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

Form 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2003

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 No. 1-11680

GulfTerra Energy Partners, L.P.

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0396023** (I.R.S. Employer Identification No.)
4 Greenway Plaza **Houston, Texas** (Address of Principal Executive Offices)	**77046** (Zip Code)

Registrant's Telephone Number, Including Area Code: **(832) 676-4853**

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 ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

The registrant had 58,361,149 common units outstanding as of October 29, 2003.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)
(Unaudited)

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
Operating revenues	$283,666	$122,249	$872,701	$304,282
Operating expenses				
Cost of natural gas and other products	134,112	27,767	432,159	67,268
Operation and maintenance	51,221	32,838	140,416	76,531
Depreciation, depletion and amortization	25,218	19,274	73,761	49,939
(Gain) loss on sale of long-lived assets	(18,964)	434	(18,707)	119
	191,587	80,313	627,629	193,857
Operating income	92,079	41,936	245,072	110,425
Other income (loss)				
Earnings from unconsolidated affiliates	3,195	3,168	9,498	10,541
Minority interest expense	(889)	(8)	(969)	(13)
Other income	250	320	942	1,181
Interest and debt expense	33,197	22,070	99,521	55,362
Loss due to write-off of debt issuance costs	1,225	—	4,987	—
Income from continuing operations	60,213	23,346	150,035	66,772
Income from discontinued operations	—	456	—	4,901
Cumulative effect of accounting change	—	—	1,690	—
Net income	$ 60,213	$ 23,802	$151,725	$ 71,673
Income allocation				
Series B unitholders	$ 4,018	$ 3,693	$ 11,792	$ 10,875
General partner				
Continuing operations	$ 18,031	$ 10,755	$ 48,747	$ 30,245
Discontinued operations	—	5	—	49
Cumulative effect of accounting change	—	—	17	—
	$ 18,031	$ 10,760	$ 48,764	$ 30,294
Common unitholders				
Continuing operations	$ 31,337	$ 8,898	$ 72,951	$ 25,652
Discontinued operations	—	451	—	4,852
Cumulative effect of accounting change	—	—	1,340	—
	$ 31,337	$ 9,349	$ 74,291	$ 30,504
Series C unitholders				
Continuing operations	$ 6,827	$ —	$ 16,545	$ —
Cumulative effect of accounting change	—	—	333	—
	$ 6,827	$ —	$ 16,878	$ —
Basic earnings per common unit				
Income from continuing operations	$ 0.63	$ 0.20	$ 1.54	$ 0.61
Income from discontinued operations	—	0.01	—	0.11
Cumulative effect of accounting change	—	—	0.03	—
Net income	$ 0.63	$ 0.21	$ 1.57	$ 0.72
Diluted earnings per common unit				
Income from continuing operations	$ 0.62	$ 0.20	$ 1.53	$ 0.61
Income from discontinued operations	—	0.01	—	0.11
Cumulative effect of accounting change	—	—	0.03	—
Net income	$ 0.62	$ 0.21	$ 1.56	$ 0.72
Basic weighted average number of common units outstanding	50,072	44,130	47,388	42,373
Diluted weighted average number of common units outstanding	50,385	44,130	47,653	42,373
Distributions declared per common unit	$ 0.70	$ 0.65	$ 2.05	$ 1.93

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except unit amounts)
(Unaudited)

	September 30, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 58,944	$ 36,099
Accounts receivable, net	174,781	223,345
Affiliated note receivable	22,051	17,100
Other current assets	19,972	3,451
Total current assets	275,748	279,995
Property, plant, and equipment, net	2,800,089	2,724,938
Intangible assets	3,426	3,970
Investment in unconsolidated affiliates	157,375	78,851
Other noncurrent assets	45,131	43,142
Total assets	$3,281,769	$3,130,896
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable	$ 151,226	$ 212,868
Accrued interest	42,341	15,028
Current maturities of senior secured term loan	5,000	5,000
Other current liabilities	17,923	21,195
Total current liabilities	216,490	254,091
Revolving credit facility	328,000	491,000
Senior secured term loans, less current maturities	152,500	552,500
Long-term debt	1,405,271	857,786
Other noncurrent liabilities	30,148	23,725
Total liabilities	2,132,409	2,179,102
Minority interest	2,465	1,942
Partners' capital		
Limited partners		
Series B preference units; 123,865 and 125,392 units issued and outstanding	167,385	157,584
Common units; 50,533,649 and 44,030,314 units issued and outstanding	626,920	437,773
Series C units; 10,937,500 units issued and outstanding	345,194	351,507
General partner	10,367	8,610
Accumulated other comprehensive loss	(2,971)	(5,622)
Total partners' capital	1,146,895	949,852
Total liabilities and partners' capital	$3,281,769	$3,130,896

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Cash flows from operating activities		
Net income	$ 151,725	$ 71,673
Less cumulative effect of accounting change	1,690	—
Less income from discontinued operations	—	4,901
Income from continuing operations	150,035	66,772
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	73,761	49,939
Distributed earnings of unconsolidated affiliates		
Earnings from unconsolidated affiliates	(9,498)	(10,541)
Distributions from unconsolidated affiliates	11,390	13,140
(Gain) loss on sale of long-lived assets	(18,707)	119
Write-off of debt issuance costs	4,987	—
Other noncash items	1,973	1,193
Working capital changes, net of effects of acquisitions and noncash transactions	(4,586)	12,914
Net cash provided by continuing operations	209,355	133,536
Net cash provided by discontinued operations	—	5,007
Net cash provided by operating activities	209,355	138,543
Cash flows from investing activities		
Additions to property, plant and equipment	(246,295)	(146,544)
Proceeds from sale and retirement of assets	77,448	5,460
Additions to investments in unconsolidated affiliates	(33,879)	(30,364)
Proceeds from sale of equity investments	1,342	—
Cash paid for acquisitions, net of cash acquired	—	(741,416)
Net cash used in investing activities of continuing operations	(201,384)	(912,864)
Net cash provided by investing activities of discontinued operations	—	186,477
Net cash used in investing activities	(201,384)	(726,387)
Cash flows from financing activities		
Net proceeds from revolving credit facility	298,000	278,731
Repayments of revolving credit facility	(461,000)	(10,000)
Repayment of senior secured acquisition term loan	(237,500)	—
Net proceeds from GulfTerra Holding term loan	—	530,529
Repayment of GulfTerra Holding term loan	(160,000)	—
Repayment of senior secured term loan	(2,500)	(375,000)
Repayment of Argo term loan	—	(95,000)
Distributions to minority interests	(642)	—
Net proceeds from issuance of long-term debt	537,537	229,576
Net proceeds from issuance of common units and Series F convertible units	208,949	150,397
Distributions to partners	(167,974)	(112,752)
Contribution from General Partner	4	560
Net cash provided by financing activities of continuing operations	14,874	597,041
Net cash used in financing activities of discontinued operations	—	(3)
Net cash provided by financing activities	14,874	597,038
Increase in cash and cash equivalents	22,845	9,194
Cash and cash equivalents		
Beginning of period	36,099	13,084
End of period	$ 58,944	$ 22,278
Schedule of noncash investing and financing activities:		
Investment in Cameron Highway Oil Pipeline Company Joint Venture	$ 50,836	$ —
Redemption of Series B preference units contributed from our General Partner	$ 1,986	$ —

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(In thousands)
(Unaudited)

Comprehensive Income

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net income	$60,213	$23,802	$151,725	$ 71,673
Other comprehensive income (loss)	8,094	(565)	2,651	606
Total comprehensive income	$68,307	$23,237	$154,376	$ 72,279

Accumulated Other Comprehensive Income (Loss)

	September 30, 2003	December 31, 2002
Beginning balance	$(5,622)	$(1,272)
Unrealized mark-to-market losses on cash flow hedges arising during period	(5,150)	(6,428)
Reclassification adjustments for changes in value of derivative instruments to settlement date	8,136	1,579
Other comprehensive income (loss) from investment in unconsolidated affiliate	(335)	499
Ending balance	$(2,971)	$(5,622)
Accumulated other comprehensive loss allocated to:		
Common units' interest	$(2,170)	$(4,623)
Series C units' interest	$ (771)	$ (942)
General partner's interests	$ (30)	$ (57)

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. BASIS OF PRESENTATION

In May 2003, we changed our name to GulfTerra Energy Partners, L.P. from El Paso Energy Partners, L.P. and reorganized our general partner. In connection with our name change, we also changed the names of several subsidiaries in May 2003, including the following, as listed in the table below.

New Name	Former Name
GulfTerra Energy Finance Corporation	El Paso Energy Partners Finance Corporation
GulfTerra Arizona Gas, L.L.C.	El Paso Arizona Gas, L.L.C.
GulfTerra Intrastate, L.P.	El Paso Energy Intrastate, L.P.
GulfTerra Texas Pipeline, L.P.	EPGT Texas Pipeline, L.P.
GulfTerra Holding V, L.P.	EPN Holding Company, L.P.

Our sole general partner is GulfTerra Energy Company, L.L.C., a recently-formed Delaware limited liability company that is owned 90.1 percent by a subsidiary of El Paso Corporation and 9.9 percent by Goldman, Sachs & Co. (Goldman Sachs), a wholly owned subsidiary of Goldman Sachs Group Inc., a large publicly-traded investment banking company. El Paso Corporation (through its subsidiaries) owned 100 percent of our general partner until October 2003, when Goldman Sachs acquired its interest in our general partner.

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2002 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2003, and for the quarters and nine months ended September 30, 2003 and 2002, are unaudited. We derived the balance sheet as of December 31, 2002, from the audited balance sheet filed in our 2002 Annual Report on Form 10-K. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature, to fairly present our interim period results. Information for interim periods may not depict the results of operations for the entire year. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our previously reported net income or partners' capital. Also, starting with the quarter ended June 30, 2002, we have reflected the results of operations from our Prince assets disposition as discontinued operations.

Our accounting policies are consistent with those discussed in our 2002 Annual Report on Form 10-K, except as discussed below.

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts that we believe are uncollectible. We review collectibility regularly and adjust the allowance as necessary, primarily under the specific identification method. During 2003, we increased our allowance by $2.0 million. As of September 30, 2003 and December 31, 2002, our allowance was $4.5 million and $2.5 million.

As generally used in the energy industry and in this document, the following terms have the following meanings:

/d	= per day	Mcf	= thousand cubic feet
Bbl	= barrel	MDth	= thousand dekatherms
MBbls	= thousand barrels	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMBbls	= million barrels

When we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations*. The provisions of this statement relate primarily to our obligations to plug abandoned offshore wells that constitute part of our non-segment assets.

Upon our adoption of SFAS No. 143, we recorded (i) a $7.4 million net increase to property, plant, and equipment representing non-current retirement assets, (ii) a $5.7 million increase to noncurrent liabilities representing retirement obligations, and (iii) a $1.7 million increase to income as a cumulative effect of accounting change. Each retirement asset is depreciated over the remaining useful life of the long-term asset with which the retirement liability is associated. An ongoing expense is recognized for the interest component of the liability due to the changes in the value of the retirement liability as a result of the passage of time, which we reflect as a component of depreciation expense in our income statement.

Other than our obligations to plug and abandon wells, we cannot estimate the costs to retire or remove assets used in our business because we believe the assets do not have definite lives or we do not have the legal obligation to abandon or dismantle the assets. We believe that the lives of our assets or the underlying reserves associated with our assets cannot be estimated. Therefore, aside from the liability associated with the plugging and abandonment of offshore wells, we have not recorded liabilities relating to any of our other assets.

The pro forma income from continuing operations and amounts per unit for the quarter and nine months ended September 30, 2003 and 2002, assuming the provisions of SFAS No. 143 were adopted prior to the earliest period presented, are shown below:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands, except per unit amounts)			
Pro forma income from continuing operations	$ 60,213	$23,243	$150,035	$66,493
Pro forma income from continuing operations allocated to common unitholders	$ 31,337	$ 8,796	$ 72,951	$25,376
Pro forma basic income from continuing operations per weighted average common unit	$ 0.63	$ 0.20	$ 1.54	$ 0.60
Pro forma diluted income from continuing operations per weighted average common unit	$ 0.62	$ 0.20	$ 1.53	$ 0.60

The pro forma amount of our asset retirement obligations at September 30, 2003 and 2002 and at December 31, 2002, assuming asset retirement obligations as provided for in SFAS No. 143 were recorded prior to the earliest period presented are shown below:

Year	Liability Balance as of January 1	Accretion	Other Change in Liability	Liability Balance as of September 30	Liability Balance as of December 31
			(In thousands)		
2002	$5,277	$336	—	$5,613	$5,726
2003	$5,726	$340	$(246)[1]	$5,820	N/A

[1] Abandonment work performed during the quarter ended September 30, 2003.

Reporting Gains and Losses from the Early Extinguishment of Debt

In January 2003, we adopted SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* Accordingly, we now evaluate the nature of any debt extinguishments to determine whether to report any gain or loss resulting from the early extinguishment of debt as an extraordinary item or as income from continuing operations.

Accounting for Costs Associated with Exit or Disposal Activities

In January 2003, we adopted SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This statement impacts any exit or disposal activities that we initiate after January 1, 2003 and we now recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Our adoption of this pronouncement did not have an effect on our financial position or results of operations.

Accounting for Guarantees

In accordance with the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others,* we record a liability at fair value, or otherwise disclose, certain guarantees issued after December 31, 2002, that contractually require us to make payments to a guaranteed party based on the occurrence of certain events. We have not entered into any material guarantees that would require recognition under FIN No. 45.

Accounting for Derivative Instruments and Hedging Activities

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities.* This statement amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* to incorporate several interpretations of the Derivatives Implementation Group (DIG), and also makes several minor modifications to the definition of a derivative as it was defined in SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. There was no initial financial statement impact of adopting this standard, although the FASB and DIG continue to deliberate on the application of the standard to certain derivative contracts, which may impact our financial statements in the future.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.* This statement provides guidance on the classification of financial instruments, as equity, as liabilities, or as both liabilities and equity. The provisions of SFAS No. 150 are effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning July 1, 2003. We adopted the provisions of SFAS No. 150 on July 1, 2003, and our adoption had no material impact on our financial statements.

Accounting for Stock-Based Compensation

We use the intrinsic value method established in Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, to value unit options issued to individuals who are on our general partner's current board of directors and for those grants made prior to El Paso Corporation's acquisition of our general partner in August 1998 under our Omnibus Plan and Director Plan. For the quarters and nine months ending September 30, 2003 and 2002, the cost of this stock-based compensation had no impact on our net income, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. We use the provisions of SFAS No. 123 to account for all of our other stock-based compensation programs.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*. This statement amends SFAS No. 123, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the methods of accounting for stock-based employee compensation and the effect of the method used on reported results. This statement is effective for fiscal years ending after December 15, 2002. We have decided that we will continue to use APB No. 25 to value our stock-based compensation issued to individuals who are on our general partner's current board of directors and for those grants made prior to El Paso Corporation's acquisition of our general partner in August 1998 and will include data providing the pro forma income effect of using the fair value method as required by SFAS No. 148. We will continue to use the provisions of SFAS No. 123 to account for all of our other stock-based compensation programs.

If compensation expense related to these plans had been determined by applying the fair value method in SFAS No. 123, *Accounting for Stock-Based Compensation*, our net income allocated to common unitholders and net income per common unit would have approximated the pro forma amounts below:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands)			
Net income allocated to common unitholders, as reported	$31,337	$ 9,349	$74,291	$30,504
Add: Stock-based employee compensation expense included in reported net income	404	314	1,083	854
Less: Stock-based employee compensation expense determined under fair value based method	406	535	1,126	1,717
Pro forma net income allocated to common unitholders	$31,335	$ 9,128	$74,248	$29,641
Earnings per common unit:				
Basic, as reported	$ 0.63	$ 0.21	$ 1.57	$ 0.72
Basic, pro forma	$ 0.63	$ 0.21	$ 1.57	$ 0.70
Diluted, as reported	$ 0.62	$ 0.21	$ 1.56	$ 0.72
Diluted, pro forma	$ 0.62	$ 0.21	$ 1.56	$ 0.70

The effects of applying SFAS No. 123 in this pro forma disclosure may not be indicative of future amounts.

2. ACQUISITIONS AND DISPOSITIONS

San Juan Assets

During the quarter ended September 30, 2003, the total purchase price and net assets acquired for our November 2002 acquisition of the San Juan assets decreased $2.4 million due to post-closing purchase price adjustments related to natural gas imbalances, NGL in-kind reserves and well loss reserves. The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	At November 27, 2002
	(In Thousands)
Note receivable	$ 17,100
Property, plant and equipment	763,696
Intangible assets	470
Investment in unconsolidated affiliate	2,500
Total assets acquired	783,766
Imbalances payable	17,403
Other current liabilities	2,565
Total liabilities assumed	19,968
Net assets acquired	$763,798

EPN Holding Assets

During the nine months ended September 30, 2003, the total purchase price and net assets acquired for the April 2002 EPN Holding asset acquisition increased $17.5 million due to post-closing purchase price adjustments related primarily to natural gas imbalances assumed in the transaction. The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	At April 8, 2002
	(In thousands)
Current assets	$ 4,690
Property, plant and equipment	780,648
Intangible assets	3,500
Total assets acquired	788,838
Current liabilities	15,229
Environmental liabilities	21,136
Total liabilities assumed	36,365
Net assets acquired	$752,473

Exchange with El Paso Corporation

In connection with our November 2002 San Juan assets acquisition, El Paso Corporation retained the obligation to repurchase the Chaco Plant from us for $77 million in October 2021. As part of El Paso Corporation's sale of 9.9 percent of our general partner, we released El Paso Corporation from that obligation in exchange for El Paso Corporation contributing specified assets to us. The communication assets we received will be used in the operation of our pipeline systems. Prior to the October 2003 exchange, we had access to these assets under our general and administrative services agreement with El Paso Corporation. We recorded the received assets at El Paso Corporation's book value of $23.3 million with the offset to partners' capital.

As a result of the October 2003 exchange, we changed our accounting estimate of the depreciable life of the Chaco Plant, from 19 to 30 years in order to depreciate the Chaco Plant over its estimated useful life as compared to the original term of the repurchase agreement. Depreciation expense will decrease approximately $0.5 million and $2.3 million on a quarter and annual basis.

Cameron Highway Oil Pipeline Company

Refer to Note 10 for discussion related to our sale of a 50 percent interest in Cameron Highway Oil Pipeline.

3. PARTNERS' CAPITAL

Cash distributions

The following table reflects our per unit cash distributions to our common unitholders and the total distributions paid to our common unitholders, Series C unitholder and general partner during the nine months ended September 30, 2003:

Month paid	Common Unit	Common Unitholders	Series C Unitholder	General Partner
	(per unit)	(In millions)		
February	$0.675	$29.7	$7.4	$15.0
May	$0.675	$32.0	$7.4	$15.9
August	$0.700	$34.8	$7.7	$18.0

In October 2003 we declared a cash distribution of $0.71 per common unit and Series C unit, $49.2 million in aggregate, for the quarter ended September 30, 2003, which we will pay on November 14, 2003, to holders of record as of October 31, 2003. In addition, we will pay our general partner $21.2 million related to its general partner interest. At the current distribution rate, our general partner receives approximately 30.2 percent of the total cash distributions for its role as our general partner.

Public offering of common units

Since January 1, 2003, we have issued the following common units in public offerings:

Offering Date	Common Units Issued	Public Offering Price	Net Offering Proceeds
		(per unit)	(in millions)
October 2003	4,800,000	$40.60	$186.1
August 2003	507,228	$39.43	$ 19.7
June 2003	1,150,000	$36.50	$ 40.3
May 2003[(1)]	1,118,881	$35.75	$ 38.3
April 2003	3,450,000	$31.35	$103.1

(1) Offering includes 80 Series F convertible units offered. Refer to description below.

In addition to our public offerings of common units, in October 2003 we sold 3,000,000 common units privately to Goldman Sachs in connection with their purchase of a 9.9 percent membership interest in our general partner. We used the net proceeds of $111.5 million from that private sale to partially fund the redemption of all of our outstanding Series B preference units (see discussion below related to the redemption of the Series B preference units). We used the net proceeds of the remaining common unit offerings to temporarily reduce amounts outstanding under our revolving credit facility and for general partnership purposes.

In May 2003, we issued 1,118,881 common units and 80 Series F convertible units in a registered offering to a large institutional investor for approximately $38.3 million net of offering costs. Our Series F convertible units are not listed on any securities exchange or market. Each Series F convertible unit is comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that have identical terms except for vesting and termination dates and the number of underlying common units into which they may be converted. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until March 29, 2004 (subject to defined extension rights). The Series F2 units are convertible into up to $40 million of common units provided at least $40 million of Series F1 convertible units are converted prior to their termination. The Series F2 units terminate on March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75 or the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units; (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units, assuming we had received a conversion notice on September 30, 2003 and October 29, 2003, was $38.77 and $39.05. The Series F convertible units may be converted into a maximum of 8,329,679 common units. Holders of Series F convertible units are not entitled to vote or receive distributions. The value associated with the Series F convertible units is included in partners' capital as a component of common units capital.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26.00 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at September 30, 2003.

In connection with the offerings prior to October 2003, our general partner, in lieu of a cash contribution, contributed to us approximately $2.0 million of our Series B preference units in order to maintain its one percent general partner interest. We retired these preference units.

In October 2003, we redeemed all 123,865 of our remaining outstanding Series B preference units for $156 million, a 7 percent discount from their liquidation value of $167 million. For this redemption, we used the net proceeds of $111.5 million from our sale of 3,000,000 common units to Goldman Sachs, $44.1 million from cash on hand and from borrowings under our revolving credit facility. We reflected the discount as an increase to the common units capital, Series C units capital and to our general partner's capital accounts.

Other

Under our 1998 Omnibus Compensation Plan (Omnibus Plan), we granted, during the nine months ended September 30, 2003, 17,500 unit options, 25,000 time-vested restricted units and 25,000 performance-based restricted units to employees of El Paso Field Services, whose primary responsibilities are the commercial management of our assets. Additionally, we granted 5,226 restricted units and 10,500 unit options during the nine months ended September 30, 2003, to non-employee directors of our Board of Directors under our 1998 Common Unit Plan for Non-Employee Directors (formerly the 1998 Unit Option Plan for Non-Employee Directors). We have accounted for all of these unit options and restricted units, except for the unit options issued to non-employee directors, in accordance with SFAS No. 123. Under SFAS No. 123, we report the fair value of these issuances as deferred compensation. Deferred compensation is amortized to compensation expense over the respective vesting or performance period. We have accounted for the unit options issued to the non-employee directors of our general partner's Board of Directors in accordance with APB No. 25.

We estimate the fair value of each unit option issued under the Omnibus Plan during the nine months ended September 30, 2003, on the date of its grant using the Black-Scholes option-pricing model, with the following weighted average assumptions: dividend yield of 8.75%; expected volatility of 30.77%; a risk-free interest rate of 3.31%; and an expected life of eight years. We will amortize the fair value of the unit options over their two year vesting period.

We issued time-vested restricted units and the performance-based restricted units at fair value at their date of grant. The restrictions on the time-vested units will lapse in four years from the date of grant. The restrictions on the performance-based restricted units will lapse if we achieve a specified level of target performance for identified "greenfield" projects by June 1, 2007 (for the 15,000 performance-based restricted units issued in June 2003) and by August 1, 2007 (for the 10,000 performance-based restricted units issued in August 2003). If we do not reach those targets by the applicable dates, the performance-based units will be forfeited. We will amortize the fair value of the time-vested restricted units over their four-year restricted period and the fair value of the performance-based restricted units over their performance periods. The performance-based restricted units are not entitled to vote or to receive distributions, until after (and if) we achieve specified level of target performance. The restricted units issued to non-employee directors of our general partner's Board of Directors were issued at fair value at their date of grant. This fair value is being amortized to compensation expense over the period of service, which we have estimated to be one year.

Total unamortized deferred compensation as of September 30, 2003, was approximately $1.7 million. Deferred compensation is reflected as a reduction of partners' capital and is allocated 1 percent to our general partner and 99 percent to our limited partners. Total fair value of options, time-vested restricted units and performance based restricted units issued during the nine months ended September 30, 2003 under both the Omnibus Plan and the Director Plan was approximately $1.9 million.

Net proceeds from unit options exercised during the nine months ended September 30, 2003, was approximately $7.6 million.

4. EARNINGS PER COMMON UNIT

The following table sets forth the computation of basic and diluted earnings per common unit (in thousands (except for unit amounts)):

	Quarter Ended		Nine Months Ended	
	September 30, 2003	September 30, 2002	September 30, 2003	September 30, 2002
Numerator:				
Numerator for basic earnings per common unit —				
Income from continuing operations	$31,337	$ 8,898	$72,951	$25,652
Income from discontinued operations	—	451	—	4,852
Cumulative effect of accounting change	—	—	1,340	—
	$31,337	$ 9,349	$74,291	$30,504
Denominator:				
Denominator for basic earnings per common unit — weighted-average shares	50,072	44,130	47,388	42,373
Effect of dilutive securities:				
Unit options	270	—	139	—
Restricted units	14	—	11	—
Series F convertible units	29	—	115	—
Denominator for diluted earnings per common unit — adjusted for weighted-average common units	50,385	44,130	47,653	42,373
Basic earnings per common unit				
Income from continuing operations	$ 0.63	$ 0.20	$ 1.54	$ 0.61
Income from discontinued operations	—	0.01	—	0.11
Cumulative effect of accounting change	—	—	.03	—
	$ 0.63	$ 0.21	$ 1.57	$ 0.72
Diluted earnings per common unit				
Income from continuing operations	$ 0.62	$ 0.20	$ 1.53	$ 0.61
Income from discontinued operations	—	0.01	—	0.11
Cumulative effect of accounting change	—	—	.03	—
	$ 0.62	$ 0.21	$ 1.56	$ 0.72

5. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	September 30, 2003	December 31, 2002
	(In thousands)	
Property, plant and equipment, at cost[1]		
Pipelines	$2,338,600	$2,317,503
Platforms and facilities	121,105	120,962
Processing plant	305,904	308,517
Oil and natural gas properties	131,100	127,975
Storage facilities	336,296	331,562
Construction work-in-progress	302,195	177,964
	3,535,200	3,384,483
Less accumulated depreciation, depletion and amortization	735,111	659,545
Property, plant and equipment, net	$2,800,089	$2,724,938

(1) Includes leasehold acquisition costs with an unamortized balance of $3.4 million at September 30, 2003. One interpretation being considered relative to SFAS No. 141, *Business Combinations* and SFAS No. 142, *Goodwill and Intangible Assets* is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on our balance sheets. We will continue to include these costs in property, plant, and equipment until further guidance is provided.

6. FINANCING TRANSACTIONS

Credit Facilities

Revolving Credit Facility

In September 2003, we renewed our revolving credit facility to, among other things, expand the credit available from $600 million to $700 million and extend the maturity from May 2004 to September 2006.

Our credit facility consists of two parts: the revolving credit facility and a $160 million senior secured term loan maturing in 2007. Our credit facility is guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries, as detailed in Note 12, and our general partner, and are collateralized with substantially all of our assets (excluding the assets of our unrestricted subsidiaries) and our general partner's general and administrative services agreement. The interest rates we are charged on our credit facility is determined at our option using one of two indices that include (i) a variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) LIBOR. This interest rate we are charged is contingent upon our leverage ratio, as defined in our credit facility, and ratings we are assigned by S&P or Moody's. The interest we are charged would increase by 0.25% if the credit ratings on our senior secured credit facility decrease or our leverage ratio decreases, or, alternatively, would decrease by 0.25% if these ratings are increased or our leverage ratio improves. Additionally, we pay commitment fees on the unused portion of our revolving credit facility at rates that vary from 0.30% to 0.50%.

Our credit facility contains covenants that include restrictions on our and our subsidiaries' ability to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies and amend some of our contracts, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries and restrict our ability to make distributions to our unitholders.

At September 30, 2003, we had $328 million outstanding under our revolving credit facility at an average interest rate of 5.0% as determined using the variable base rate discussed above, increased by 0.50%. We decreased the average interest rate under this facility to 3.13% in October 2003 when we elected to convert the outstanding balances to LIBOR-based loans. The total amount available to us at September 30, 2003, under this facility was $208 million. At September 30, 2003, we had $157.5 million outstanding under our senior secured term loan with an interest rate of 4.75%.

GulfTerra Holding Term Credit Facility

As part of our April 2002 EPN Holding assets acquisition, we entered into a term credit facility to fund a portion of the purchase price. We repaid the $160 million balance of this term credit facility in July 2003 with proceeds from our issuance of $250 million of 6¼% senior notes due 2010. We recognized a loss of $1.2 million related to the write-off of unamortized debt issuance costs in connection with our repayment of this facility.

Senior Secured Acquisition Term Loan

As part of our November 2002 San Juan assets acquisition, we entered into a $237.5 million senior secured acquisition term loan to fund a portion of the purchase price. We repaid this senior secured acquisition term loan in March 2003 with proceeds from our issuance of $300 million 8½% senior subordinated notes due 2010. We recognized a loss of $3.8 million related to the write-off of unamortized debt issuance costs in connection with our repayment of this facility. From the issuance of the senior secured acquisition term loan in November 2002 to its repayment date, the interest rates on our revolving credit facility and GulfTerra Holding term credit facility were 2.25% over the variable base rate described above or LIBOR increased by 3.50%.

Senior Notes

In July 2003, we issued $250 million in aggregate principal amount of 6¼% senior notes due June 2010. We used the proceeds of approximately $245.1 million, net of issuance costs, to repay $160 million of indebtedness under the GulfTerra Holding term credit facility and to temporarily repay $85.1 million of the balance outstanding under our revolving credit facility. The interest on our senior notes is payable semi-annually in June and December with the principal maturing in June 2010. Our senior notes are unsecured obligations that rank senior to all our existing and future subordinated debt and equally with all of our existing and future senior debt, although they are effectively junior in right of payment to all of our existing and future senior secured debt to the extent of the collateral securing that debt.

We may redeem some or all of our senior notes, at our option, at any time with at least 30 days notice at a price equal to the greater of (1) 100 percent of the principal amount plus accrued interest, or (2) the sum of the present value of the remaining scheduled payments plus accrued interest.

Senior Subordinated Notes

Each issue of our senior subordinated notes is subordinated in right of payment to all existing and future senior debt, including our existing credit facility and the senior notes we issued in July 2003.

In March 2003, we issued $300 million in aggregate principal amount of 8½% senior subordinated notes. The interest on these notes is payable semi-annually in June and December, and the notes mature in June 2010. We used the proceeds of approximately $293.5 million, net of issuance costs, to repay $237.5 million of indebtedness under our senior secured acquisition term loan and to temporarily repay $55.5 million of the balance outstanding under our revolving credit facility. We may, at our option, prior to June 1, 2006, redeem up to 33 percent of the originally issued aggregate principal amount of these notes at a redemption price of 108.50 percent of the principal amount. We may redeem all or part of these notes at any time on or after June 1, 2007. The redemption price on that date is 104.25 percent of the principal amount, declining annually until it reaches 100 percent of the principal amount.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. At September 30, 2003, the fair value of the swap was a liability, included in non-current liabilities, of approximately $2.2 million. The fair value of the hedged debt decreased by the same amount.

Restrictive Provisions of Senior and Senior Subordinated Notes

Our senior and senior subordinated notes include provisions that, among other things, restrict our ability and the ability of our subsidiaries (excluding our unrestricted subsidiaries) to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies, and enter into sale and lease-back transactions, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries in addition to restricting our ability to make distributions to our unitholders. Many restrictive covenants associated with our senior notes will effectively be removed following a period of 90 consecutive days during which they are rated Baa3 or higher by Moody's or BBB– or higher by S&P, and some of the more restrictive covenants associated with some (but not all) of our senior subordinated notes will be suspended should they be similarly rated.

Other Credit Facilities

Poseidon

Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, is party to a $185 million credit agreement, under which it has $123 million outstanding at September 30, 2003. This credit agreement is secured by substantially all of Poseidon's assets and includes restrictions on, among other things, its ability to incur indebtedness, grant liens and make distributions to its owners. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced from 1.50% to 1.25% as a result of improvement in Poseidon's leverage ratio, as defined in its credit agreement. In April 2004, Poseidon's $185 million credit facility will mature; however, Poseidon is currently negotiating with lenders to replace this facility.

In January 2002, Poseidon entered into a two-year swap agreement to hedge the variable portion of its interest at 3.49% through January 2004 on $75 million of the $123 million outstanding. The effective interest rate on this hedged amount is 4.74% (the variable LIBOR based rate locked in at 3.49% plus a fixed margin of 1.25%) at September 30, 2003. As of September 30, 2003, the variable LIBOR-based rate on the unhedged amount of $48 million was at an interest rate of 2.38%.

Deepwater Gateway

At September 30, 2003, Deepwater Gateway, an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest, had $129 million outstanding under its construction loan at an average interest rate of 2.93%. This construction loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the construction loan will convert into a term loan with a final maturity date of July 2009. Upon conversion of the construction loan to a term loan, Deepwater Gateway will be required to maintain a debt service reserve equal to or greater than the projected principal, interest and fees due on the term loan for the immediately succeeding six month period. This construction loan is secured by substantially all of Deepwater Gateway's assets and includes restrictions on, among other things, its ability to incur indebtedness, grant liens and make distributions to its owners. Prior to conversion to the term loan, Deepwater Gateway is prohibited from making distributions.

Cameron Highway

Cameron Highway Oil Pipeline Company (Cameron Highway), an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest (See Note 10 for additional discussion relating to the formation of Cameron Highway), entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, each of which fund proportionately as construction costs are incurred.

The $225 million construction loan bears interest at Cameron Highway's option at each borrowing at either (i) 2.00% over the variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) 3.00% over LIBOR. Upon completion of the construction, the construction loan will convert to a term loan maturing July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly principal payments of $8.125 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by December 31, 2006, the construction loan and senior secured notes become fully due and payable. At September 30, 2003, Cameron Highway has $35 million outstanding under the construction loan at an average interest rate of 4.18%.

The interest rate on Cameron Highway's senior secured notes is 3.25% over the rate on 10-year U.S. Treasury securities. Principal payments of $4 million are due quarterly from September 2008 through December 2011, $6 million each from March 2012 through December 2012, and $5 million each from March 2013 through the principal maturity date of December 2013. At September 30, 2003, Cameron Highway has $28 million outstanding under the notes at an average interest rate of 7.31%.

Under the terms of its project loan facility, Cameron Highway must pay each of the lenders and the senior secured noteholders commitment fees of 0.5% per year on any unused portion of such lender's or noteholder's committed funds. The project loan facility as a whole is secured by (1) substantially all of Cameron Highway's assets, including, upon conversion, a debt service reserve capital account, and (2) all of the equity interest in Cameron Highway. Other than the pledge of our equity interest and our construction obligations under the relevant producer agreements, as discussed in Note 10, the debt is non-recourse to us. The construction loan and senior secured notes prohibit Cameron Highway from making distributions to us until the construction loan is converted into a term loan and Cameron Highway meets certain financial requirements.

Debt Maturity Table

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the next 5 years and in total thereafter are as follows at September 30, 2003 (in thousands):

2003	$ 2,500
2004	5,000
2005	5,000
2006	333,000
2007	140,000
Thereafter	1,405,000
Total long-term debt and other financing obligations, including current maturities	$1,890,500

7. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Grynberg. In 1997, we, along with numerous other energy companies, were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). We, along with numerous other energy companies, have also been named defendants in *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al,* filed in 1999 in the District Court of Stevens County, Kansas. Quinque has been dropped as a plaintiff and Will Price has been added. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The plaintiffs in this case seek certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that the plaintiffs contend these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification was denied in April 2003. Plaintiffs' motion to file another amended petition to narrow the proposed class to royalty owners of wells in Kansas, Wyoming and Colorado was granted on July 28, 2003. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

In connection with our April 2002 acquisition of the EPN Holding assets, subsidiaries of El Paso Corporation have agreed to indemnify us against all obligations related to existing legal matters at the acquisition date, including the legal matters involving Leapartners, L.P., City of Edinburg, Houston Pipe Line Company LP, and City of Corpus Christi discussed below.

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process natural gas in areas of western Texas related to an asset now owned by GulfTerra Holding. In May 2001, the court ruled in favor of Leapartners and entered a judgment against El Paso Field Services of approximately $10 million. El Paso Field Services filed an appeal with the Eighth Court of Appeals in El Paso, Texas. On August 15, 2003 the Court of Appeals reversed the lower's courts calculation of past judgment interest but otherwise affirmed the judgment. A motion for a rehearing was denied, a petition for review by the Texas Supreme Court will be filed.

Also, GulfTerra Texas Pipeline L.P., (GulfTerra Texas, formerly known as EPGT Texas Pipeline L.P.) now owned by GulfTerra Holding, was involved in litigation with the City of Edinburg concerning the City's claim that GulfTerra Texas was required to pay pipeline franchise fees under a contract the City had with Rio Grande Valley Gas Company, which was previously owned by GulfTerra Texas and is now owned by Southern Union Gas Company. An adverse judgment against Southern Union and GulfTerra Texas was rendered in Hidalgo County State District court in December 1998 and found a breach of contract, and held both GulfTerra Texas and Southern Union jointly and severally liable to the City for approximately $4.7 million. The judgment relied on the single business enterprise doctrine to impose contractual obligations on GulfTerra Texas and Southern Union's entities that were not parties to the contract with the City. GulfTerra Texas appealed this case to the Texas Supreme Court seeking reversal of the judgment rendered against GulfTerra Texas. The City sought a remand to the trial court of its claim of tortious interference against GulfTerra Texas. Briefs were filed and oral arguments were held in November 2002. In October 2003, the Texas Supreme Court issued an opinion in favor of GulfTerra Texas and Southern Union on all issues.

In December 2000, a 30-inch natural gas pipeline jointly owned by GulfTerra Intrastate, L.P. (GulfTerra Intrastate) now owned by GulfTerra Holding, and Houston Pipe Line Company LP ruptured in Mont Belvieu, Texas, near Baytown, resulting in substantial property damage and minor physical injury. GulfTerra Intrastate is the operator of the pipeline. Two lawsuits were filed in the state district court in Chambers County, Texas by eight plaintiffs, including two homeowners' insurers. The suits seek recovery for physical pain and suffering, mental anguish, physical impairment, medical expenses, and property damage. Houston Pipe Line Company has been added as an additional defendant. In accordance with the terms of the operating agreement, GulfTerra Intrastate has agreed to assume the defense of and to indemnify Houston Pipe Line Company. As of September 30, 2003, all but one claim has now been settled and these settlements had no impact on our financial statements. The remaining claim relates solely to property damages.

The City of Corpus Christi, Texas (the "City") is alleging that GulfTerra Texas and various Coastal entities owe it monies for past obligations under City ordinances that propose to tax GulfTerra Texas on its gross receipts from local natural gas sales for the use of street rights-of-way. No lawsuit has been filed to date. Some but not all of the GulfTerra Texas pipe at issue has been using the rights-of-way since the 1960's. In addition, the City demands that GulfTerra Texas agree to a going-forward consent agreement in order for the GulfTerra Texas pipe and Coastal pipe to have the right to remain in City rights-of-way.

In August 2002, we acquired the Big Thicket assets, which consist of the Vidor plant, the Silsbee compressor station and the Big Thicket gathering system located in east Texas, for approximately $11 million from BP America Production Company (BP). Pursuant to the purchase agreement, we have identified environmental conditions that we are working with BP and appropriate regulatory agencies to address. BP has agreed to indemnify us for exposure resulting from activities related to the ownership or operation of these facilities prior to our purchase (i) for a period of three years for non-environmental claims and (ii) until one year following the completion of any environmental remediation for environmental claims. Following expiration of these indemnity periods, we are obligated to indemnify BP for environmental or non-environmental claims. We, along with BP and various other defendants, have been named in the following two lawsuits for claims based on activities occurring prior to our purchase of these facilities.

Christopher Beverly and Gretchen Beverly, individually and on behalf of the estate of John Beverly v. GulfTerra GC, L.P., et, al. In June 2003, the plaintiffs sued us in state district court in Hardin County, Texas. The plaintiffs are the parents of John Christopher Beverly, a two year old child who died on April 15, 2002, allegedly as the result of his exposure to arsenic, benzene and other harmful chemicals in the water supply. Plaintiffs allege that several defendants are responsible for that contamination, including us and BP. Our connection to the occurrences that are the basis for this suit appears to be our August 2002 purchase of certain assets from BP, including a facility in Hardin County, Texas known as the Silsbee compressor station. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between GulfTerra and BP, GulfTerra requested that BP indemnify GulfTerra for any exposure. BP has thus far declined assuming the indemnity obligation and we filed notice to arbitrate BP's failure to indemnify us. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

Melissa Duvail, et. al., v. GulfTerra GC, L.P., et. al. In June 2003, seventy-four residents of Hardin County, Texas, sued us and others in state district court in Hardin County, Texas. The plaintiffs allege that they have been exposed to hazardous chemicals, including arsenic and benzene, through their water supply, and that the defendants are responsible for that exposure. As with the Beverly case, our connection with the occurrences that are the basis of this suit appears to be our August 2002 purchase of certain assets from BP, including a facility known as the Silsbee compressor station, which is located in Hardin County, Texas. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between us and BP, BP has agreed to indemnify us for this matter.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we will establish the necessary accruals. As of September 30, 2003, we had no reserves for our legal matters.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Environmental

Each of our operating segments is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of September 2003, we had a reserve of approximately $21 million for remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. As part of the November 2002 San Juan assets acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased up to the purchase price of $766 million. We will only be indemnified for unknown liabilities for up to three years from the purchase date of this acquisition. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased. We expect to make capital expenditures for environmental matters of approximately $10 million in the aggregate for the years 2003 through 2007, primarily to comply with clean air regulations.

While the outcome of our outstanding environmental matters cannot be predicted with certainty, based on the information known to date and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Rates and Regulatory Matters

Marketing Affiliate Notice of Proposed Rulemaking. In September 2001, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since our High Island Offshore System (HIOS) and Petal Gas Storage facility, including the 59-mile Petal gas pipeline, are interstate facilities as defined by the Natural Gas Act, the proposed regulations, if adopted by FERC, would dictate how HIOS and Petal conduct business and interact with all of our energy affiliates and El Paso Corporation's energy affiliates. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public conference was held in May 2002, providing an opportunity to comment further on the NOPR. Following the conference, we filed additional comments. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in the form proposed would, at a minimum, place additional administrative and operational burdens on us.

If the standards of conduct proposed by the NOPR are adopted by the FERC, we will be required to functionally separate our HIOS and Petal interstate facilities from our other businesses. Under the proposed rule, we would be required to dedicate employees to manage and operate our interstate facilities independently from our other non-jurisdictional facilities. This employee group would be required to function independently and would be prohibited from communicating non-public transportation information to affiliates. Separate office facilities and systems would be necessary because of the requirement to restrict affiliate access to interstate transportation information. The NOPR also limits the sharing of employees and officers with non-regulated entities. Because of the loss of synergies and shared employee restrictions, a disposition of the interstate facilities may be necessary for us to effectively comply with the rule. At this time, we cannot predict the outcome of this NOPR.

Negotiated Rate Policy. In July 2002, the FERC issued a Notice of Inquiry (NOI) that sought comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. In July 2003, FERC issued an order that prospectively prohibits pipelines from negotiating rates based upon natural gas commodity price indices and imposes certain new filing requirements to ensure the transparency of negotiated rate transactions. Requests for rehearing were filed on August 25, 2003 and remain pending. Even if the FERC denies the rehearing requests, we do not expect that the final order would have a material impact on us.

Cash Management Rule. On October 23, 2003, the FERC approved a final rule in which it requires that a FERC regulated entity file its cash management agreement with the FERC, maintain records of transactions involving its participation in the cash management program, compute its proprietary capital ratio quarterly based on criteria established by the FERC, and notify the FERC 45 days after the end of a calendar quarter whether its proprietary capital ratio falls below 30 percent and subsequently when its proprietary capital ratio returns to or exceeds 30 percent. In the final rule, FERC stated that the requirements imposed by the rule are not in the nature of a regulation governing participation in cash management programs and that the rule does not dictate the content or terms for participating in a cash management program. Although the order will be subject to rehearing, we do not think the final order will have a material effect on us.

Under the rule, we believe that both HIOS and Petal will be able to continue to participate in our cash management program. We are in the process of reviewing and revising our cash management agreements pursuant to guidance issued by the FERC in other interstate pipeline proceedings.

Pipeline Safety Notice of Proposed Rulemaking. In January 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. Comments on the NOPR were filed on April 30, 2003. At this time, we cannot predict the outcome of this NOPR.

Other Regulatory Matters. HIOS is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a FERC approved tariff that governs its operations, terms and conditions of service, and rates. We timely filed a required rate case for HIOS on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee and changes to depreciation rates and negative salvage amortization. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. As of July 1, 2003, HIOS implemented the requested rates, subject to a refund, and has established a reserve for its estimate of its refund obligation. We will continue to review our expected refund obligation as the rate case moves through the hearing process and may increase or decrease the amounts reserved for refund obligation as our expectation changes. We have responded, and are continuing to respond, as new requests are received, to the FERC staff's data requests. The FERC has scheduled a hearing on this matter commencing November 17, 2003.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October of 2002. We are taking numerous steps to determine the cause of the fuel differences, including a review of receipt and delivery measurement data. As of September 30, 2003, we had recorded fuel differences of approximately $9.4 million, which is included in other non-current assets. Depending on the outcome of our review, we expect to seek FERC approval to collect some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers will negatively impact our earnings.

In December 1999, GulfTerra Texas filed a petition with the FERC for approval of its rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to GulfTerra Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering service. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. GulfTerra Texas has established a reserve for refunds. In July 2002, GulfTerra Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. GulfTerra Texas' request for rehearing is pending before the FERC.

In July 2002, Falcon Gas Storage also requested late intervention and rehearing of the order. Falcon asserts that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering imbalance management services. Meanwhile in December 2002, GulfTerra Texas amended its Statement of Operating Conditions to provide shippers the option of resolving daily imbalances using a third-party imbalance service provider. Falcon objected to the changes, complaining that imbalance resolution is the lowest priority of service. GulfTerra Texas responded to Falcon's objection and untimely intervention, repeating its request that Falcon's intervention be dismissed.

In December 2002, GulfTerra Texas requested FERC approval of market-based rates for interstate gas storage services performed at its Wilson storage facility. The filing was in compliance with a requirement to rejustify its existing rates or request new rates by December 20, 2002. Falcon also intervened in this filing, complaining that market-based rates should be denied because of their complaint about access on the GulfTerra Texas pipeline for third party imbalance services. On May 15, 2003, the FERC approved Wilson's market based rate proposal and dismissed Falcon's complaint.

Falcon Gas Storage Company, Inc. and its affiliate Hill-Lake Gas Storage, L.P. ("Falcon") filed a formal complaint in March 2003 at the Railroad Commission of Texas claiming that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering hourly imbalance management services on the GulfTerra Texas system. GulfTerra Texas filed a response specifically denying Falcon's assertions and requesting that the complaint be denied. The Railroad Commission has set their case for hearing beginning on December 16, 2003.

While the outcome of all of our rates and regulatory matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Joint Ventures

We conduct a portion of our business through joint venture arrangements (including our Cameron Highway, Deepwater Gateway and Poseidon joint ventures) we form to construct, operate and finance the development of our onshore and offshore midstream energy businesses. We are obligated to make our proportionate share of additional capital contributions to our joint ventures only to the extent that they are unable to satisfy their obligations from other sources including proceeds from credit arrangements.

Other Matters

As a result of current circumstances generally surrounding the energy sector, the creditworthiness of several industry participants has been called into question. As a result of these general circumstances, we have established an internal group to monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

8. ACCOUNTING FOR HEDGING ACTIVITIES

A majority of our commodity purchases and sales, which relate to sales of oil and natural gas associated with our production operations, purchases and sales of natural gas associated with pipeline operations, sales of natural gas liquids associated with our processing plants and our gathering activities, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of $3.525 per MMBtu and pay a floating price based on the San Juan index. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative under mark-to-market accounting since it did not qualify for hedge accounting under SFAS No. 133. Through the acquisition date in 2002, we recognized a $0.4 million net gain, ($1.0 million loss in the third quarter of 2002 and $1.4 million gain in the fourth quarter of 2002) in the margin of our natural gas pipelines and plants segment. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under SFAS No. 133. In February and August 2003, we entered into additional derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. We are accounting for all of our San Juan gathering derivatives as cash flow hedges under SFAS No. 133. As of September 30, 2003, the fair value of these cash flow hedges was a liability of $2.4 million, as the market price at that date was higher than the hedge price of $4.23. For the nine months ended September 30, 2003, we reclassified approximately $8.4 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. No ineffectiveness exists in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

In connection with our GulfTerra Intrastate Alabama operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We have entered into cash flow hedges in 2002 and 2003 to offset the risk of increasing natural gas prices for our purchases to satisfy these sales contracts. As of September 30, 2003, the fair value of these cash flow hedges was a liability of $11 thousand, as the market price at that date was lower than the hedge price of $5.20. For the nine months ended September 30, 2003, we reclassified approximately $223 thousand of unrealized accumulated gain related to these derivatives from accumulated other comprehensive income to earnings as a reduction of cost of natural gas. No ineffectiveness existed in this hedging relationship because all purchase and sale prices were based on the same index and volumes as the hedge transaction.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable portion of its LIBOR based interest rate on $75 million of its $185 million variable rate revolving credit facility at 3.49% over the life of the swap. Prior to April 2003, under its credit facility, Poseidon paid an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced resulting in an effective fixed interest rate of 4.74% on the hedged notional amount. As of September 30, 2003, the fair value of its interest rate swap was a liability of $0.5 million, as the market interest rate was lower than the hedge rate of 4.99%, resulting in accumulated other comprehensive loss of $0.5 million. We included our 36 percent share of this liability of $0.2 million as a reduction of our investment in Poseidon and as a loss in accumulated other comprehensive income which we estimate will be reclassified to earnings proportionately over the next three months. Additionally, we have recognized as a reduction in income our 36 percent share of Poseidon's realized loss of $1.3 million for the nine months ended September 30, 2003, or $0.5 million, through our earnings from unconsolidated affiliates.

We estimate the entire $3.0 million of unrealized losses included in accumulated other comprehensive income at September 30, 2003, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next 15 months and approximately $2.9 million will be reclassified as a reduction to earnings over the next twelve months. When our derivative financial instruments are settled, the related amount in accumulated other comprehensive income is recorded in the income statement in operating revenues, cost of natural gas and other products, or interest and debt expense, depending on the item being hedged. The effect of reclassifying these amounts to the income statement line items is recording our earnings for the period at the "hedged price" under the derivative financial instruments.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we pay the counterparty a LIBOR based interest rate plus a spread of 4.20% and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. As of September 30, 2003, the fair value of the interest rate swap was a liability included in non-current liabilities of approximately $2.2 and the fair value of the hedged debt decreased by the same amount.

The counterparties for our San Juan hedging activities are J. Aron and Company, an affiliate of Goldman Sachs, and UBS Warburg. We do not require collateral and do not anticipate non-performance by these counterparties. Through June 2003, the counterparty for our GulfTerra Intrastate Alabama operations was El Paso Merchant Energy. Beginning in August 2003, the counterparty is UBS Warburg, and we do not require collateral or anticipate non-performance by this counterparty. The counterparty for Poseidon's hedging activity is Credit Lyonnais. Poseidon does not require collateral and does not anticipate non-performance by this counterparty. Wachovia Bank is our counterparty on our interest rate swap on the 8½% notes, and we do not require collateral or anticipate non-performance by this counterparty.

9. BUSINESS SEGMENT INFORMATION

Each of our segments are business units that offer different services and products that are managed separately since each segment requires different technology and marketing strategies. We have segregated our business activities into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

As a result of our sale of the Prince TLP and our nine percent overriding royalty interest in the Prince Field in April 2002, the results of operations from these assets are reflected as discontinued operations in our statements of income for all periods presented. Accordingly, the segment results do not reflect the results of operations for the Prince assets.

We measure segment performance using earnings before interest, income taxes, depreciation and amortization (EBITDA), which we formerly referred to as "Performance Cash Flows," or an asset's ability to generate income. EBITDA is our liquidity measure as our lenders are interested in whether we generate sufficient cash to meet our debt obligations as they become due. Accordingly, our revolving credit agreement and indentures utilize EBITDA to represent a measure of the cash flows from current operations. Our equity investors generally focus on our capacity to pay distributions or to grow our business, or both. As a result, our ability to generate cash from operations of the business to cover distributions, debt service, as well as to pursue growth opportunities, is an important measure of our liquidity.

We believe EBITDA is a useful measurement to our investors because it allows them to evaluate the effectiveness of our business and operations and our investments from an operational perspective, exclusive of the costs to finance those activities, income taxes and depreciation and amortization, none of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures.

Following are results as of and for the periods ended September 30:

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Other(1)	Total
			(In thousands)			
Quarter Ended September 30, 2003						
Revenue from external customers	$ 180,879	$ 83,040	$ 10,252	$ 5,185	$ 4,310	$ 283,666
Intersegment revenue	29	—	—	600	(629)	—
Depreciation, depletion and amortization	17,198	2,475	2,929	1,414	1,202	25,218
Operating income	61,712	22,146(2)	4,588	3,471	162	92,079
Earnings from unconsolidated affiliates	516	1,797	882	—	—	3,195
EBITDA	80,002	26,782(2)	7,518	4,885	N/A	N/A
Assets	2,227,900	444,253	314,192	163,000	132,424	3,281,769

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Other[(1)]	Total
			(In thousands)			
Quarter Ended September 30, 2002						
Revenue from external customers	$ 96,319	$ 9,450	$ 8,599	$ 3,595	$ 4,286	$ 122,249
Intersegment revenue	62	—	—	1,547	(1,609)	—
Depreciation, depletion and amortization	12,235	1,399	2,818	990	1,832	19,274
Operating income (loss)	31,188	5,911	2,637	2,961	(761)	41,936
Earnings from unconsolidated affiliates	—	3,168	—	—	—	3,168
EBITDA	44,436	11,271	5,455	4,522	N/A	N/A
Assets	1,420,312	187,432	311,205	122,025	87,973	2,128,947

(1) Represents predominately our oil and natural gas production activities as well as intersegment eliminations.

(2) Includes a $19 million gain recorded from the sale of our 50 percent interest in Cameron Highway to Valero Energy Corporation in July 2003 (See Note 10).

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Other[(1)]	Total
			(In thousands)			
Nine Months Ended September 30, 2003						
Revenue from external customers	$ 577,585	$232,926	$ 32,729	$ 15,668	$13,793	$ 872,701
Intersegment revenue	97	—	278	2,004	(2,379)	—
Depreciation, depletion and amortization	50,830	6,839	8,810	3,974	3,308	73,761
Operating income	182,366	35,795[(2)]	13,776	11,423	1,712	245,072
Earnings from unconsolidated affiliates	1,771	6,845	882	—	—	9,498
EBITDA	236,223	51,279[(2)]	22,587	15,397	N/A	N/A
Assets	2,227,900	444,253	314,192	163,000	132,424	3,281,769
Nine Months Ended September 30, 2002						
Revenue from external customers	$ 231,874	$ 28,026	$ 18,454	$ 13,222	$12,706	$ 304,282
Intersegment revenue	179	—	—	7,770	(7,949)	—
Depreciation, depletion and amortization	30,987	4,530	5,620	3,093	5,709	49,939
Operating income (loss)	79,715	16,383	4,635	15,477	(5,785)	110,425
Earnings from unconsolidated affiliates	—	10,541	—	—	—	10,541
EBITDA	111,733	34,055	10,255	24,837	N/A	N/A
Assets	1,420,312	187,432	311,205	122,025	87,973	2,128,947

(1) Represents predominately our oil and natural gas production activities as well as intersegment eliminations.

(2) Includes a $19 million gain recorded from the sale of our 50 percent interest in Cameron Highway to Valero Energy Corporation in July 2003 (See Note 10).

A reconciliation of our segment EBITDA to our net income is as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Natural gas pipelines & plants	$ 80,002	$ 44,436	$236,223	$111,733
Oil & NGL logistics	26,782	11,271	51,279	34,055
Natural gas storage	7,518	5,455	22,587	10,255
Platform services	4,885	4,522	15,397	24,837
Segment EBITDA	119,187	65,684	325,486	180,880
Plus: Other, nonsegment results	3,640	3,229	11,917	7,535
Earnings from unconsolidated affiliates	3,195	3,168	9,498	10,541
Income from discontinued operations	—	456	—	4,901
Cumulative effect of accounting change	—	—	1,690	—
Less: Interest and debt expense	33,197	22,070	99,521	55,362
Loss due to write-off of debt issuance costs	1,225	—	4,987	—
Noncash hedge loss	—	1,013	—	1,013
Depreciation, depletion and amortization	25,218	19,274	73,761	49,939
Cash distributions from unconsolidated affiliates	3,160	3,960	11,390	13,140
Minority interest	889	8	969	13
Net cash payment received from El Paso Corporation	2,120	1,954	6,238	5,752
Discontinued operations of Prince facilities	—	456	—	6,965
Net income	$ 60,213	$ 23,802	$151,725	$ 71,673

10. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for these investments are as follows:

Nine Months Ended September 30, 2003
(In thousands)

	Coyote	Deepwater Gateway	Poseidon	Total
Ownership interest	50%	50%	36%	
Operating results data:				
Operating revenues	$5,625	$—	$ 921,091	
Crude oil purchases	—	—	(888,459)	
Gross margin	5,625	—	32,632	
Other income	6	37	45	
Operating expenses	(511)	—	(2,934)	
Depreciation	(1,036)	—	(6,230)	
Other expenses	(560)	(5)	(4,157)	
Net income	$3,524	$32	$ 19,356	
Our share:				
Allocated income	$1,762	$16	$ 6,968	
Adjustments(1)	9	(16)	(123)	
Earnings from unconsolidated affiliates	$1,771	$—	$ 6,845	$ 9,498(2)
Allocated distributions	$2,750	$—	$ 8,640	$11,390

Nine Months Ended September 30, 2002
(In thousands)

	Poseidon
Ownership interest	36%
Operating results data:	
Operating revenues	$ 817,724
Crude oil purchases	(774,554)
Gross margin	43,170
Other income	74
Operating expenses	(2,493)
Depreciation	(6,190)
Other expenses	(5,218)
Net income	$ 29,343
Our share:	
Allocated income	$ 10,563
Adjustments[(1)]	(22)
Earnings from unconsolidated affiliate	$ 10,541
Allocated distributions	$ 13,140

(1) We recorded adjustments primarily for differences from estimated earnings reported in our Quarterly Report on Form 10-Q and actual earnings reported in the unaudited financial statements of our unconsolidated affiliates.

(2) Total earnings from unconsolidated affiliates includes a $882 thousand gain associated with the sale of our interest in Copper Eagle.

In June 2003, we formed Cameron Highway Oil Pipeline Company and contributed to this newly formed company the $458 million Cameron Highway oil pipeline system construction project. Cameron Highway is responsible for building and operating the pipeline, which is scheduled for completion during the third quarter of 2004.

In connection with the construction of the Cameron Highway oil pipeline, we entered into producer agreements with three major anchor producers, BP Exploration & Production Company (BP Exploration), BHP Billiton Petroleum (Deepwater), Inc. (BHP), and Union Oil Company of California (Unocal), which agreements were assigned to and assumed by Cameron Highway. The producer agreements require construction of the 390-mile Cameron Highway oil pipeline. We are obligated to make additional capital contributions to Cameron Highway to the extent that the construction costs for the pipeline exceed Cameron Highway's capital resources, including our initial equity contributions and proceeds from Cameron Highway's project loan facility.

In July 2003, we sold a 50 percent interest in Cameron Highway to Valero Energy Corporation for $86 million, forming a joint venture with Valero. Valero paid us approximately $70 million at closing, including $51 million representing 50 percent of the capital investment expended through that date for the pipeline project. In July 2003, we recognized $19 million as a gain from the sale of long-lived assets. In addition, Valero will pay us an additional sum of $16 million, $5 million to be paid once the system is completed and the remaining $11 million by the end of 2006. We expect to reflect the receipts of these additional amounts in the periods received as gains from the sale of long-lived assets in our income statement. In connection with the formation of the Cameron Highway joint venture, Valero agreed to pay their proportionate share of pipeline construction costs that exceed Cameron Highways's capital resources, including the initial equity contributions and proceeds from Cameron Highway's project loan facility.

The Cameron Highway oil pipeline system project is expected to be funded with 29 percent, or $133 million, equity through capital contributions from the Cameron Highway partners, which have already been made, and 71 percent debt through a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes. See Note 6 for additional discussion of the project loan facility.

11. RELATED PARTY TRANSACTIONS

Our transactions with related parties and affiliates are as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands)			
Revenues received from related parties				
Natural gas pipelines and plants	$18,054	$45,588	$67,068	$104,771
Oil and NGL logistics	6,842	6,608	22,686	19,833
Natural gas storage	—	—	—	67
Other	—	2,456	—	7,402
	$24,896	$54,652	$89,754	$132,073
Expenses paid to related parties				
Cost of natural gas, oil and other products	$ 6,191	$ 3,399	$26,988	$ 16,652
Operating expenses	22,229	15,289	68,039	38,905
	$28,420	$18,688	$95,027	$ 55,557
Reimbursements received from related parties				
Operating expenses	$ 659	$ 525	$ 1,860	$ 1,575

There have been no changes to our related party relationships, except as described below, from those described in Note 9 of our audited financial statements filed in our 2002 Form 10-K.

Revenues received from related parties for the quarters ended September 30, 2003 and 2002, were approximately 9 percent and 45 percent of our total revenue. Revenues received from related parties for the nine months ended September 30, 2003 and 2002, were approximately 10 percent and 43 percent of our total revenue. Also, we have undertaken efforts to reduce our transactions with El Paso Merchant Energy North America Company (Merchant Energy) and as of June 30, 2003, we replaced all our month-to-month arrangements that were previously with Merchant Energy with similar arrangements with third parties.

The following table provides summary data categorized by our related parties:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands)			
Revenues received from related parties				
El Paso Corporation				
El Paso Merchant Energy North America Company	$ 8,405	$25,486	$27,008	$ 61,705
El Paso Production Company	2,392	2,849	6,824	6,414
Tennessee Gas Pipeline Company	—	113	93	—
El Paso Field Services	14,086	24,898	55,816	63,870
Southern Natural Gas Company	13	112	13	49
El Paso Natural Gas Company	—	1,194	—	35
	$24,896	$54,652	$89,754	$132,073
Cost of natural gas, oil and other products purchased from related parties				
El Paso Corporation				
El Paso Merchant Energy North America Company	$ 6,041	$ 3,323	$21,746	$ 14,082
El Paso Production Company	—	—	—	2,251
Tennessee Gas Pipeline Company	—	37	—	227
El Paso Field Services	84	—	5,107	—
El Paso Natural Gas Company	14	—	31	—
Southern Natural Gas	52	39	104	92
	$ 6,191	$ 3,399	$26,988	$ 16,652
Operating expenses paid to related parties				
El Paso Corporation				
El Paso Field Services	$22,120	$15,176	$67,723	$ 38,547
Unconsolidated Subsidiaries				
Poseidon Oil Pipeline Company	109	113	316	358
	$22,229	$15,289	$68,039	$ 38,905
Reimbursements received from related parties				
Unconsolidated Subsidiaries				
Poseidon Oil Pipeline Company	$ 659	$ 525	$ 1,860	$ 1,575

At September 30, 2003, and December 31, 2002, our accounts receivable due from related parties was $49.5 million and $83.8 million. At September 30, 2003 and December 31, 2002, our accounts payable due to related parties was $44.1 million and $86.1 million.

Our accounts receivable due from related parties consisted of the following as of:

	September 30, 2003	December 31, 2002
	(In thousands)	
El Paso Corporation		
El Paso Production Company	$ 4,707	$ 4,346
El Paso Merchant Energy North America Company	12,539	30,512
Tennessee Gas Pipeline Company	1,389	930
El Paso Field Services	8,840	36,071
El Paso Natural Gas Company	3,915	1,033
Other	846	1,298
	32,236	74,190
Unconsolidated Subsidiaries		
Deepwater Gateway	3,223	9,636
Cameron Highway	14,055	—
Other	20	—
	17,298	9,636
Total	$49,534	$83,826

Our accounts payable due to related parties consisted of the following as of:

	September 30, 2003	December 31, 2002
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 8,104	$ 8,871
El Paso Production Company	3,993	14,518
El Paso Field Services	18,732	55,648
Tennessee Gas Pipeline Company	904	1,319
El Paso Natural gas Company	4,074	1,475
El Paso Corporation	4,827	4,181
Other	1,075	132
	41,709	86,144
Unconsolidated Subsidiaries		
Deepwater Gateway	2,267	—
Other	129	—
	2,396	—
Total	$44,105	$86,144

Other Matters

In connection with the sale of some of our Gulf of Mexico assets in January 2001, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and $2 million in the first quarter of 2004. The present value of the amounts due from El Paso Corporation were classified as follows:

	September 30, 2003	December 31, 2002
	(In thousands)	
Accounts receivable, net	$4,124	$ 8,403
Other noncurrent assets	—	1,960
	$4,124	$10,363

In addition to the related party transactions discussed above, pursuant to the terms of many of the purchase and sale agreements we have entered into with various entities controlled directly or indirectly by El Paso Corporation, we have been indemnified for potential future liabilities, expenses and capital requirements above a negotiated threshold. Specifically, an indirect subsidiary of El Paso Corporation has indemnified us for specific litigation matters to the extent the ultimate resolutions of these matters result in judgments against us. For a further discussion of these matters see Note 7, Commitments and Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We have made no such claims for reimbursement to date but we expect to make a claim for approximately $5 million for cost incurred in the third quarter and any additional costs which may be incurred in the fourth quarter of 2003, as costs exceeded the established thresholds during the third quarter of 2003.

We have also entered into capital contribution arrangements with entities owned by El Paso Corporation, including its regulated pipelines, in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. We have an agreement to receive $6.1 million, of which $3.0 million has been collected, from ANR Pipeline Company for our Phoenix project. As of September 30, 2003, we have received $10.5 million from ANR Pipeline and $7.0 million from El Paso Field Services for the Marco Polo natural gas pipeline. In October 2003, we collected $2 million from Tennessee Gas Pipeline for our Medusa project. These amounts are reflected as a reduction in project costs. Regulated pipelines often contribute capital toward the construction costs of gathering facilities owned by others which are, or will be, connected to their pipelines. El Paso Field Services' contribution is in anticipation of additional natural gas volumes that will flow through to its onshore natural gas processing facilities.

In August 2003, Arizona Gas Storage L.L.C., along with its 50 percent partner APACS Holdings L.L.C., sold their interest in Copper Eagle Gas Storage L.L.C. to El Paso Natural Gas Company (EPNG), a subsidiary of El Paso Corporation. Copper Eagle Gas Storage is developing a natural gas storage project located outside of Phoenix, Arizona. Arizona Gas Storage is an indirect 60 percent owned subsidiary of GulfTerra Energy Partners, L.P. and 40 percent owned by IntraGas US, a Gaz de France North American subsidiary. APACS Holdings L.L.C. is a wholly owned subsidiary of Pinnacle West Energy, a subsidiary of Pinnacle West Capital Corporation. GulfTerra has the right to receive $6.2 million of the sale proceeds, including a note receivable for $4.9 million to be paid quarterly over the next twelve months, from EPNG and recorded a gain of $882 thousand related to the sale of Copper Eagle. In the event of EPNG default, the Copper Eagle Gas Storage project will revert back to the original owners without compensation to EPNG.

In September 2003, we entered into a nonbinding letter of intent with Southern Natural Gas Company, a subsidiary of El Paso Corporation, regarding the proposed development and sale of a natural gas storage cavern and the proposed sale of an undivided interest in a pipeline and other facilities related to that natural gas storage cavern. The new storage cavern would be located at our storage complex near Hattiesburg, Mississippi. If Southern Natural Gas determines that there is sufficient market interest, it would purchase the land and mineral rights related to the proposed storage cavern and would pay our costs to construct the storage cavern and related facilities. Upon completion of the storage cavern, Southern Natural Gas would acquire an undivided interest in our Petal pipeline connected to the storage cavern. We would also enter into an arrangement with Southern Natural Gas under which we would operate the storage cavern and pipeline on its behalf.

Before we consummate this transaction, and enter into definitive transaction documents, the transaction must be recommended by the audit and conflicts committee of our board of directors, which committee consists solely of directors meeting the independent director requirements established by the NYSE and the Sarbanes-Oxley Act and then approved by our general partner's full board of directors.

In October 2003, we exchanged with El Paso Corporation its obligation to repurchase the Chaco plant from us in 19 years for additional assets (refer to Note 2). Also in October 2003, we redeemed all of our outstanding Series B preference units (refer to Note 3).

The counterparty for one of our San Juan hedging activities is J. Aron and Company, an affiliate of Goldman Sachs, the owner of a 9.9 percent membership interest in our general partner. Goldman Sachs was also a co-manager of our 4,800,000 public common unit offering in October 2003, and is one of the lenders under our revolving credit facility.

12. GUARANTOR FINANCIAL INFORMATION

As of September 30, 2003, our credit facility is guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and our general partner, and is collateralized by our general partner's general and administrative services agreement and substantially all of our assets. In addition, all of our senior notes and senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and all of our subsidiaries, excluding our unrestricted subsidiaries. The consolidating eliminations column on our condensed consolidating balance sheets below eliminates our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries. The consolidating eliminations column in our condensed consolidating statements of income and cash flows eliminates earnings from our consolidated affiliates.

Non-guarantor subsidiaries as of and for the quarter and nine months ended September 30, 2003, consisted of our unrestricted subsidiaries. Non-guarantor subsidiaries as of and for the quarters ended September 30, 2002 and June 30, 2002, consisted of our GulfTerra Holding (then known as EPN Holding) subsidiaries, which owned the EPN Holding assets and equity interests in GulfTerra Holding (then known as EPN Holding). Non-guarantor subsidiaries for the quarter ended March 31, 2002 consisted of Argo and Argo I, which owned the Prince TLP. As a result of our disposal of the Prince TLP and our related overriding royalty interest in April 2002, the results of operations and net book value of these assets are reflected as discontinued operations in our statements of income and assets held for sale in our balance sheets and Argo and Argo I became guarantor subsidiaries.

Condensed Consolidating Statements of Income
For the Quarter Ended September 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$155	$283,511	$ —	$283,666
Operating expenses					
Cost of natural gas and other products	—	—	134,112	—	134,112
Operation and maintenance	1,139	85	49,997	—	51,221
Depreciation, depletion and amortization	37	10	25,171	—	25,218
(Gain) loss on sale of long-lived assets	(19,000)	—	36	—	(18,964)
	(17,824)	95	209,316	—	191,587
Operating income	17,824	60	74,195	—	92,079
Other income (loss)					
Earnings from consolidated affiliates	57,192	—	—	(57,192)	—
Earnings from unconsolidated affiliates	—	882	2,313	—	3,195
Minority interest expense	—	(889)	—	—	(889)
Other income	153	—	97	—	250
Interest and debt expense	14,956	—	18,241	—	33,197
Loss due to write-off of debt issuance costs	—	—	1,225	—	1,225
Net income	$ 60,213	$ 53	$ 57,139	$(57,192)	$ 60,213

Condensed Consolidating Statements of Income
For the Quarter Ended September 30, 2002

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$63,776	$58,473	$ —	$122,249
Operating expenses					
Cost of natural gas and other products	—	20,340	7,427	—	27,767
Operation and maintenance	832	14,596	17,410	—	32,838
Depreciation, depletion and amortization	38	5,305	13,931	—	19,274
Loss on sale of long-lived assets	—	—	434	—	434
	870	40,241	39,202	—	80,313
Operating income (loss)	(870)	23,535	19,271	—	41,936
Other income (loss)					
Earnings from consolidated affiliates	14,121	—	13,922	(28,043)	—
Earnings from unconsolidated affiliates	—	—	3,168	—	3,168
Minority interest expense	—	(8)	—	—	(8)
Other income (loss)	317	11	(8)	—	320
Interest and debt expense	(10,234)	9,616	22,688	—	22,070
Income from continuing operations	23,802	13,922	13,665	(28,043)	23,346
Income from discontinued operations	—	—	456	—	456
Net income	$23,802	$13,922	$14,121	$(28,043)	$ 23,802

Condensed Consolidating Statements of Income
For the Nine Months Ended September 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$661	$872,040	$ —	$872,701
Operating expenses					
Cost of natural gas and other products	—	—	432,159	—	432,159
Operation and maintenance	4,344	227	135,845	—	140,416
Depreciation, depletion and amortization	111	31	73,619	—	73,761
(Gain) loss on sale of long-lived assets	(19,000)	—	293	—	(18,707)
	(14,545)	258	641,916	—	627,629
Operating income	14,545	403	230,124	—	245,072
Other income (loss)					
Earnings from consolidated affiliates	181,589	—	—	(181,589)	—
Earnings from unconsolidated affiliates	—	882	8,616	—	9,498
Minority interest expense	—	(969)	—	—	(969)
Other income	605	—	337	—	942
Interest and debt expense	41,252	—	58,269	—	99,521
Loss due to write-off of debt issuance costs	3,762	—	1,225	—	4,987
Income from continuing operations	151,725	316	179,583	(181,589)	150,035
Cumulative effect of accounting change	—	—	1,690	—	1,690
Net income	$151,725	$316	$181,273	$(181,589)	$151,725

Condensed Consolidating Statements of Income
For the Nine Months Ended September 30, 2002

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
		(In thousands)			
Operating revenues	$ —	$125,232	$179,050	$ —	$304,282
Operating expenses					
Cost of natural gas and other products	—	39,280	27,988	—	67,268
Operations and maintenance	4,901	27,642	43,988	—	76,531
Depreciation, depletion and amortization	237	10,719	38,983	—	49,939
Loss on sale of long-lived assets	—	—	119	—	119
	5,138	77,641	111,078	—	193,857
Operating income (loss)	(5,138)	47,591	67,972	—	110,425
Other income (loss)					
Earnings from consolidated affiliates	43,014	—	29,539	(72,553)	—
Earnings from unconsolidated affiliates	—	—	10,541	—	10,541
Minority interest expense	—	(13)	—	—	(13)
Other income	1,179	5	(3)	—	1,181
Interest and debt expense	(32,618)	22,048	65,932	—	55,362
Income from continuing operations	71,673	25,535	42,117	(72,553)	66,772
Income from discontinued operations	—	4,004	897	—	4,901
Net income	$ 71,673	$ 29,539	$ 43,014	$(72,553)	$ 71,673

Condensed Consolidating Balance Sheets
September 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 58,944	$ —	$ —	$ —	$ 58,944
Accounts receivable, net					
Trade	—	110	125,137	—	125,247
Affiliates	767,329	3,527	49,551	(770,873)	49,534
Affiliated note receivable	—	4,951	17,100	—	22,051
Other current assets	3,680	—	16,292	—	19,972
Total current assets	829,953	8,588	208,080	(770,873)	275,748
Property, plant and equipment, net	7,271	441	2,792,377	—	2,800,089
Intangible assets	—	—	3,426	—	3,426
Investment in unconsolidated affiliates	—	—	157,375	—	157,375
Investment in consolidated affiliates	2,060,103	—	520	(2,060,623)	—
Other noncurrent assets	204,706	—	10,424	(169,999)	45,131
Total assets	$3,102,033	$9,029	$3,172,202	$(3,001,495)	$3,281,769
Current liabilities					
Accounts payable					
Trade	$ —	$ 38	$ 107,083	$ —	$ 107,121
Affiliates	15,873	3,520	795,585	(770,873)	44,105
Accrued interest	42,071	—	270	—	42,341
Current maturities of senior secured term loan	5,000	—	—	—	5,000
Other current liabilities	4,179	1	13,743	—	17,923
Total current liabilities	67,123	3,559	916,681	(770,873)	216,490
Revolving credit facility	328,000	—	—	—	328,000
Senior secured term loans, less current maturities	152,500	—	—	—	152,500
Long-term debt	1,405,271	—	—	—	1,405,271
Other noncurrent liabilities	2,244	—	197,903	(169,999)	30,148
Minority interest	—	2,465	—	—	2,465
Partners' capital	1,146,895	3,005	2,057,618	(2,060,623)	1,146,895
Total liabilities and partners' capital	$3,102,033	$9,029	$3,172,202	$(3,001,495)	$3,281,769

Condensed Consolidating Balance Sheets
December 31, 2002

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 20,777	$ —	$ 15,322	$ —	$ 36,099
Accounts receivable, net					
Trade	—	74	139,445	—	139,519
Affiliates	709,230	3,055	67,513	(695,972)	83,826
Affiliated note receivable	—	—	17,100	—	17,100
Other current assets	1,118	—	2,333	—	3,451
Total current assets	731,125	3,129	241,713	(695,972)	279,995
Property, plant and equipment, net	6,716	454	2,717,768	—	2,724,938
Intangible assets	—	—	3,970	—	3,970
Investment in unconsolidated affiliates	—	5,197	73,654	—	78,851
Investment in consolidated affiliates	1,787,767	—	693	(1,788,460)	—
Other noncurrent assets	205,262	—	7,879	(169,999)	43,142
Total assets	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896
Current liabilities					
Accounts payable					
Trade	$ —	$ 302	$ 126,422	$ —	$ 126,724
Affiliates	18,867	2,982	760,267	(695,972)	86,144
Accrued interest	14,221	—	807	—	15,028
Current maturities of senior secured term loan	5,000	—	—	—	5,000
Other current liabilities	1,645	5	19,545	—	21,195
Total current liabilities	39,733	3,289	907,041	(695,972)	254,091
Revolving credit facility	491,000	—	—	—	491,000
Senior secured term loans, less current maturities	392,500	—	160,000	—	552,500
Long-term debt	857,786	—	—	—	857,786
Other noncurrent liabilities	(1)	—	193,725	(169,999)	23,725
Minority interest	—	1,942	—	—	1,942
Partners' capital	949,852	3,549	1,784,911	(1,788,460)	949,852
Total liabilities and partners' capital	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896

Condensed Consolidating Statements of Cash Flows
For the Nine Months Ended September 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 151,725	$ 316	$ 181,273	$(181,589)	$ 151,725
Less cumulative effect of accounting change	—	—	1,690	—	1,690
Income from continuing operations	151,725	316	179,583	(181,589)	150,035
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	111	31	73,619	—	73,761
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	(882)	(8,616)	—	(9,498)
Distributions from unconsolidated affiliates	—	—	11,390	—	11,390
Gain on sale of long-lived assets	(19,000)	—	293	—	(18,707)
Write-off of debt issuance costs	3,762	—	1,225	—	4,987
Other noncash items	6,683	1,165	(5,875)	—	1,973
Working capital changes, net of effects of acquisitions and noncash transactions	69,286	(375)	(73,497)	—	(4,586)
Net cash provided by operating activities	212,567	255	178,122	(181,589)	209,355
Cash flows from investing activities					
Additions to property, plant and equipment	(666)	(18)	(245,611)	—	(246,295)
Proceeds from sale of assets	69,836	—	7,612	—	77,448
Proceeds from sale of investments in unconsolidated affiliates	—	1,342	—	—	1,342
Additions to investments in unconsolidated affiliates	—	(214)	(33,665)	—	(33,879)
Net cash provided by (used in) investing activities	69,170	1,110	(271,664)	—	(201,384)
Cash flows from financing activities					
Net proceeds from revolving credit facility	298,000	—	—	—	298,000
Repayments of revolving credit facility	(461,000)	—	—	—	(461,000)
Repayment of senior secured acquisition term loan	(237,500)	—	—	—	(237,500)
Repayment of GulfTerra Holding term loan	—	—	(160,000)	—	(160,000)
Repayment of senior secured term loan	(2,500)	—	—	—	(2,500)
Net proceeds from issuance of long-term debt	537,537	—	—	—	537,537
Net proceeds from issuance of common units and Series F convertible units	208,949	—	—	—	208,949
Advances with affiliates	(419,086)	(723)	238,220	181,589	—
Distributions to partners	(167,974)	—	—	—	(167,974)
Distributions to minority interests	—	(642)	—	—	(642)
Contribution from General Partner	4	—	—	—	4
Net cash provided by (used in) financing activities	(243,570)	(1,365)	78,220	181,589	14,874
Increase (decrease) in cash and cash equivalents	$ 38,167	$ —	$ (15,322)	$ —	22,845
Cash and cash equivalents					
Beginning of period					36,099
End of period					$ 58,944
Schedule of noncash investing and financing activities:					
Investment in Cameron Highway Oil Pipeline Company Joint Venture	$ 50,836	$ —	$ —	$ —	$ 50,836
Redemption of Series B preference units contributed from our General Partner	$ 1,986	$ —	$ —	$ —	$ 1,986

Condensed Consolidating Statements of Cash Flows
For the Nine Months ended September 30, 2002

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 71,673	$ 29,539	$ 43,014	$(72,553)	$ 71,673
Less income from discontinued operations	—	4,004	897	—	4,901
Income from continuing operations	71,673	25,535	42,117	(72,553)	66,772
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	237	10,719	38,983	—	49,939
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(10,541)	—	(10,541)
Distributions from unconsolidated affiliates	—	—	13,140	—	13,140
Loss on sale of long-lived assets	—	—	119	—	119
Other noncash items	3,300	(5,175)	3,068	—	1,193
Working capital changes, net of effects of acquisitions and noncash transactions	30,354	(13,620)	(3,820)	—	12,914
Net cash provided by (used in) continuing operations	105,564	17,459	83,066	(72,553)	133,536
Net cash provided by discontinued operations	—	4,631	376	—	5,007
Net cash provided by (used in) operating activities	105,564	22,090	83,442	(72,553)	138,543
Cash flows from investing activities					
Additions to property, plant and equipment	(3,618)	(14,060)	(128,866)	—	(146,544)
Proceeds from sale of assets	—	—	5,460	—	5,460
Additions to investments in unconsolidated affiliates	—	—	(30,364)	—	(30,364)
Cash paid for acquisitions, net cash acquired	—	(730,166)	(11,250)	—	(741,416)
Net cash used in investing activities of continuing operations	(3,618)	(744,226)	(165,020)	—	(912,864)
Net cash provided by (used in) investing activities of discontinued operations	—	(3,523)	190,000	—	186,477
Net cash provided by (used in) investing activities	(3,618)	(747,749)	24,980	—	(726,387)
Cash flows from financing activities					
Net proceeds from revolving credit facility	278,731	—	—	—	278,731
Repayments of revolving credit facility	(10,000)	—	—	—	(10,000)
Net proceeds from GulfTerra Holding term loan	—	530,529	—	—	530,529
Repayment of senior secured term loan	—	(375,000)	—	—	(375,000)
Repayment of Argo term loan	—	—	(95,000)	—	(95,000)
Net proceeds from issuance of long-term debt	229,576	—	—	—	229,576
Net proceeds from issuance of common units	150,397	—	—	—	150,397
Advances with affiliates	(631,633)	585,686	(26,606)	72,553	—
Distributions to partners	(112,752)	—	—	—	(112,752)
Contribution from General Partner	560	—	—	—	560
Net cash provided by (used in) financing activities of continuing operations	(95,121)	741,215	(121,606)	72,553	597,041
Net cash used in financing activities of discontinued operations	—	(3)	—	—	(3)
Net cash provided by (used in) financing activities	(95,121)	741,212	(121,606)	72,553	597,038
Increase (decrease) in cash and cash equivalents	$ 6,825	$ 15,553	$ (13,184)	$ —	9,194
Cash and cash equivalents					
Beginning of period					13,084
End of period					$ 22,278

13. NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51

In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*. This interpretation defines a variable interest entity (VIE) as a legal entity whose equity owners have neither sufficient equity at risk nor a controlling financial interest in the entity. This standard requires a company to consolidate any VIE if it is allocated a majority of the VIE's losses and/or returns, including fees paid by the VIE.

The provisions of FIN No. 46 for all VIE's created after January 31, 2003, was effective February 1, 2003. Our adoption of this standard for VIE's created after January 31, 2003, did not have an effect on our financial position or results of operations.

On October 9, 2003, the FASB issued FIN 46-6, *Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities.* The staff position deferred the effective date for interests held by public entities in variable interest entities or potential variable interest entities created before February 1, 2003. The new effective date, for the variable interest entities covered under FIN 46-6, is for the period ending after December 15, 2003. We continue to evaluate our joint venture and financing arrangements created before February 1, 2003, to assess the impact, if any, of FIN No. 46 on these arrangements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in Part II, Items 7, 7A and 8, in our Annual Report on Form 10-K for the year ended December 31, 2002, in addition to the interim financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

This quarter, we completed the sale of a 50 percent interest in Cameron Highway Oil Pipeline to Valero Energy Corporation (Valero). Cameron Highway also entered into its construction financing arrangements. We also improved the partnership's financial flexibility by upsizing our revolving credit facility from $600 million to $700 million and extended the maturity from May 2004 to September 2006. Refer to "Liquidity and Capital Resources" below for further discussion regarding the renewal of our revolving credit facility and Cameron Highway financing agreement.

We continued to integrate our 2002 EPN Holding and San Juan acquisitions by exchanging with El Paso Corporation in October 2003 its obligation to repurchase the Chaco plant from us in 19 years for additional assets (refer to "Exchange with El Paso Corporation" below for further discussion) related to our November 2002 San Juan assets acquisition. Also in October 2003, El Paso Corporation completed the sale of 9.9 percent of our general partner to Goldman, Sachs & Co. (Goldman Sachs) and we redeemed all of our outstanding Series B preference units. The sale of the 9.9 percent interest in our general partner substantially completed our 2003 corporate governance and independence goals. We also completed a 4,800,000 common unit public offering in October 2003, achieving our goal to reduce the partnership's debt to total capital ratio to a level below 60 percent.

Industry Perspective

We believe the midstream sector is in a period of substantial and ongoing change, which will provide significant growth opportunities for well-positioned companies. We expect large and mid-size energy companies, including potentially El Paso Corporation, to continue to divest midstream assets in an effort to strengthen their balance sheets as well as to focus on core businesses. These divestitures may produce attractive acquisition opportunities for us. In addition, we believe the midstream sector is likely to experience substantial consolidation through mergers and acquisitions. This consolidation may well result in a few large, independent midstream businesses, a number of which we believe will be MLPs, becoming the leading participants in this business sector.

General Partner Relationship

Our corporate governance structure and independence initiatives

In October 2003, Goldman Sachs made a $200 million investment in us and our general partner acquiring a 9.9 percent membership interest in our general partner from El Paso Corporation for $88 million and 3,000,000 common units from us for $112 million. Adding a co-owner of our general partner was one of the major steps of our Independence Initiatives, which we identified as necessary elements of functioning, and being evaluated by the capital markets, as a stand-alone, independent operating company.

We have continued to improve our corporate governance model, which currently meets the standards established by the Securities and Exchange Commission (SEC) and New York Stock Exchange (NYSE). During the first quarter of 2003, we identified and evaluated a number of changes that could be made to our corporate structure to better address potential conflicts of interest and to better balance the risks and rewards of significant relationships with our affiliates, which we refer to as Independence Initiatives. Through October 2003, we have already implemented the following initiatives:

- added an additional independent director to our board of directors, bringing the number of independent directors to four of the six-member board;

- established a governance and compensation committee of our board of directors, consisting solely of independent directors, which is responsible for establishing performance measures and making recommendations to El Paso Corporation concerning compensation of its employees performing duties for us;
- changed our name to GulfTerra Energy Partners, L.P.;
- received a letter of credit from El Paso Merchant Energy North America totaling $5.1 million regarding our existing customer/contractual relationships with them;
- completed a resource support agreement with El Paso Corporation;
- modified our partnership agreement to: (1) eliminate El Paso Corporation's right to vote its common units with respect to the removal of the general partner; (2) effectively reduce the third-party common unit vote required to remove the general partner from 72 percent to 67 percent; and (3) require the unanimous vote of the general partner's board of directors before the general partner or we can voluntarily initiate bankruptcy proceedings;
- reorganized our structure, further reducing our interrelationships with El Paso Corporation, resulting in our general partner being a Delaware limited liability company that is not permitted to have:
  - material assets other than its interest in us;
  - material operations other than those relating to our operations;
  - material debt or other obligations other than those owed to us or our creditors;
  - material liens other than those securing obligations owed to us or our creditors; or
  - employees; and
- added Goldman Sachs as a co-owner of our general partner.

Additionally, as part of implementing our Independence Initiatives, we are considering adding one more independent director to our board of directors. We will continue to evaluate our Independence Initiatives and analyze whether additional actions are desirable.

Our relationship with El Paso Corporation

El Paso Corporation, a NYSE-listed company, is a leading provider of natural gas services and the largest pipeline company in North America. Through its subsidiaries, El Paso Corporation:

- owns 90.1 percent of our general partner. Historically, El Paso Corporation and its affiliates have employed the personnel who operate our businesses. We reimburse our general partner and its affiliates for the costs they incur on our behalf, and we pay our general partner its proportionate share of distributions —relating to its one percent general partnership interest and the related incentive distributions —we make to our partners each calendar quarter.
- is a significant stake-holder in us — it owns approximately 19.0 percent, or 11,084,245, of our common units (decreased from 26.5 percent as a result of our common unit offerings during the second and third quarters of 2003 and decreased from 23.1 percent as a result of our October 2003 offerings and its sale of 590,000 common units in October 2003), all 10,937,500 of our Series C units, which we issued in November 2002 for $350 million, and 90.1 percent of our general partner. As holders of some of our common units and all of our Series C units, subsidiaries of El Paso Corporation receive their proportionate share of distributions we make to our partners each calendar quarter. In July 2003, we filed a registration statement on Form S-3 to register for resale 2,000,000 of the common units owned by El Paso Corporation or its subsidiaries. Under this registration statement, El Paso Corporation sold 590,000 of its common units in October 2003.
- is a customer of ours. As with other large energy companies, we have entered into a number of contracts with El Paso Corporation and its affiliates.

As discussed above, we have implemented, and may further implement, a number of Independence Initiatives that are designed to help us better manage the rewards and risks relating to our relationship with El Paso Corporation. However, even in light of these Independence Initiatives or any other arrangements, we may still be adversely affected if El Paso Corporation continues to suffer financial stress.

Goldman Sachs' Investment in Our General Partner and Common Units

In connection with our Independence Initiatives, El Paso Corporation decided to sell between 5 and 10 percent of its interest in our general partner (which was then a wholly owned subsidiary of El Paso Corporation) and solicit bids from interested investors. Goldman Sachs was the successful bidder and in October 2003, Goldman Sachs acquired a 9.9 percent membership interest in our general partner for $88 million. In connection with its investment in our general partner, Goldman Sachs also purchased 3,000,000 common units from us for $112 million. Our general partner's Audit and Conflicts Committee engaged an independent financial advisor to provide a fairness opinion related to the sale of our general partner interest. Based on this opinion, these transactions were approved by the Audit and Conflicts Committee of our general partner's board of directors and its full board of directors.

Through Goldman Sachs' membership interest in our general partner:

- it is entitled to receive 9.9 percent of all distributions made by our general partner; and
- its consent is required before we or our general partner can liquidate, dissolve or file a voluntary bankruptcy petition.

In connection with Goldman Sachs' investment, we entered into the following agreements with El Paso Corporation and its affiliates and Goldman Sachs:

Exchange and Registration Rights Agreement. Under this agreement:

- Beginning in October 2008, Goldman Sachs will have the right to exchange its 9.9 percent membership interest in our general partner for a number of common units that would result in Goldman Sachs receiving quarterly common unit distributions, based on the most recent cash distribution to common unitholders, equal (subject to adjustments) to 9.9 percent of the most recent cash distribution we have made to our general partner;
- The maximum number of common units that Goldman Sachs will be permitted to receive in exchange for its entire membership interest in our general partner may not exceed 9.9 percent of the sum of the total number of our outstanding limited partner interests (calculated on a diluted basis) plus the number of common units to be issued to Goldman Sachs in the exchange. However, Goldman Sachs will not be permitted to receive a number of common units at any point in time that, together with any other common units owned by Goldman Sachs, would result in Goldman Sachs owning more than 9.9 percent of our outstanding common units at that time.
- Goldman Sachs will have the right to effect the exchange prior to October 2008 upon the occurrence of specified events, including:
  - the sale of all or substantially all of our or our general partner's assets,
  - our merger with another company,
  - a change of control (as that term is defined in the Exchange and Registration Rights Agreement) of the El Paso Corporation subsidiary that owns 90.1 percent of our general partner,
  - our liquidation,
  - our distribution of cash from interim capital contributions (as defined in our partnership agreement),

    - in certain circumstances, the commencement of a voluntary or involuntary bankruptcy proceeding against El Paso Corporation or any of its material subsidiaries, or
    - if we negotiate a reduction in the incentive distributions that we pay to our general partner;

- Beginning in October 2010, or prior to October 2010 upon the occurrence of certain events, we will have, and in certain instances El Paso Corporation has, the right to cause Goldman Sachs to exchange its 9.9 percent membership interest in our general partner for common units;
- We have filed with the SEC, and have agreed to maintain the effectiveness of, a shelf registration statement to register the 3,000,000 common units we issued to Goldman Sachs as well as any common units Goldman Sachs acquires in any exchange for its interest in our general partner; and
- Goldman Sachs agreed not to sell pursuant to the shelf registration statement any of the 3,000,000 units it acquired from us for a minimum of 90 days, subject to certain exceptions (including upon a sale of common units by us, El Paso Corporation or any of its subsidiaries before that date).

Incentive Distribution Reduction Agreement. Under this agreement, if we acquire Goldman Sachs' interest in our general partner under the Exchange and Registration Rights Agreement, we will then return that interest to our general partner in exchange for a reduction in our general partner's incentive distribution payments based on the amount of the distributions attributable to the membership interest exchanged.

Exchange With El Paso Corporation

In connection with our November 2002 San Juan assets acquisition, El Paso Corporation retained the obligation to repurchase the Chaco plant from us for $77 million in October 2021. As part of El Paso Corporation's sale of 9.9 percent of our general partner, we released El Paso Corporation from that obligation in exchange for El Paso Corporation contributing specified assets to us. The communications assets we received will be used in the operation of our pipeline systems, furthering our independence strategy. Prior to the October 2003 exchange, we were paying a fee to El Paso Corporation for the use of their assets. We recorded the received assets at El Paso Corporation's book value with the offset to partners' capital. In connection with the exchange, El Paso Corporation also agreed to provide us with the right to lease 80 percent of an office building in San Antonio, Texas at no cost for 20 years.

As a result of the October 2003 exchange, we changed our accounting estimate of the depreciable life of the Chaco Plant, from 19 to 30 years in order to depreciate the Chaco Plant over its estimated useful life as compared to the original term of the repurchase agreement. Depreciation expense will decrease approximately $0.5 million and $2.3 million on a quarter and annual basis.

Series B Preference Units

In October 2003, we redeemed all 123,865 of our remaining outstanding Series B preference units for $156 million, a 7 percent discount from their liquidation value of $167 million. For this redemption, we used the net proceeds of $111.5 million from our sale of 3,000,000 common units to Goldman Sachs, and $44.1 million from cash on hand and from borrowings under our revolving credit facility. We reflected the discount as an increase to the common units capital, Series C units capital and to our general partner capital accounts.

Fairness Opinion

In accordance with our procedures for evaluating and valuing material transactions with El Paso Corporation, our general partner's Audit and Conflicts Committee engaged an independent financial advisor to provide a fairness opinion related to the transactions with Goldman Sachs, the asset exchange with El Paso Corporation, and the redemption of Series B Preference Units. Based on this opinion, our Audit and Conflicts Committee and the full Board approved these transactions.

Cameron Highway Oil Pipeline Company

In June 2003, we formed Cameron Highway Oil Pipeline Company and contributed to it the $458 million Cameron Highway oil pipeline system construction project. Cameron Highway is responsible for building and operating the pipeline, which is scheduled for completion during the third quarter of 2004. We entered into producer agreements with three major anchor producers, BP Exploration & Production Company (BP Exploration), BHP Billiton Petroleum (Deepwater), Inc. (BHP) and Union Oil Company of California (Unocal), which agreements were assigned to and assumed by Cameron Highway. The producer agreements require construction of the 390-mile Cameron Highway oil pipeline.

In July 2003, we sold a 50 percent interest in Cameron Highway to Valero for $86 million, forming a joint venture with Valero. Valero paid us approximately $70 million at closing, including $51 million representing 50 percent of the capital investment expended through that date for the pipeline project, and we recognized $19 million as a gain from the sale of long-lived assets. In addition, Valero will pay us $5 million once the system is completed and an additional $11 million by the end of 2006. We expect to reflect these additional amounts as gains from the sale of long-lived assets in the periods they are received.

The Cameron Highway oil pipeline system project is expected to be funded with 29 percent, or $133 million, equity through capital contributions from the Cameron Highway partners (currently, Valero and us), which have already been made, and 71 percent debt through a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes. We and Valero are obligated to make additional capital contributions to Cameron Highway if and to the extent that the construction costs for the pipeline exceed Cameron Highway's capital resources, including the initial equity contributions and proceeds from Cameron Highway's project loan facility.

Related Party Transactions

In our normal course of business we enter into transactions with various entities controlled directly or indirectly by El Paso Corporation.

For the quarter ended September 30, 2003, $8.4 million of our related party revenue came from Merchant Energy for natural gas transportation and storage agreements. In November 2002, El Paso Corporation announced its intention to exit the energy trading business. Currently, we have a $5.1 million letter of credit from Merchant Energy representing two months of transportation revenues. During the quarter ended September 30, 2003, Merchant Energy continued to fully utilize these agreements. As of June 30, 2003, we replaced all our month-to-month, market priced sales of natural gas to Merchant Energy with similar arrangements with third parties. In October 2003, Merchant Energy transferred the natural gas transportation and storage agreements they have with us to El Paso Field Services.

In connection with our San Juan assets acquisition, we entered into a 10-year transportation agreement with El Paso Field Services beginning January 1, 2003. Under this agreement, we receive a fee of $1.5 million per year for transportation on one of our NGL pipelines.

The fees we incur for services under our general and administrative services agreement with El Paso Corporation reflect the benefit from El Paso Corporation's ability to utilize their economies of scale to negotiate service levels at favorable costs. During 2002, these fees increased as a result of the acquisitions of the EPN Holding and San Juan assets. We expect the management fee will continue to be adjusted to reflect increases in services provided. We anticipate we will continue to obtain these services from El Paso Corporation; however, if these services were to end, our expenditures may increase as we may not be able to obtain the same level of services at comparable costs.

See Part I, Financial Information, Note 11 for a further discussion of our related party transactions.

Liquidity and Capital Resources

Our principal requirements for cash, other than our routine operating costs, are for capital expenditures, debt service, business acquisitions and distributions to our partners. We plan to fund our short-term cash needs, including operating costs, maintenance capital expenditures and cash distributions to our partners, from cash generated from our operating activities and borrowings under our credit facility. Capital expenditures we expect to benefit us over longer time periods, including our organic growth projects and business acquisitions, we plan to fund through a variety of sources (either separately or in combination), which include issuing additional common units, borrowing under commercial bank credit facilities, issuing public or private placement debt and other financing transactions. We plan to fund our debt service requirements through a combination of refinancing arrangements and cash generated from our operating activities.

The ability to execute our growth strategy and complete our projects is dependent upon our access to the capital necessary to fund the projects and acquisitions. Our success with capital raising efforts, including the formation of joint ventures to share costs and risks, continues to be the critical factor which determines how much we actually spend. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs and, although we currently intend to make the forecasted expenditures discussed below, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in the capital markets.

Capital Resources

Common Units

Our announced strategy for 2003 is to continue to finance or re-finance our growth with 50 percent equity to ensure a sound capital structure. Since January 2003, we have raised net proceeds of approximately $387.5 million through public offerings of 11,026,109 common units, successfully accomplishing part of our strategy for 2003. We used the net proceeds from our public offerings of common units to temporarily reduce amounts outstanding under our revolving credit facility and for general partnership purposes. The following table provides additional detail regarding our public offerings since January 2003:

Public Offering Date	Common Units Issued	Public Offering Price	Net Offering Proceeds
		(per unit)	(in millions)
October 2003	4,800,000	$40.60	$186.1
August 2003	507,228	$39.43	$ 19.7
June 2003	1,150,000	$36.50	$ 40.3
May 2003	1,118,881	$35.75	$ 38.3
April 2003	3,450,000	$31.35	$103.1

In addition to our public offerings of common units, in October 2003 we sold 3,000,000 common units privately to Goldman Sachs in connection with their purchase of a 9.9 percent membership interest in our general partner. We used the net proceeds of $111.5 million from that private sale to partially fund the redemption of all of our outstanding Series B preference units.

We expect to use the proceeds we receive from any additional capital we raise through the issuance of additional common units to temporarily reduce amounts outstanding under our credit facility, to finance growth opportunities and for general partnership purposes. Our ability to raise additional capital may be negatively affected by many factors, including our relationship with El Paso Corporation.

Series B Preference Units

In connection with our 2003 public offerings of common units through September 30, 2003, our general partner, in lieu of a cash contribution, contributed to us, and we retired, 1,527 Series B preference units with liquidation value of approximately $2.0 million, including accrued distributions of approximately $0.5 million, to maintain its one percent general partner interest. In October 2003, we redeemed all of our remaining outstanding Series B preference units. Refer to previous discussion "Series B Preference Units", for further discussion.

Series F Convertible Units

In connection with our public offering of 1,118,881 common units in May 2003, we issued 80 Series F convertible units. Each Series F convertible unit is comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that have identical terms except for vesting and termination times and the number of underlying common units into which they may be converted. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until March 29, 2004 (subject to defined extension rights). The Series F2 units are convertible into up to $40 million of common units provided at least $40 million of Series F1 convertible units are converted prior to their termination. The Series F2 units terminate on March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75 or the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units; (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units assuming we had received a conversion notice on September 30 and October 29, 2003, was $38.77 and $39.05. The Series F units may be converted into a maximum of 8,329,679 common units. Holders of Series F convertible units are not entitled to vote or receive distributions. The value associated with the Series F convertible units is included in partners' capital as a component of common units capital.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26.00 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at September 30, 2003.

Indebtedness and Other Obligations

In March 2003, we issued $300 million in aggregate principal amount of 8½% senior subordinated notes due 2010. We used the proceeds of approximately $293.5 million, net of issuance costs, to repay all indebtedness outstanding under our $237.5 million senior secured acquisition term loan and to temporarily repay $55.5 million of the balance outstanding under our revolving credit facility.

In July 2003, we issued $250 million in aggregate principal amount of 6¼% senior notes due 2010. We used the proceeds of approximately $245.1 million, net of issuance costs, to repay the remaining $160 million of indebtedness under the GulfTerra Holding term credit facility and the remaining $85.1 million to temporarily reduce amounts outstanding under our revolving credit facility.

In July 2003, Cameron Highway Oil Pipeline Company, our 50 percent owned joint venture that is constructing the 390-mile Cameron Highway Oil Pipeline, entered into a $325 million project loan facility consisting of a $225 million construction loan and $100 million of senior secured notes. At September 30, 2003, Cameron Highway had $35 million outstanding under the construction loan and $28 million of senior secured notes outstanding.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we pay the counterparty a LIBOR based interest rate plus a spread of 4.20% and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. At September 30, 2003, the fair value of the swap was a liability, included in non-current liabilities, of approximately $2.2 million. The fair value of the hedged debt decreased by the same amount.

In September 2003, we renewed our credit facility to among other things, increase the commitment level under the revolving component from $600 million to $700 million and extend the maturity from May 2004 to September 2006. Under the terms of our renewed credit facility, the interest rate we are charged is contingent upon our leverage ratio, as defined in our credit facility, and ratings we are assigned by S&P or Moody's. The interest we are charged would increase by 0.25% if the credit ratings on our senior secured credit facility decrease or our leverage ratio decreases, or alternatively, would decrease by 0.25% if these ratings are increased or our leverage ratio improves. Additionally, we pay commitment fees on the unused portion of our revolving credit facility at rates that vary from 0.30% to 0.50%. These increases in our credit facility costs are the only additional costs we would bear in direct relationship to our financing contracts.

See Part I, Financial Information, Note 6, for a detailed discussion of our debt obligations.

The following table presents the timing and amounts of our debt repayment and other obligations for the years following September 30, 2003, that we believe could affect our liquidity (in millions):

Debt Repayment and Other Obligations	<1 Year	1-3 Years	3-5 Years	After 5 Years	Total
Revolving credit facility	$ —	$328	$ —	$ —	$ 328
Senior secured term loan	5	10	143	—	158
6¼% senior notes issued July 2003, due June 2010	—	—	—	250	250
10⅜% senior subordinated notes issued May 1999, due June 2009	—	—	—	175	175
8½% senior subordinated notes issued March 2003, due June 2010	—	—	—	300	300
8½% senior subordinated notes issued May 2001, due June 2011	—	—	—	250	250
8½% senior subordinated notes issued May 2002, due June 2011	—	—	—	230	230
10⅝% senior subordinated notes issued November 2002, due December 2012	—	—	—	200	200
Wilson natural gas storage facility operating lease	3	10	11	—	24
Total debt repayment and other obligations	$ 8	$348	$154	$1,405	$1,915

Capital Expenditures

Forecasted Expenditures

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our operating and growth objectives. These estimates may change due to factors beyond our control, such as weather related issues, changes in supplier prices or poor economic conditions. Further, estimates may change as a result of decisions made at a later date, which may include acquisitions, scope changes or decisions to take on additional partners. Our projection of expenditures for the quarters ended September 30, June 30 and March 31, 2003 as presented in our 2002 Annual Report on Form 10-K, were $78, $92 and $120 million; however, our actual expenditures were approximately $39, $125 and $80 million.

The table below depicts our estimate of projects and capital maintenance expenditures through September 30, 2004. These expenditures are net of project financings and anticipated contributions in aid of construction and contributions from joint venture partners. We expect to be able to fund these forecasted expenditures from the combination of operating cash flow and funds available under our revolving credit facility and other financing arrangements. Actual results may vary from these projections.

	Quarters Ending				Net Total Forecasted Expenditures
	December 31, 2003	March 31, 2004	June 30, 2004	September 30, 2004	
	(In millions)				
Net Forecasted Capital Project Expenditures	$80	$41	$17	$20	$158
Other Forecasted Capital Expenditures	11	15	10	10	46
Total Forecasted Expenditures	$91	$56	$27	$30	$204

Construction Projects

	Capital Expenditures				Capacity		
	Forecasted		As of September 30, 2003				
	Total(1)	GulfTerra(2)	Total(1)	GulfTerra(2)	Oil	Natural Gas	Expected Completion
	(In millions)				(MBbls/d)	(MMcf/d)	
Wholly owned projects							
Medusa Natural Gas Pipeline	$ 28	$ 26	$ 23	$ 23	—	160	Fourth Quarter 2003
Marco Polo Natural Gas and Oil Pipelines	101	84	49	32	120	400	First Quarter 2004
Phoenix Gathering System	66	60	23	20	—	450	Second Quarter 2004
Joint venture projects							
Marco Polo Tension Leg Platform(3)	224	33	182	33	120	300	Fourth Quarter 2003
Cameron Highway Oil Pipeline(4)	458	85	176	85	500	—	Third Quarter 2004

(1) Includes 100 percent of costs and is not reduced for anticipated contributions in aid of construction, project financings and contributions from joint venture partners. We expect to receive $6.1 million of which $3.0 million has been collected from ANR Pipeline Company for our Phoenix project. We have received $10.5 million from ANR Pipeline Company and $7.0 million from El Paso Field Services for the Marco Polo natural gas pipeline. In October 2003, we collected $2 million from Tennessee Gas Pipeline for our Medusa project.

(2) GulfTerra expenditures are net of anticipated or received contributions in aid of construction, project financings and contributions from joint venture partners to the extent applicable.

(3) Forecasted expenditures increased during the first quarter of 2003 due to increases in gas processing capacity (from 250 to 300 MMcf/d) and oil processing capacity (from 100 to 120 MBbls/d) and a higher builder's risk insurance cost.

(4) In July 2003, we sold a 50 percent interest in Cameron Highway to Valero Energy Corporation. Valero paid us approximately $51 million at closing representing 50 percent of the capital investment expended through that date.

Projects Announced in 2003

Front Runner Downstream Oil Pipeline Project. In September 2003, we announced that Poseidon, our 36 percent owned joint venture, entered into an agreement for the purchase and sale of crude oil from the Front Runner Field. Poseidon will construct, own and operate the $28 million project, which will connect the Front Runner Field with Poseidon's existing system at Ship Shoal Block 332. The new 36-mile, 14-inch pipeline is expected to be operational by the middle of 2004 and have a capacity of 65,000 barrels per day. As Poseidon expects to fund Front Runner's capital expenditures from its operating cash flow and from its revolving credit facility, we do not expect to receive distributions from Poseidon until the Front Runner pipeline is completed.

San Juan Optimization Project. In May 2003, we announced the approval of a $43 million project relating to our San Juan Basin assets. The project is expected to be completed in stages through 2006. The project is expected to result in a 130 MMcf/d increase in capacity, added compression to the Chaco processing facility and increased market opportunities through a new interconnect at the tailgate of the Chaco processing facility. As of September 30, 2003, we have spent approximately $1.5 million related to this project.

Petal Expansion Project. In September 2003, we entered into a nonbinding letter of intent with Southern Natural Gas Company, a subsidiary of El Paso Corporation, regarding the proposed development and sale of a natural gas storage cavern and the proposed sale of an undivided interest in a pipeline and other facilities related to that natural gas storage cavern. The new storage cavern would be located at our storage complex near Hattiesburg, Mississippi. If Southern Natural Gas determines that there is sufficient market interest, it would purchase the land and mineral rights related to the proposed storage cavern and would pay our costs to construct the storage cavern and related facilities. Upon completion of the storage cavern, Southern Natural Gas would acquire an undivided interest in our Petal pipeline connected to the storage cavern. We would also enter into an arrangement with Southern Natural Gas under which we would operate the storage cavern and pipeline on its behalf.

Before we consummate this transaction, and enter into definitive transaction documents, the transaction must be recommended by the audit and conflicts committee of our general partner's board of directors, which committee consists solely of directors meeting the independent director requirements established by the NYSE and the Sarbanes-Oxley Act and then approved by our general partner's full board of directors.

Acquisitions

San Juan Assets

During the quarter ended September 30, 2003, the total purchase price and net assets acquired for our November 2002 acquisition of the San Juan assets decreased $2.4 million due to post-closing purchase price adjustments related to natural gas imbalances, NGL in-kind reserves and well loss reserves. The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	At November 27, 2002
	(In thousands)
Note receivable	$ 17,100
Property, plant and equipment	763,696
Intangible assets	470
Investment in unconsolidated affiliate	2,500
Total assets acquired	783,766
Imbalances payable	17,403
Other current liabilities	2,565
Total liabilities assumed	19,968
Net assets acquired	$763,798

EPN Holding

During the nine months ended September 30, 2003, the total purchase price and net assets acquired for the April 2002 EPN Holding asset acquisition increased $17.5 million due to post-closing purchase price adjustments related primarily to natural gas imbalances assumed in the transaction. The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	At April 8, 2002
	(In thousands)
Current assets	$ 4,690
Property, plant and equipment	780,648
Intangible assets	3,500
Total assets acquired	788,838
Current liabilities	15,229
Environmental liabilities	21,136
Total liabilities assumed	36,365
Net assets acquired	$752,473

Cash From Operating Activities

Net cash provided by operating activities was $209.4 million for the nine months ended September 30, 2003, compared to $138.5 million for the same period in 2002. The increase was attributable to operating cash flows generated by our acquisitions of the EPN Holding assets in April 2002 and the San Juan assets in November 2002.

Cash Used In Investing Activities

Net cash used in investing activities was approximately $201.4 million for the nine months ended September 30, 2003. Our investing activities include capital expenditures related to the construction of the Marco Polo pipelines, the Cameron Highway oil pipeline, and the Falcon Nest fixed-leg platform offset in part by $69.8 million in proceeds from the sale of a 50 percent interest in Cameron Highway to Valero, $1.3 million in proceeds from the sale of our interest in Copper Eagle and $7.6 million from the sale and retirement of other assets.

Cash From Financing Activities

Net cash provided by financing activities was approximately $14.9 million for the nine months ended September 30, 2003. During 2003, our cash provided by financing activities included issuances of long-term debt and offerings of common units and convertible units. Cash used in our financing activities included repayments on our senior secured acquisition term loan, our revolving credit facility and other financing obligations, as well as distributions to our partners.

Other Matters

As a result of current circumstances generally surrounding the energy sector, the creditworthiness of several industry participants has been called into question, including El Paso Corporation, the indirect owner of 90.9 percent of our general partner. As a result of these circumstances, we have established an internal group to monitor our exposure to, and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties. During the second quarter of 2003, we received a letter of credit from Merchant Energy totaling $5.1 million regarding our existing customer/contractual relationships with them. If these general conditions worsen and, as a result, several industry participants file for Chapter 11 bankruptcy protection, it could have a material adverse effect on our financial position, results of operations or cash flows. While some industry participants have filed for Chapter 11 bankruptcy protection during the past nine months, our exposure to these participants has not been significant. However, based upon our review of the collectibility of accounts receivable, we increased our allowance by $2.0 million during the second quarter of 2003. As of September 30, 2003 and December 31, 2002, our allowance was $4.5 million and $2.5 million.

Results of Operations

Our business activities are segregated into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

As a result of our sale of the Prince TLP and our nine percent overriding interest in the Prince Field in April 2002, the results of operations from these assets are reflected as discontinued operations in our statements of income for all periods presented and are not reflected in our segment results below.

To the extent possible, results of operations have been reclassified to conform to the current business segment presentation, although these results may not be indicative of the results which would have been achieved had the revised business segment structure been in effect during those periods. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. For a further discussion of the individual segments, see Part I, Financial Information, Note 9.

Consolidated Results

We reported third quarter 2003 net income of $60.2 million ($0.62 per unit), up 152 percent from $23.8 million ($0.21 per unit) from third quarter 2002. Earnings before interest, taxes, depreciation, and amortization (EBITDA) increased 78 percent to $122.8 million in the third quarter 2003 compared with $68.9 million in the third quarter of 2002.

For the nine months ended September 30, 2003, net income was $151.7 million ($1.56 per unit), a 112-percent increase as compared to $71.7 million ($0.72 per unit) for the same nine months ended 2002. EBITDA for the nine months ended September 30, 2003 was $337.4 million, an increase of 79 percent from the $188.4 million reported for the same period of 2002.

We use EBITDA to assess our consolidated and segment results. EBITDA is our liquidity measure as our lenders are interested in whether we generate sufficient cash to meet our debt obligations as they become due. Accordingly, our revolving credit agreement and indentures utilize EBITDA to represent a measure of our cash flows from current operations. Our equity investors generally focus on our capacity to pay distributions or to grow the business, or both. As a result, our ability to generate cash from operations of the business to cover distributions, debt service, as well as to pursue growth opportunities, is an important measure of our liquidity. A reconciliation of this measure to cash flows from operations for our consolidated results is as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Cash Flows from Operations	$ 75,189	$ 76,942	$209,355	$138,543
Plus: Interest and debt expense	33,197	22,070	99,521	55,362
Working capital changes, net of effects of acquisitions and noncash transactions	(10,079)	(33,428)	4,586	(12,914)
Gain (loss) on sale of long-lived assets	18,964	(434)	18,707	(119)
Minority interest	889	8	969	13
Net cash payment received from El Paso Corporation	2,120	1,954	6,238	5,752
Noncash hedge loss	—	1,013	—	1,013
Discontinued operations of Prince facilities	—	456	—	6,965
Less: Net cash provided by (used in) discontinued operations	—	(30)	—	5,007
Noncash items on cash flow statement	(2,547)	(302)	1,973	1,193
EBITDA	$122,827	$ 68,913	$337,403	$188,415

Segment Results

The following table presents EBITDA by segment and in total.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands)			
Natural gas pipelines and plants	$ 80,002	$44,436	$236,223	$111,733
Oil and NGL logistics	26,782	11,271	51,279	34,055
Natural gas storage	7,518	5,455	22,587	10,255
Platform services	4,885	4,522	15,397	24,837
Segment EBITDA	119,187	65,684	325,486	180,880
Other, net	3,640	3,229	11,917	7,535
Consolidated EBITDA	$122,827	$68,913	$337,403	$188,415

See Item 1, Financial Information, Note 9 for a reconciliation of segment EBITDA to net income.

Natural Gas Pipelines and Plants

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands, except for volumes)			
Natural gas pipelines and plants revenue	$180,908	$ 96,381	$ 577,682	$232,053
Cost of natural gas and other products	(64,611)	(27,767)	(240,631)	(67,268)
Natural gas pipelines and plants margin	116,297	68,614	337,051	164,785
Operating expenses excluding depreciation, depletion, and amortization	(37,387)	(25,191)	(103,855)	(54,083)
Other income (expense)	598	(8)	1,958	5
Noncash hedge loss	—	1,013	—	1,013
Cash distributions from unconsolidated affiliates in excess of earnings[1]	484	—	979	—
Minority interest	10	8	90	13
EBITDA	$ 80,002	$ 44,436	$ 236,223	$111,733

[1] Earnings from unconsolidated affiliates for the quarter and nine months ended September 30, 2003, was $516 thousand and $1,771 thousand.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands, except for volumes)			
Volumes (MDth/d)				
Texas Intrastate	3,402	3,235	3,387	2,237
San Juan gathering	1,263	—	1,212	—
Permian gathering	306	320	327	238
HIOS	643	696	700	750
Viosca Knoll gathering	704	583	688	569
Other natural gas pipelines	638	391	618	387
Processing plants	794	746	795	718
Total volumes	7,750	5,971	7,727	4,899

We provide natural gas gathering and transportation services for a fee. However, agreements with some of our customers require that we purchase natural gas from producers at the wellhead for an index price less an amount that compensates us for gathering services. We then sell the natural gas into the open market at points on our system at the same price paid to the producers. Accordingly, under these agreements, our operating revenues and costs of natural gas and other products are impacted by changes in energy commodity prices, however, our margin for these agreements reflects only the fee we received for gathering services. At our Indian Basin processing facility, our revenues reflect the gross sales of natural gas liquids we retain as a processing fee and the natural gas liquids purchased from other producers under the marketing provisions of their contracts. Included in our cost of natural gas and other products is the payment to the producers for the natural gas liquids we marketed on their behalf. For these reasons, we feel that gross margin (revenue less cost of natural gas and other products) provides a more accurate and meaningful basis for analyzing operating results for this segment. Revenues at our Chaco processing facility are representative of our processing fee since the natural gas liquids purchased from the producers at this facility is minimal.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October of 2002. We are taking numerous steps to determine the cause of the fuel differences, including a review of receipt and delivery measurement data. As of September 30, 2003, we had recorded fuel differences of approximately $9.4 million, which is included in other non-current assets. Depending on the outcome of our review, we expect to seek FERC approval to collect some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers will negatively impact the future results of our natural gas pipelines and plants segment.

Third Quarter Ended September 30, 2003 Compared With Third Quarter Ended September 30, 2002

Natural gas pipelines and plants margin for the quarter ended September 30, 2003, was $47.7 million higher than in the same period in 2002. Our San Juan Basin assets, acquired in November 2002, accounted for approximately $44.8 million of the increase. Margin also increased by approximately $2.0 million due to an increase in volumes attributable to our Falcon Nest pipeline, which was placed in service in March 2003, and additional volumes on our Viosca Knoll system from the Canyon Express pipeline system. Additionally, margin increased by approximately $1.3 million due to higher NGL prices in 2003, which favorably impacted margins at our Indian Basin processing facility. Partially offsetting these increases was a decrease in volumes on our HIOS pipeline due to naturally declining production in the western regions of the Gulf of Mexico.

Operating expenses excluding depreciation, depletion, and amortization for the quarter ended September 30, 2003, were $12.2 million higher than the same period in 2002 primarily due to the acquisition of the San Juan Basin assets. Excluding the operating costs of these acquired assets, operating expenses increased by $6.6 million due to higher repair and maintenance expenses of $1.9 million on our Texas intrastate pipeline, which were unusually low in 2002 due to timing of expenditures, and $1.3 million attributable to repairs on our Medusa gas pipeline, which was damaged by an anchor after construction. Additionally, operating expenses were higher by $3.1 million due to an increase associated with our general and administrative services agreement with subsidiaries of El Paso Corporation, as a result of our acquisitions in 2002.

Other income for the quarter ended September 30, 2003, primarily relates to earnings from our unconsolidated affiliate, Coyote Gas Treating, LLC, which we acquired in connection with the San Juan asset acquisition in November 2002.

The noncash hedge loss for the quarter ended September 30, 2002, is related to our San Juan hedging activity prior to our acquisition of the San Juan assets in November 2002. Prior to this acquisition we accounted for our San Juan hedging activity under mark-to-market accounting since it did not qualify for hedge accounting under SFAS No. 133.

Nine Months Ended September 30, 2003 Compared With Nine Months Ended September 30, 2002

Natural gas pipelines and plants margin for the nine months ended September 30, 2003, was $172.3 million higher than in the same period in 2002. Our San Juan Basin assets, acquired in November 2002, and our EPN Holding assets, acquired in April 2002, accounted for approximately $130.0 million and $36.7 million of the increase. Margin also increased by $6.0 million due to an increase in volumes attributable to our Falcon Nest pipeline, which was placed in service in March 2003, and additional volumes on our Viosca Knoll system from the Canyon Express pipeline system. Additionally, margin increased by $3.0 million due to higher NGL prices in 2003, which favorably impacted margins at our Indian Basin processing facility. Partially offsetting these increases was a $1.0 million decrease in margin for our Texas intrastate pipeline system attributable to the impact that higher natural gas prices in 2003 had on our fuel costs and the revaluation of our natural gas imbalances, offset by an increase in base business performance. The increases were also offset by an additional $2.9 million decrease in margin related to lower volumes on our HIOS pipeline due to natural decline in the western region of the Gulf of Mexico.

Operating expenses excluding depreciation, depletion, and amortization for the nine months ended September 30, 2003, were $49.8 million higher than the same period in 2002 primarily due to the acquisition of the San Juan Basin and EPN Holding assets. Excluding the operating costs of these acquired assets, operating expenses increased by $21.4 million due to increased operating expenses of $13.3 million associated with our general and administrative services agreement with subsidiaries of El Paso Corporation. The increase in operating expenses is also attributable to an increase in our allowance for doubtful accounts of $2.0 million, higher repair and maintenance expenses of $6.3 million, of which $5.0 million relates to expenditures on our Texas intrastate pipeline, which were unusually low in 2002 due to timing of expenditures, and $1.3 million attributable to repairs on our Medusa gas pipeline, which was damaged by an anchor after construction.

Other income for the nine months ended September 30, 2003, primarily relates to earnings from our unconsolidated affiliate, Coyote Gas Treating, LLC, which we acquired in connection with the San Juan asset acquisition in November 2002.

The noncash hedge loss for the nine months ended September 30, 2002, is related to our San Juan hedging activity prior to our acquisition of the San Juan assets in November 2002. Prior to this acquisition we accounted for our San Juan hedging activity under mark-to-market accounting since it did not qualify for hedge accounting under SFAS No. 133.

Oil and NGL Logistics

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands, except for volumes)			
Oil and NGL logistics revenues	$ 83,040	$ 9,450	$ 232,926	$ 28,026
Cost of natural gas and other products	(70,302)	—	(192,307)	—
Oil and NGL logistics margin	12,738	9,450	40,619	28,026
Operating expenses excluding depreciation, depletion, and amortization and gain from sale of Cameron Highway	(7,117)	(2,139)	(16,985)	(7,111)
Gain on sale of long-lived assets(3)	19,000	—	19,000	—
Other income	1,798	3,168	6,850	10,541
Cash distributions from unconsolidated affiliates in excess of earnings(1)	363	792	1,795	2,599
EBITDA	$ 26,782	$ 11,271	$ 51,279	$ 34,055
Volume (Bbl/d)				
Texas NGL Fractionation	52,159	70,597	59,267	72,499
Texas NGL Systems	34,609	—	30,350	—
Allegheny Oil Pipeline	12,017	17,395	14,500	17,570
Typhoon Oil Pipeline	27,868	—	25,909	—
Unconsolidated affiliate				
Poseidon Oil Pipeline(2)	116,555	131,457	134,898	140,344
Total volumes	243,208	219,449	264,924	230,413

(1) Earnings from unconsolidated affiliates for the quarter and nine months ended September 30, 2003, was $1,797 thousand and $6,845 thousand. Earnings from unconsolidated affiliates for the quarter and nine months ended September 30, 2002, was $3,168 thousand and $10,541 thousand.

(2) Represents 100 percent of the volumes flowing through the pipeline, in which we own a 36 percent joint venture interest.

(3) Represents a gain of $19 million associated with the sale of our 50 percent interest in Cameron Highway to Valero Energy Corporation in July 2003. Refer to previous discussion regarding "Cameron Highway Oil Pipeline Company."

The majority of the earnings from the oil and NGL logistics segment are generated from volume-based fees for providing transportation of oil and NGL and fractionation of NGL. However, many of the agreements with the customers on our oil pipelines require that we purchase oil from the customer at the inlet of our pipeline for an index price, less an amount that compensates us for transportation services, and resell the oil to the customer at the outlet of our pipeline at the same index price. Although the effect of these transactions is that we receive a volume-based fee for our services, our operating revenue and cost of natural gas and other products include the index price that we pay and receive. For these reasons, we believe that gross margin (revenue less cost of natural gas and other products) provides a more accurate and meaningful basis for analyzing operating results for this segment.

Gross margin is driven by product pricing for both oil and NGL and volumes. Both oil and NGL volumes are impacted by natural resource decline as well as increases in new production. Volumes at our Texas NGL fractionation facilities are significantly impacted by processing economics, which are driven by the difference between natural gas prices and NGL prices. In 2003, natural gas prices have been high relative to NGL prices resulting in poor processing economics that reduce the amount of NGL extracted from natural gas and available for fractionation. We expect these economics to continue into next year.

Third Quarter Ended September 30, 2003 Compared With Third Quarter Ended September 30, 2002

For the quarter ended September 30, 2003, margin was $3.3 million higher than the same period in 2002. Our Texas NGL systems and our Typhoon Oil Pipeline, both acquired in November 2002, contributed approximately $5.5 million to the increase. Partially offsetting this increase was a $1.7 million decline in margin for our Texas NGL fractionation assets due to lower volumes resulting from poor processing economics.

Operating expenses excluding depreciation, depletion, and amortization for the quarter ended September 30, 2003, were $5.0 million higher than the same period in 2002 primarily due to increased operating expenses related to our November 2002 acquisition of the Typhoon Oil Pipeline and the Texas NGL systems.

Other income for the quarter ended September 30, 2003, was $1.4 million lower than the same period in 2002 due to a decrease in cash distributions from our unconsolidated affiliate Poseidon. Poseidon experienced lower earnings due to reduced volumes, primarily attributable to natural production declines on some of the older deepwater fields to which it connects, as well as production downtime at several new fields.

Nine Months Ended September 30, 2003 Compared With Nine Months Ended September 30, 2002

For the nine months ended September 30, 2003, margin was $12.6 million higher than the same period in 2002. Our acquisition, in November 2002, of the Texas NGL systems and Typhoon Oil Pipeline contributed approximately $16.6 million to the increase. Partially offsetting this increase was a $3.6 million decrease for our Texas NGL fractionation assets due to lower volumes resulting from poor processing economics.

Operating expenses excluding depreciation, depletion, and amortization for the nine months ended September 30, 2003 were $9.9 million higher than the same period in 2002, primarily due to increased operating expenses related to our November 2002 acquisition of the Typhoon Oil Pipeline and the Texas NGL systems.

Other income for the nine months ended September 30, 2003, was $3.7 million lower than the same period in 2002 due to a decrease in cash distributions from our unconsolidated affiliate Poseidon. Poseidon experienced lower earnings due to natural production declines on some of the older deepwater fields, as well as production downtime at several new fields.

Natural Gas Storage

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands, except for volumes)			
Natural gas storage revenue	$10,252	$ 8,599	$33,007	$18,454
Cost of natural gas and other products	339	—	(1,090)	—
Natural gas storage margin	10,591	8,599	31,917	18,454
Operating expenses excluding depreciation, depletion, and amortization	(3,074)	(3,144)	(9,331)	(8,199)
Other income	4	—	4	—
Cash distributions from unconsolidated affiliates in excess of (less than) earnings[1]	(882)	—	(882)	—
Minority interest	879	—	879	—
EBITDA	$ 7,518	$ 5,455	$22,587	$10,255
Firm storage				
Average working gas capacity available (Bcf)	13.5	13.5	13.5	9.3
Average firm subscription (Bcf)	12.8	11.5	12.7	8.7
Commodity volumes[2] (Bcf)	2.4	1.6	4.0	2.9
Interruptible storage				
Contracted volumes (Bcf)	0.4	0.2	0.3	0.3
Commodity volumes[2] (Bcf)	0.5	0.9	0.6	0.4

(1) Cash distributions from unconsolidated affiliates, in excess of (less than) earnings is related to the sale of our interest in Copper Eagle to El Paso Natural Gas Company.

(2) Combined injections and withdrawals volumes.

At our Petal and Hattiesburg storage facilities, we collect fixed and variable fees for providing storage services, some of which is generated from customers with cashout provisions, calculated by reference to a tariff-based index. We incur expenses, which are reflected as cost of natural gas, as we maintain these volumetric imbalance receivables and payables, all of which are valued at current gas prices. For these reasons, we believe that gross margin (revenue less cost of natural gas and other products) provides a more accurate and meaningful basis for analyzing operating results for this segment. Cost of natural gas reflects the initial loss of base gas in our storage facilities or the encroachment on our base gas by third parties at the market price in the period of the loss or encroachment and the monthly revaluation of these amounts based on the monthly change in natural gas prices.

Third Quarter Ended September 30, 2003 Compared with Third Quarter Ended September 30, 2002

For the quarter ended September 30, 2003, margin was $2.0 million higher than the same period in 2002 primarily due to an increase in subscribed firm storage capacity attributable to the expansion of the Petal storage facility. Although the expansion was completed in June 2002, we did not receive 100 percent of expected demand payments until September 2002, when the last pipeline interconnect was placed in service.

Nine Months Ended September 30, 2003 Compared with Nine Months Ended September 30, 2002

For the nine months ended September 30, 2003, margin was $13.5 million higher than the same period in 2002 primarily due to an increase in subscribed firm storage capacity attributable to the expansion of the Petal storage facility, which was completed in June 2002, and our acquisition of the Wilson storage facility lease in April 2002. In addition, margin attributable to Wilson storage was up an additional $0.9 million due to new contracts, offset by a $1.1 million decline in firm contracts at our Hattiesburg storage facility.

Operating expenses excluding, depreciation, depletion, and amortization for the nine months ended September 30, 2003 were $1.1 million higher than the same period in 2002 primarily due to our acquisition of the Wilson storage facility lease in April 2002 and expansion of the Petal storage facility in June 2003. Operating costs of our original storage facilities have remained fairly consistent.

Platform Services

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In thousands, except for volumes)			
Platform services revenue from external customers	$5,185	$3,595	$15,668	$13,222
Platform services intersegment revenue	600	1,547	2,004	7,770
Operating expenses excluding depreciation, depletion, and amortization	(900)	(1,191)	(2,275)	(2,422)
Other income	—	115	—	114
Discontinued operations of Prince facilities	—	456	—	6,153
EBITDA	$4,885	$4,522	$15,397	$24,837
Natural gas platform volumes (Mdth/d)				
East Cameron 373 platform	107	119	110	134
Garden Banks 72 platform	6	12	17	13
Viosca Knoll 817 platform	5	9	5	9
Falcon Nest platform	184	—	135	—
Total natural gas platform volumes	302	140	267	156
Oil platform volumes (Bbl/d)				
East Cameron 373 platform	1,111	1,576	952	1,764
Garden Banks 72 platform	1,032	1,036	1,055	1,131
Viosca Knoll 817 platform	2,141	2,170	2,051	2,106
Falcon Nest platform	699	—	515	—
Total oil platform volumes	4,983	4,782	4,573	5,001

Our platform services segment generally receives revenue through demand fees (regular payments made by customers using our platform services regardless of volumes) and commodity charges (volume-based payments made by customers). Contracts for platform services often include both demand charges and commodity charges, but demand charges generally expire after a fixed period of time.

Third Quarter Ended September 30, 2003 Compared with Third Quarter Ended September 30, 2002

For the quarter ended September 30, 2003, revenues were $1.6 million higher than in the same period in 2002, of which $3.1 million is attributable to the Falcon Nest fixed leg platform that went into operation in March 2003. This increase is partially offset by lower revenues of $1.5 million from East Cameron 373 resulting from lower demand fees. Intersegment revenues were $0.9 million lower due to a decline in demand fees on the Garden Banks 72 platform associated with contracts with one of our wholly owned subsidiaries, which terms expired in December 2002.

Nine Months Ended September 30, 2003 Compared with Nine Months Ended September 30, 2002

For the nine months ended September 30, 2003, revenues from external customers were $2.4 million higher than in the same period in 2002, of which $6.9 million is attributable to the Falcon Nest fixed leg platform that went into operation in March 2003. Partially offsetting this increase are lower revenues of $4.1 million from East Cameron 373 resulting from one time billing adjustments in 2002 for fixed monthly platform access fees, a gas dehydration fee, decreased demand fees and lower production. Intersegment revenues were $5.6 million lower due to a decline in demand fees on the Viosca Knoll 817 and Garden Banks 72 platforms associated with contracts with one of our wholly owned subsidiaries, which terms expired in June 2002 and December 2002.

Other, Net

EBITDA related to non-segment activity for the quarter and nine months ended September 30, 2003, was $0.4 and $4.4 million higher than the same periods in 2002 primarily due to lower demand fee expense as a result of the expiration of the fixed fee portion of the Viosca Knoll 817 contract in June 2002 and the Garden Banks 72 contract in December 2002 and higher oil and natural gas prices in 2003. Partially offsetting these increases were lower production from the Garden Banks 117 and Viosca Knoll 817 fields and higher operating expenses associated with an increase in professional fees, including legal, accounting and consulting services.

In connection with the sale of our Gulf of Mexico assets in January 2001, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and $2 million in the first quarter of 2004. These payments from El Paso Corporation have been reflected in EBITDA related to non-segment activities and will terminate in the first quarter of 2004.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization for the quarter and nine months ended September 30, 2003, was $5.9 million and $23.8 million higher than the same periods in 2002. This increase is primarily due to our November 2002 acquisition of the San Juan assets and our April 2002 acquisition of the EPN Holding assets. Further contributing to the increase was the completion of the Falcon Nest platform in March 2003 and the Petal expansion in June 2002. We have several capital projects in process, and as additional assets from our completed projects are placed into service, depreciation, depletion and amortization expense will increase. The amount of additional expense will be a function of the final cost of each project and each project's expected useful life.

Interest and Debt Expense

Interest and debt expense, net of capitalized interest, for the quarter and nine months ended September 30, 2003, was approximately $11.1 million and $44.2 million higher than the same periods in 2002. The increase for the nine month period is primarily due to a higher weighted average interest rate (4.0% compared to 3.65% for the nine months ended September 30, 2002) on our revolving credit facility and interest incurred on the following indebtedness:

- our $230 million 8½% senior subordinated notes, issued in May 2002 and used to repay a portion of the GulfTerra Holding term credit facility;
- our $160 million senior secured term loan, borrowed in October 2002;
- our $200 million 10⅝% senior subordinated notes and our $237.5 million senior secured acquisition term loan, both closed in November 2002 in connection with our acquisition of the San Juan assets;
- our $300 million 8½% senior subordinated notes, issued in March 2003 and used to repay our $237.5 million senior secured acquisition term loan; and
- our $250 million 6¼% senior notes, issued in July 2003 and used to repay our GulfTerra Holding term credit facility and temporarily reduce indebtedness outstanding under our revolving credit facility.

The increase in our interest expense for the nine months ended September 30, 2003 was partially offset by lower average balances outstanding under our revolving credit facility and the GulfTerra Holding term credit facility during 2003 due to repayments from net proceeds of our 2003 debt and equity offerings.

The increase in interest expense for the quarter ended September 30, 2003 compared to the same period in 2002 is attributable to the interest incurred on the additional indebtedness discussed above, excluding our \$230 million 8½% senior subordinated notes issued in May 2002, partially offset by lower weighted average interest rates and lower outstanding balances on our revolving credit facility and the GulfTerra Holding term credit facility, which we repaid in July 2003.

Capitalized interest for the quarter and nine months ended September 30, 2003 was \$2.5 million and \$7.0 million, representing increases of \$1.7 million and \$2.6 million over the comparable prior periods. The increases are the result of an increase in average construction work-in-process in 2003 as a result of our construction projects.

Losses Due to Write-off of Debt Issuance Costs

In March 2003, we repaid our \$237.5 million senior secured term loan which was due in May 2004 and recognized a loss of \$3.8 million related to the write-off of the unamortized debt issuance costs related to this loan.

In July 2003, we repaid our \$160 million GTM Holding term credit facility that was scheduled to mature in April 2005 and recognized a loss of \$1.2 million related to the write-off of the unamortized debt issuance costs associated with this facility.

Commitments and Contingencies

See Item 1, Financial Information, Note 7, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Information, Note 13, which is incorporated by reference.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements. These statements are subject to risks and uncertainties. Forward-looking statements include information concerning possible or assumed future results of operations. These statements may relate to information or assumptions about:

- earnings per unit;
- capital and other expenditures;
- cash distributions;
- financing plans;
- capital structure;
- liquidity and cash flow;
- pending legal proceedings and claims, including environmental matters;
- future economic performance;
- operating income;
- cost savings;

• management's plans; and

• goals and objectives for future operations.

Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our Annual Report on Form 10-K for the year ended December 31, 2002, and our other filings with the Securities and Exchange Commission. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and made in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we express an expectation or belief as to future results, such expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. These statements relate to analyses and other information which are based on forecasts of future results and estimates of amounts not yet determinable. These statements also relate to our future prospects, developments and business strategies. These forward-looking statements are identified by their use of terms and phrases such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project," "will," and similar terms and phrases, including references to assumptions. These forward-looking statements involve risks and uncertainties that may cause our actual future activities and results of operations to be materially different from those suggested or described.

These risks may also be specifically described in our Current Reports on Form 8-K and other documents filed with the Securities and Exchange Commission. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information or otherwise. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those expected, estimated or projected.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, our quantitative and qualitative disclosures about market risks reported in our Annual Report on Form 10-K for the year ended December 31, 2002, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of $3.525 per MMBtu and pay a floating price based on the San Juan index. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative under mark-to-market accounting since it did not qualify for hedge accounting under SFAS No. 133. Through the acquisition date in 2002, we recognized a $0.4 million net gain, ($1.0 million loss in the third quarter of 2002 and $1.4 million gain in the fourth quarter of 2002), in the margin of our natural gas pipelines and plants segment. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under SFAS No. 133. In February and August 2003, we entered into additional derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. We are accounting for these derivatives as cash flow hedges under SFAS No. 133. As of September 30, 2003, the fair value of all of our San Juan gathering cash flow hedges was a liability of $2.4 million, as the market price at that date was higher than the hedge price of $4.23. For the nine months ended September 30, 2003, we reclassified $8.4 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue resulting in a reduction to earnings. No ineffectiveness exists in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

In connection with our GulfTerra Intrastate Alabama operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We have entered into cash flow hedges in 2002 and 2003 to offset the risk of increasing natural gas prices for our purchases to satisfy these sales contracts. As of September 30, 2003, the fair value of these cash flow hedges was a liability of $11 thousand, as the market price at that date was lower than the hedge price of $5.20. For the nine months ended September 30, 2003, we reclassified $223 thousand of unrealized accumulated gain related to these derivatives from accumulated other comprehensive income to earnings as a reduction of cost of natural gas. No ineffectiveness existed in this hedging relationship because all purchase and sale prices were based on the same index and volumes as the hedge transaction.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable portion of its LIBOR based interest rate on $75 million of its $185 million variable rate revolving credit facility at 3.49% over the life of the swap. Prior to April 2003, under its credit facility, Poseidon paid an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced to 1.25% resulting in an effective fixed interest rate of 4.74% on the hedged notional amount. As of September 30, 2003, the fair value of its interest rate swap was a liability of $0.5 million, as the market interest rate was lower than the hedge rate of 4.99%, resulting in accumulated other comprehensive loss of $0.5 million. We included our 36 percent share of this liability of $0.2 million as a reduction of our investment in Poseidon and as loss in accumulated other comprehensive income which we estimate will be reclassified to earnings proportionately over the next three months. Additionally, we have recognized as a reduction of income our 36 percent share of Poseidon's realized loss of $1.3 million for the nine months ended September 30, 2003, or $0.5 million, through our earnings from unconsolidated affiliates.

We estimate the entire $3.0 million of unrealized losses included in accumulated other comprehensive income at September 30, 2003, will be classified from accumulated other comprehensive income as a reduction to earnings over the next 15 months and approximately $2.9 million will be reclassed as a reduction to earnings over the next twelve months. When our derivative financial instruments are settled, the related amount in accumulated other comprehensive income is recorded in the income statement in operating revenues, cost of natural gas and others products, or interest and debt expense, depending on the item being hedged. The effect of reclassifying these amounts to the income statement line items is recording our earnings for the period at the "hedged price" under the derivative financial instruments.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we pay the counterparty a LIBOR based interest rate plus a spread of 4.20% and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under FAS No. 133. As of September 30, 2003, the fair value of the interest rate swap was a liability, included in non-current liabilities, of approximately $2.2 million. The fair value of the hedged debt decreased by the same amount.

Item 4. Controls and Procedures

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls over financial reporting (Internal Controls) as of the end of the period covered by this Quarterly Report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are properly authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. Our management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our Disclosure Controls and Internal Controls are designed to provide such reasonable assurances of achieving our desired control objectives, and our principal executive officer and principal financial officer have concluded that our Disclosure Controls and Internal Controls are effective in achieving that level of reasonable assurance.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in GulfTerra Energy Partners' Internal Controls, or whether GulfTerra Energy Partners had identified any acts of fraud involving personnel who have a significant role in GulfTerra Energy Partners' Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Quarterly Report. The principal executive officer and principal financial officer note that there have not been any significant changes in Internal Controls or in other factors that could significantly affect Internal Controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that the Disclosure Controls are effective to ensure that material information relating to GulfTerra Energy Partners and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, on a timely basis.

Officer Certifications. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as Exhibits to this Quarterly Report.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Financial Information, Note 7, which is incorporated herein by reference.

Item 2. Changes in Securities and Use of Proceeds

We have amended the portion of our partnership agreement relating to our Series F units. See Part I, Item 2, Management's Discussion and Analysis, "General Partner Relationship" and "Liquidity and Capital Resources" for discussions of how these changes affect our common units, which is incorporated herein by reference.

In October 2, 2003, in connection with the investment by Goldman, Sachs & Co., a wholly owned subsidiary of Goldman Sachs Group Inc., of a 9.9 percent membership interest in our generally partner, Goldman Sachs purchased 3,000,000 of our common units from us for $112 million in a transaction exempt from registration pursuant to Section 4(2) of the Securities Act of 1933, as amended, as a transaction not involving any public offering.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by a "*"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" represent a management contract or compensatory plan or arrangement.

Exhibit Number		Description
3.A	—	Amended and Restated Certificate of Limited Partnership dated February 14, 2002; Amendment dated April 30, 2003 (Exhibit 3.A.1 to our 2003 First Quarter Form 10-Q); Amendment 2 dated July 25, 2003 (Exhibit 3.A.1 to our 2003 Second Quarter Form 10-Q).
*3.A.1	—	Conformed Certificate of Limited Partnership.
3.B	—	Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Current Report on Form 8-K dated March 6, 2001); First Amendment dated November 27, 2002 (Exhibit 3.B.1 to our Current Report on Form 8-K dated December 11, 2002); Second Amendment dated May 5, 2003 (Exhibit 3.B.2 to our Current Report on Form 8-K dated May 13, 2003); Third Amendment dated May 16, 2003 (Exhibit 3.B.3 to our Current Report on 8-K dated May 16, 2003); Fourth Amendment dated July 23, 2003 (Exhibit 3.B.1 to our 2003 Second Quarter Form 10-Q); Fifth Amendment dated August 21, 2003 (Exhibit 3.B.1 to our Current Report on Form 8-K dated October 10, 2003).

Exhibit Number	Description
3.B.1	— Conformed Partnership Agreement (Exhibit 3.B.2 to our Current Report on Form 8-K dated October 10, 2003).
4.D	— Indenture dated as of May 27, 1999 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4, filed on June 24, 1999, File Nos. 333-81143 through 333-81143-17); First Supplemental Indenture dated as of June 30, 1999 (Exhibit 4.2 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999 File Nos. 333-81143 through 333-81143-17); Second Supplemental Indenture dated as of July 27, 1999 (Exhibit 4.3 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999, File Nos. 333-81143 through 333-81143-17); Third Supplemental Indenture dated as of March 21, 2000, to the Indenture dated as of May 27, 1999, (Exhibit 4.7.1 to our 2000 Second Quarter Form 10-Q); Fourth Supplemental Indenture dated as of July 11, 2000 (Exhibit 4.2.1 to our 2001 Third Quarter Form 10-Q); Fifth Supplemental Indenture dated as of August 30, 2000 (Exhibit 4.2.2 to our 2001 Third Quarter Form 10-Q); Sixth Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.1 to our 2002 First Quarter Form 10-Q); Seventh Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.2 to our 2002 First Quarter Form 10-Q); Eighth Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.D.3 to our 2002 Third Quarter Form 10-Q); Ninth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.D.1 to our Current Report on Form 8-K dated March 19, 2003); Tenth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.D.2 to our Current Report on Form 8-K dated March 19, 2003); Eleventh Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.D.1 to our 2003 Second Quarter Form 10-Q).
4.E	— Indenture dated as of May 17, 2001 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, The Subsidiary Guarantors named therein and the Chase Manhattan Bank, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.1 to our 2002 First Quarter Form 10-Q), Second Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.2 to our 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.E.3 to our 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.E.1 to our Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.E.2 to our Current Report on Form 8-K dated March 19, 2003); Sixth Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.E.1 to our 2003 Second Quarter Form 10-Q).
4.G	— Registration Rights Agreement by and between El Paso Corporation and GulfTerra Energy Partners, L.P. dated as of November 27, 2002 (Exhibit 4.G to our Current Report on Form 8-K dated December 11, 2002).
4.I	— Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (Exhibit 4.I to our Current Report on Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.I.1 to our Current Report on Form 8-K dated March 19, 2003). Second Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.I.1 to our 2003 Second Quarter Form 10-Q).

Exhibit Number	Description
4.J	— A/B Exchange Registration Rights Agreement by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors party thereto, J.P. Morgan Securities, Inc., Goldman Sachs & Co., UBS Warburg LLC and Wachovia Securities, Inc. dated as of March 24, 2003 (Exhibit 4.J to our Quarterly Report on Form 10-Q, dated May 15, 2003).
4.K	— Indenture dated as of March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee dated as of March 24, 2003 (Exhibit 4.K to our Quarterly Report on Form 10-Q dated May 15, 2003), First Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.K.1 to our 2003 Second Quarter Form 10-Q).
4.L	— Indenture dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.L to our 2003 Second Quarter Form 10-Q).
4.M	— A/B Exchange Registration Rights Agreement dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein, J.P. Morgan Securities Inc., Banc One Capital Markets, Inc., BNP Paribas Securities Corp., Credit Lyonnais Securities (USA) Inc., Credit Suisse First Boston LLC, Fortis Investment Services LLC, The Royal Bank of Scotland plc, Scotia Capital (USA) Inc., SunTrust Capital Markets, Inc. and Wachovia Securities, LLC (Exhibit 4.M to our 2003 Second Quarter Form 10-Q).
10.A	— General and Administrative Services Agreement dated May 5, 2003 by and among DeepTech International Inc., GulfTerra Energy Company, L.L.C. and El Paso Field Services, L.P. (Exhibit 10.A to our Current Report on Form 8-K dated May 14, 2003).
10.L+	— 1998 Common Unit Plan for Non-Employee Directors (formerly 1998 Unit Option Plan for Non-Employee Directors) Amended and Restated effective as of April 18, 2001 (Exhibit 10.1 to our 2001 Second Quarter Form 10-Q); Amendment No. 1 dated as of May 15, 2003 (Exhibit 10.L.1 to our 2003 Second Quarter Form 10-Q).
10.M+	— 1998 Omnibus Compensation Plan, Amended and Restated, effective as of January 1, 1999 (Exhibit 10.9 to our 1998 Form 10-K); Amendment No. 1 dated as of December 1, 1999 (Exhibit 10.8.1 to our 2000 Second Quarter Form 10-Q); Amendment No. 2 dated as of May 15, 2003 (Exhibit 10.M.1 to our 2003 Second Quarter Form 10-Q).
10.N	— Seventh Amended and Restated Credit Agreement dated September 26, 2003 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, as co-borrowers, JPMorgan Chase Bank, as administrative agent, and the other lenders party thereto (Exhibit 10.B to our Current Report on Form 8-K dated October 10, 2003).
*10.O	— Participation Agreement and Assignment relating to Cameron Highway Oil Pipeline Company dated as of July 10, 2003 among Valero Energy Corporation, GulfTerra Energy Partners, L.P., Cameron Highway Pipeline I, L.P. and Manta Ray Gathering Company, L.L.C.
10.T	— Purchase and Sale Agreement by and between GulfTerra Energy Partners, L.P. and Goldman Sachs & Co. dated as of October 2, 2003 (Exhibit 10.T to our Current Report on Form 8-K dated October 10, 2003).

Exhibit Number	Description
10.U	— Exchange and Registration Rights Agreement by and among GulfTerra Energy Company, L.L.C., GulfTerra Energy Partners, L.P. and Goldman Sachs & Co. dated as of October 2, 2003 (Exhibit 10.U to our Current Report on Form 8-K dated October 10, 2003).
10.V	— Incentive Distribution Reduction Agreement by and between GulfTerra Energy Company, L.L.C. and GulfTerra Energy Partners, L.P. dated as of October 1, 2003 (Exhibit 10.V to our Current Report on Form 8-K dated October 10, 2003).
10.W	— Redemption and Resolution Agreement by and among El Paso Corporation, GulfTerra Energy Partners, L.P. and El Paso New Chaco Holding, L.P. dated as of October 2, 2003 (Exhibit 10.W to our Current Report on Form 8-K dated October 10, 2003).
*31.A	— Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	— Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.A	— Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.B	— Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

We hereby undertake, pursuant to Regulation S-K Items 601(b), paragraph (4)(iii), to furnish to the U.S. Securities and Exchange Commission, upon request, all constituent instruments defining the rights of holders of our long-term debt not filed herewith for the reason that the total amount of securities authorized under any such instruments does not exceed 10 percent of our total consolidated assets.

(b) Reports on Form 8-K

We filed a current report on Form 8-K dated August 18, 2003 to file an unaudited balance sheet of GulfTerra Energy Company L.L.C., our general partner, as of June 30, 2003.

We filed a current report on Form 8-K dated August 21, 2003 to file exhibits to the Registration Statement on Form S-3 (Registration No. 333-81772), relating to the issuance of 507,278 common units.

We filed a current report on Form 8-K dated August 26, 2003 to file exhibits to the Registration Statement on Form S-3 (Registration No. 333-81772) relating to the issuance and sale of up to 8,329,679 common units representing limited partnership interests in us from time to time in connection with the conversion of our Series F convertible units.

We filed a current report on Form 8-K dated October 10, 2003 to file (a) the amendment to our partnership agreement, (b) our amended credit agreement, (c) material agreements relating to Goldman Sachs' investment in us and our general partner and (d) a consent from independent petroleum engineers.

We also furnished information to the SEC on Current Reports on Form 8-K under Item 9 and Item 12. Current Reports on Form 8-K under Item 9 and Item 12 are not considered to be "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 and are not subject to the liabilities of that section.

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.

GULFTERRA ENERGY PARTNERS, L.P.

Date: November 3, 2003

By: /s/ KEITH B. FORMAN

Keith B. Forman
Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: November 3, 2003

By: /s/ KATHY A. WELCH

Kathy A. Welch
Vice President and Controller
(Principal Accounting Officer)