ensuring compliance with the policy. This policy will affect transactions beginning with the fourth quarter of 1999.

PART II. OTHER INFORMATION

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

*3.1 Form of Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. (Exhibit 3.1 to Registration Statement on Form S-1, File No. 333-52537, filed on May 13, 1998).

*3.2 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).

*3.3 LLC Agreement of Enterprise Products GP (Exhibit 3.3 to Registration Statement on Form S-1/A, File No. 333-52537, filed on July 21, 1998).

*3.4 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 in the Schedule 13D filed September 27, 1999 by Tejas Energy LLC ; filed as Exhibit 99.7 on Form 8-K dated October 4, 1999).

*3.5 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).

*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 $200 million Credit Agreement among Enterprise Products Operating L.P., the Several Banks from Time to Time Parties Hereto, Den Norske Bank ASA, and Bank of Tokyo-Mitsubishi, Ltd., Houston Agency as Co-Arrangers, The Bank of Nova Scotia, as Co-Arranger and as Documentation Agent and The Chase Manhattan Bank as Co-Arranger and as Agent dated as of July 27, 1998 as Amended and Restated as of September 30, 1998. (Exhibit 4.2 on Form 10-K for year ended December 31, 1998, filed March 17, 1999).

*4.3 First Amendment to $200 million Credit Agreement dated July 28, 1999 among Enterprise Products Operating L.P. and the several banks thereto. (Exhibit 99.9 on Form 8-K/A-1 filed October 27, 1999).

*4.4 $350 million Credit Agreement among Enterprise Products Operating L.P., BankBoston, N.A., Societe Generale, Southwest Agency and First Union National Bank, as Co-Arrangers, The Chase Manhattan Bank, as Co-Arranger and as Administrative Agent, The First National Bank of Chicago, as Co-Arranger and as Documentation Agent, The Bank of Nova Scotia, as Co-Arranger and Syndication Agent, and the Several Banks from Time to Time parties hereto with First Union Capital Markets acting as Managing Agent and Chase Securities Inc. acting as Lead Arranger and Book Manager dated July 28, 1999 (Exhibit 99.10 on Form 8-K/A-1 filed October 27, 1999).

*4.5 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 in the Schedule 13D filed September 27, 1999 by Tejas Energy LLC ; filed as Exhibit 99.5 on Form 8-K dated October 4, 1999).

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

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

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

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

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

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

*10.7 Articles of Partnership of Mont Belvieu Associates dated July 17, 1985 (Exhibit 10.7 to Registration Statement on Form S-1, File No. 333-52537, filed on May 13, 1998).

*10.8 First Amendment to Articles of Partnership of Mont Belvieu Associates dated July 15, 1996 (Exhibit 10.8 to Registration Statement on Form S-1, File No. 333-52537, filed on May 13, 1998).

*10.9 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).

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

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

*10.12 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).

*10.13 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).

10.14Fourth Amendment to Conveyance of Gas Processing Rights between Tejas Natural Gas Liquids, LLC and Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Deepwater Development Inc., Shell Land & Energy Company and Shell Frontier Oil & Gas Inc. dated August 1, 1999.

*99.1Contribution Agreement between Tejas Energy LLC, Tejas Midstream Enterprises, LLC, Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products Company, Enterprise Products GP, LLC and EPC Partners II, Inc. dated September 17, 1999. (The Company incorporates by reference the above document included in the Schedule 13D filed September 27, 1999 by Tejas Energy LLC ; filed as Exhibit 99.4 on Form 8-K dated October 4, 1999).

*99.2Registration 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 in the Schedule 13D filed September 27, 1999 by Tejas Energy LLC ; filed as Exhibit 99.6 on Form 8-K dated October 4, 1999).

27.1 Financial Data Schedule

* Asterisk indicates exhibits incorporated by reference as indicated

(b) Reports on Form 8-K

Three reports on Form 8-K were filed during the third quarter of 1999 associated with the Tejas acquisition.

On September 20, 1999 a Form 8-K was filed whereby the Company announced it had completed its acquisition of TNGL, from Tejas Energy, an affiliate of Shell. In exchange for its NGL business, Tejas Energy received 14.5 million convertible special partnership units in the Company and $166 million in cash. Tejas Energy has the opportunity to earn an additional 6.0 million convertible contingency units over the next two years. As part of the transaction, the Company has entered into a long-term gas processing agreement with Shell for its Gulf of Mexico production. TNGL's NGL businesses include natural gas processing and NGL fractionation, transportation, storage and marketing. All of TNGL's assets in Louisiana and Mississippi are included under the terms of the transaction. This acquisition by the Company forms a fully integrated Gulf Coast NGL processing, fractionation, storage, transportation and marketing business.

On October 4, 1999, a Form 8-K was filed whereby the Company summarized the Unitholder Rights Agreement and other material agreements associated with the TNGL acquisition. This filing incorporated by reference certain material documents associated with the acquisition.

On October 27, 1999, a Form 8-K/A-1 was filed whereby the Company disclosed certain historical financial information of TNGL for the years ended 1996, 1997, and 1998. In addition, this filing contained other documentation relating to the TNGL acquisition.

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

Date: November 15, 1999

By: /s/ Gary L. Miller
Executive Vice President
Chief Financial Officer and Treasurer

THIS SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM COMBINED FINANCIAL STATEMENTS AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS.

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FOURTH AMENDMENT TO CONVEYANCE
OF GAS PROCESSING RIGHTS

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FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS

THIS FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS (this "Agreement") dated as of August 1, 1999 is made by and between Tejas Natural Gas Liquids, LLC ("Processor"), a Delaware limited liability company, on the one hand, and Shell Oil Company ("SOC"), Shell Exploration & Production Company ("SEPCO"), Shell Offshore Inc. ("SOI"), Shell Deepwater Development Inc. ("SDDI"), Shell Deepwater Production Inc. ("SDPI"), Shell Consolidated Energy Resources Inc. ("SCERI"), Shell Land & Energy Company ("SLEC"), and Shell Frontier Oil & 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 E&P 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 September 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. The parties desire to further amend the Third Amendment to clarify 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 degrees 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 degrees F and either the equilibrium pressure of the product at 60 degrees 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 other generally accepted natural gas processing methods.

1.27 "Processor" means Tejas Natural Gas Liquids, LLC 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 E, 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 the date of this Agreement 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 with notice of the estimated quantity of New Volumes and the estimated date on which such New Volumes will be available for Processing as soon as reasonably practicable. 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, 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 (said Exhibit A to be provided by Producers within 30 days of Producers' execution of this Agreement and verified by Processor within 90 days of receipt of said Exhibit A from Producers). 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 day's 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. 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 Produce'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 . 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 for such Producer's Equity Gas Processed at such 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, at the beginning of each calendar month, the Consideration Basis shall be the respective adjusted index price listed by Plant and Upstream Pipeline, as applicable, on Exhibit C (Inside FERC) for all Producers' Equity Gas processed; provided, however, Processor may elect to change the Consideration Basis from the adjusted index price listed on Exhibit C to the respective adjusted index price listed on Exhibit D (Gas Daily) for all Producers' Equity Gas processed. Processor shall provide notice of such election to Producers no later than 3:00 p.m. Houston, Texas time on the last business day of the month preceeding the month during which such election is to be effective. If Processor elects to change the Consideration Basis from Exhibit C to Exhibit D, the Consideration Basis shall be the arithmetic average of the daily postings for all days of the month for the applicable indices (the preceeding Friday's posting will be used for the following Saturdays and Sundays in such calculation).

6.3 Consideration Timing. Processor shall pay Producer the applicable consideration set forth in Section 6.1 no later than 60 days following the last day of the month in which subject PTR and Processor's Retrograde is delivered to a Plant.

6.4 Consideration Basis Updates. Processor and Producers shall periodically amend Exhibits C and D, as appropriate, if (i) another Plant is added by Processor, (ii) the price indexes listed in Exhibits C or D are no longer available or (iii) different index prices would, in the reasonable judgment of Processor and Producers, more accurately represent market conditions. Any new Consideration Basis shall represent either (i) the price of Gas at the Field Delivery Point of the Upstream Pipeline that is connected to a respective Plant, multiplied by 1.05 or (ii) the price of the Gas at another mutually agreeable location, whichever more closely represents the value of the Gas at the Plant Redelivery Point.

6.5 Processor Provided PTR. Producers acknowledge that Processor currently is and may from time to time be required to provide PTR at a particular Plant for Producer's Equity Gas Processed at such Plant for Processor's own account (for example, aggregation of PTR for Plant owners and third parties who process Gas at the Calumet Plant on Trunkline pipeline). Producers agree that Processor has the right to provide PTR for Producer's Equity Gas Processed at such Plant(s) for Processor's own account as may be required from time to time. Processor agrees to initiate any such change from Producers providing PTR to Processor providing PTR on the first day of a month and to provide Producers with at least ten days notice of any such change. During any period of time that Processor provides PTR for its own account as allowed under this Section 6.5, no consideration under Section 6.1 is due to the Producers for any such PTR provided by Processor.

7. PTR AND PTR TRANSPORTATION

Producers, at their sole expense, 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. 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. As between Processor and Producers, the obligation to pay royalty due on Equity Gas production and Processor's Retrograde, including but not limited to the Products recovered through Processing, shall be divided as follows:

(a) Producers shall remain fully liable to remit payment to the Department of the Interior, the Minerals Management Service, the States of Louisiana, Texas, Mississippi, Alabama and Florida, and any private lessors who are not federal or state lessors, for any royalty and severance taxes due on all hydrocarbon production; and

(b) Processor shall fully reimburse Producers for any royalty payments required by the Department of the Interior, the Minerals Management Service, the States of Louisiana, Texas, Mississippi, Alabama and Florida, and any private lessors who are not federal or state lessors, on any Incremental Value (as defined hereafter) associated with Processing the Equity Gas and Processor's Retrograde. "Incremental Value" is defined as the value of the NGL Products extracted from the Equity Gas and Processor's Retrograde less (i) the value of the PTR as a Gas and (ii) any other expenses or allowances associated with Processing that are allowed as deductions for royalty purposes under a Lease. Prices used to determine the value of the NGL Products and PTR shall be those that are recognized by the respective lessor. Processor will tender such monthly payments of cash on or before 60 days following the calendar month in which Equity Gas was delivered to the Plant Delivery Point for Processing.

(c) Producers and Processor agree to work together to establish a process to ensure that all information required for the calculation of royalty payments to be made under the terms of this Section 8 is exchanged in a timely manner.

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 this Section 16, 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 award rendered may be entered in any court having jurisdiction thereof; and any such party may institute proceedings in any court having jurisdiction for the specific performance by any party of any such award. Each of the parties specifically agrees to be bound by any 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 the determination of the arbitrators.

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 17.5, 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. Producers further agree to make any transfer of any Dedicated Lease subject to the terms and conditions of this Agreement and not to transfer Producer's interest in a Dedicated Lease without first requiring the transferee to execute and deliver to Producer and Processor Letter of Attornment in the form attached as Exhibit F.

17.3 Affiliates of Producer Parties. Subject to Section 17.5, 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]	Processor:	Tejas Natural Gas Liquids, LLC
	c/o Shell Offshore, Inc.		1301 McKinney Street, Ste. 700
	200 N. Dairy Ashford		Houston, TX 77010
	Houston, TX 77079		Fax #: (713) 230-1730
	Fax #: (281) 544-3544		Attn: Vice President-NGL Assets
	Attn: Team Leader Marketing & Transportation		

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.

PRODUCERS:

SHELL OIL COMPANY	WITNESSES:
By: /s/ B.K. Garrison	/s/ Cindy Bustillo
Name: B.K. Garrison	
Title: Attorney-in-Fact	/s/ illegible signature

SHELL OFFSHORE INC. WITNESSES:

By: /s/ J.W. Kimmel /s/ Cindy Bustillo
Name: J.W. Kimmel
Title: Attorney-in-Fact /s/ illegible signature

SHELL DEEPWATER PRODUCTION INC. WITNESSES:

By: /s/ J.W. Kimmel /s/ Cindy Bustillo
Name: J.W. Kimmel
Title: Attorney-in-Fact /s/ illegible signature

SHELL DEEPWATER DEWITNESSES:
INC.

By: /s/ J.W. Kimmel /s/ Cindy Bustillo
Name: J.W. Kimmel
Title: Attorney-in-Fact /s/ illegible signature

SHELL CONSOLIDATED ENERGY WITNESSES:
RESOURCES INC.

By: /s/ B.K. Garrison /s/ Cindy Bustillo
Name: B.K. Garrison
Title: Attorney-in-Fact /s/ illegible signature

SHELL LAND & ENERGWITNESSES:

By: /s/ B.K. Garrison /s/ Cindy Bustillo
Name: B.K. Garrison
Title: Attorney-in-Fact /s/ illegible signature

SHELL FRONTIER OIL & GAS INC. WITNESSES:

By: /s/ B.K. Garrison /s/ Cindy Bustillo
Name: B.K. Garrison
Title: Attorney-in-Fact /s/ illegible signature

SHELL EXPLORATION & WITNESSES:
PRODUCTION COMPANY

By: /s/ Walter van de Vijver /s/ illegible signature
Name: Walter van de Vijver
Title: President & CEO /s/ illegible signature

PROCESSOR:

TEJAS NATURAL WITNESSES:S, LLC

By: /s/ A.J. Teague /s/ illegible signature
Name: A. J. Teague
Title: President /s/ illegible signature

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared B.K. Garrison, known to me to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as Agent and Attorney-in-Fact for Shell Oil Company, a Delaware corporation, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this ____ day of _________, 1999.

/s/ Cindy Bustillo
Notary Public

My Commission Expires:_______________.

[NOTARY STAMP]

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared J.W. Kimmel, known to me to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as Agent and Attorney-in-Fact for Shell Offshore Inc., a Delaware corporation, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this _____ day of ________, 1999.

/s/ Cindy Bustillo
Notary Public

My Commission Expires_______________.

[NOTARY STAMP]

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared J.W. Kimmel, be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as Agent and Attorney-in-Fact for Shell Deepwater Production Inc., a Delaware corporation, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this ____ day of ________, 1999.

/s/ Cindy Bustillo
Notary Public

My Commission Expires_______________.

[NOTARY STAMP]

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared J.W. Kimmel, known to me to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as Agent and Attorney-in-Fact for Shell Deepwater Development Inc., a Delaware corporation, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this ___ day of ________, 1999.

/s/ Cindy Bustillo
Notary Public

My Commission Expires_______________.

[NOTARY STAMP]

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared B.K. Garrison, known to me to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as Agent and Attorney-in-Fact for Shell Consolidated Energy Resources Inc., a Delaware corporation, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this _______ day of __________, 1999.

/s/ Cindy Bustillo
Notary Public

My Commission Expires_______________.

[NOTARY STAMP]

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared B.K. Garrison, known to me to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as Agent and Attorney-in-Fact for Shell Land & Energy Company, a Delaware corporation, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this _______ day of ___________, 1999.

/s/ Cindy Bustillo
Notary Public

My Commission Expires_______________.

[NOTARY STAMP]

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared B.K. Garrison, known to me to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as Agent and Attorney-in-Fact for Shell Frontier Oil & Gas Inc., a Delaware corporation, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this _______ day of ___________, 1999.

/s/ Cindy Bustillo
Notary Public

My Commission Expires_______________.

[NOTARY STAMP]

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared Walter van de Vijver, known to me to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as President & CEO for Shell Exploration & Production Company, a Delaware corporation, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this _____ day of ____________, 1999.

/s/ Kathryn W. Coleman
Notary Public

My Commission Expires_______________.

[NOTARY STAMP]

STATE OF TEXAS
COUNTY OF HARRIS

BEFORE ME, the undersigned Notary Public, on this day personally appeared A. J. Teague, known to me to be the person whose name is subscribed to the foregoing instrument and acknowledged to me that he, being fully authorized to do so, executed and delivered the same as Agent and President for Tejas Natural Gas Liquids, LLC, a Delaware limited liability company, on the day and year therein mentioned and as the act and deed of said corporation, for the purpose and consideration therein expressed.

GIVEN UNDER MY HAND AND SEAL OF OFFICE, this _______ day of ____________, 1999.

/s/ Phebia E. Watts
Notary Public

My Commission Expires_______________.

[NOTARY STAMP]

EXHIBIT A

FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS
DEDICATED LEASES AS OF AUGUST 1, 1999

(to be provided by Producers under the terms of Section 3.2 of this Agreement)

EXHIBIT B

FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS
EXCLUDED LEASES

SUPPLY SOURCE	RECEIPT POINT	RELATED PLANT / OPERATOR	RELATED PIPELINE
Grand Isle 33	Grand Isle 33	Grand Isle / Exxon	Exxon's Grand Isle Gathering System

FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS
CONSIDERATION BASES

PLANT	CONSIDERATION BASIS
Barracuda	GMR - Transcontinental Gas Pipeline Corp., Zone 2 (pooling point)
Blue Water	Average of GMR - Tennessee Gas Pipeline, La. & Offshore (zone 1) x 1.05 GMR - Columbia Gulf Transmission Co., Louisiana
Burns Point	GMR - Koch Gateway Pipeline Co., South Louisiana/East Side x 1.05
Calumet	
- - ANR	GMR - ANR Pipeline Co., Louisiana x 1.05
- - Trunkline	GMR - Trunkline Gas Co., Louisiana x 1.05
Garden City/Neptune	Average of GMR - Koch Gateway Pipeline Co., South Louisiana/East Side GMR - Columbia Gulf Transmission Co., Louisiana GMR - Texas Gas Transmission Corp., Zone SL GMR - Henry Hub
Iowa	GMR - Texas Eastern Transmission Corp., West Louisiana zone x 1.05
N.Terrebonne	GMR - Transcontinental Gas Pipeline Corp., Zone 3 (pooling point)
Mobile Bay* (Yellowhammer only)	Average of GMR - Transcontinental Gas Pipe Line Corp., Mississippi, Alabama less 9.6 cents GMR - Florida Gas Transmission Co., Zone 3

Note: GMR ==> Inside F.E.R.C.'s Gas Market Report, First of Month Index

* Assumes Processor or Processor's agent pays any cost associated with moving all of the Yellowhammer Gas to the Plant.

FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS
CONSIDERATION BASES

PLANT	CONSIDERATION BASIS
Pascagoula	Average of GMR - Transcontinental Gas Pipe Line Corp., Mississippi, Alabama GMR - Koch Gateway Pipeline Co., South Louisiana/East Side GMR - Florida Gas Transmission Co., Zone 3 GMR - Southern Natural Gas, Louisiana GMR - Tennessee Gas Pipeline, La. & Offshore (zone 1)
Sabine Pass	GMR - Tennessee Gas Pipeline, La. & Offshore (zone 1) x 1.05
Sea Robin	Average of GMR - Columbia Gulf Transmission Co., Louisiana GMR - Southern Natural Gas Co., Louisiana
Stingray	GMR - Natural Gas Pipeline Co. of America, Louisiana
Toca	GMR - Southern Natural Gas, Louisiana x 1.05
Venice	Average of GMR - Texas Eastern Transmission Corp., East Louisiana zone GMR - Columbia Gulf Transmission Co., Louisiana GMR - Koch Gateway Pipeline Co., South Louisiana/East Side
Yscloskey	GMR - Tennessee Gas Pipeline, La. & Offshore (zone 1) x 1.05

Note: GMR ==> Inside F.E.R.C.'s Gas Market Report, First of Month Index

FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS
CONSIDERATION BASES

PLANT	CONSIDERATION BASIS
Barracuda	GDLM - Transco, St.45
Blue Water	Average of GDLM - Tennessee, 800 Leg X 1.05 GDLM - Columbia
Burns Point	GDLM - Koch (Zones 2&4) X 1.05
Calumet	
- - ANR	GDLM - ANR X 1.05
- -Trunkline	GDLM - Trunkline ELA X 1.05
Garden City/Neptune	Average of GDLM - Koch (Zones 2&4) GDLM - Columbia GDLM - Texas Gas SL GDLM - Henry Hub
Iowa	GDLM - Texas E. (WLA) X 1.05
N. Terrebonne	GDLM - Transco, St.65
Mobile Bay* (Yellowhammer only)	Average of GDMAM - Transco, St 85 less 9.6 cents GDLM - FGT Z3

GDLM = Gas Daily; Louisiana-Onshore South; Midpoint
GDMAM = Gas Daily; Mississippi-Alabama; Midpoint

* Assumes Processor or Processor's agent pays any cost associated with moving all of the Yellowhammer Gas to the Plant.

FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS
CONSIDERATION BASES

PLANT	CONSIDERATION BASIS
Pascagoula	Average of GDMAM - Transco, St 85 GDLM - Koch (Zones 2&4) GDLM - FGT Z3 GDLM - Sonat GDLM - Tennessee, 500 Leg
Sabine Pass	GDLM - Tennessee, 800 Leg X 1.05
Sea Robin	Average of GDLM - Columbia GDLM - Sonat
Stingray	GDLM - NGPL (La.)
Toca	GDLM - Sonat X 1.05
Venice	Average of GDLM - Texas E. (ELA) GDLM - Columbia GDLM - Koch (Zones 2&4)
Yscloskey	GDLM - Tennessee, 500 Leg X 1.05

GDLM = Gas Daily; Louisiana-Onshore South; Midpoint
GDMAM = Gas Daily; Mississippi-Alabama; Midpoint

EXHIBIT E

FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS
UPSTREAM PIPELINES WITH PROCESSOR'S RETROGRADE

Upstream Pipeline	Gas Plant	County/Parish
Southern Natural Pipeline	Toca	St, Bernard, LA
Mississippi Canyon Gas Pipeline	Venice	Plaquemines, LA
Destin Pipeline	Pascagoula	Jackson, MS

EXHIBIT F

FOURTH AMENDMENT TO CONVEYANCE OF GAS PROCESSING RIGHTS
ATTORNMENT LETTER

[Name of Processor] [Name of Transferee of Lease]
[Address of Processor] [Address of Transferee of Lease]

Gentlemen:

Subject: Transfer of Certain Leases
Notification and Consent to Assignment

1. Agreement for Transfer of Leases. Per prior discussions, your respective offices have been apprised that [name of producer] ("[name of producer]") and [name of transferee] ("Successor Producer") have entered an agreement by which [name of producer] will transfer to Successor Producer (the "Transfer") those certain interests in and to certain properties and leases as described on Exhibits A & B (the "Properties").

2. Cognizance of Prior Conveyance of Processing Rights. The parties acknowledge that all gas processing rights associated with the Properties have been conveyed to Processor by virtue of that certain Fourth Amendment to Conveyance of Gas Processing Rights (the "Conveyance of Processing Rights") dated June 30, 1999 by and between Tejas Natural Gas Liquids, LLC ("Processor"), on the one hand, and Shell Oil Company and certain of its named affiliates (collectively, "Producers").

3. Reservation of Rights by Processor. Processor hereby expressly reserves all its rights under the Conveyance of Processing Rights with respect to the Properties. Successor Processor hereby acknowledges and agrees that it is acquiring the Properties subject to the rights conveyed to Processor in the Conveyance of Processing Rights.

4. Assumption of Producer's Obligations. Successor Producer hereby assumes and agrees to perform all of the obligations of [name of producer] to Processor, and receives and accepts all rights of [name of producer], under the Conveyance of Processing Rights, insofar as they relate to the Properties.

5. Consent to Transfer. Processor hereby acknowledges and consents to the Transfer and agrees to render to Successor Producer the performance of Processor's obligations to Producers under the Conveyance of Processing Rights insofar as they relate to the Properties.

6. Counterparts. This document may be executed in any number of counterparts, each of which when combined and taken together, shall be considered but one and the same document.

7. Covenants Running with the Land. The parties intend that, to the extent permitted by law, this instrument and the Conveyance of Gas Processing Rights shall be considered to be covenants running with the Properties which shall inure to the benefit of, and be binding upon, the successors and assigns of the parties' interests insofar as they relate to the Conveyance of Gas Processing Rights or the Properties.

Your prompt attention to this matter will be appreciated. Should you have any questions or require further information in this regard, please contact our office.

Yours very truly,

Name
[title]
[NAME OF TRANSFEREE]

Agreed to and approved this ______ day of

______________________, 1999.

By: ___________________________

Title: _________________________

[NAME OF PRODUCER]

Agreed to and approved this ______ day of

_____________________, 1999.

By:

Title:

TEJAS NATURAL GAS LIQUIDS, LLC

Agreed to and approved this ______ day of

_____________________, 1999.

By:

Title: