ENTERPRISE PRODUCTS PARTNERS L P
Form 8-K
April 20, 2004

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

FORM 8-K

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

Date of report (Date of earliest event reported): December 15, 2003

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact Name of Registrant as Specified in its Charter)

DELAWARE	1-14323	76-0568219
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

2727 NORTH LOOP WEST, HOUSTON, TEXAS 77008
(Address of Principal Executive Offices) (Zip Code)

(713) 880-6500
(Registrant's Telephone Number, including Area Code)

EXPLANATORY NOTE

On December 15, 2003, Enterprise Products Partners L.P. ("Enterprise") and certain of its affiliates, El Paso Corporation ("El Paso") and certain of its affiliates, and GulfTerra Energy Partners, L.P. ("GulfTerra") and certain of its affiliates entered into a series of definitive agreements pursuant to which Enterprise and GulfTerra will merge. The purpose of this Current Report on Form 8-K is to file (1) the consolidated financial statements of GulfTerra as of December 31, 2003 and 2002 and for the three year period ended December 31, 2003, and (2) the financial statements of Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate of GulfTerra, as of December 31, 2003 and 2002 and for the three year period ended December 31, 2003, pursuant to the requirements of S-X Rule 3-05(a) and (b), in connection with Enterprise's proposed merger with GulfTerra. Enterprise is filing these financial statements with this report so that they will be incorporated by reference in its currently effective registration statements.

ITEM 7. FINANCIAL STATEMENTS AND EXHIBITS.

(a) Financial statements of businesses acquired.

1. Consolidated Financial Statements of GulfTerra Energy Partners, L.P. as of December 31, 2003 and 2002 and for the three year period ended December 31, 2003 and independent auditors' report.

2. Financial Statements of Poseidon Oil Pipeline Company, L.L.C. as of December 31, 2003 and 2002 and for the three year period ended December 31, 2003 and independent auditors' report.

REPORT OF INDEPENDENT AUDITORS

To the Unitholders of GulfTerra Energy Partners, L.P.
and the Board of Directors and Stockholders of
GulfTerra Energy Company, L.L.C., as General Partner:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income and changes in accumulated other comprehensive income (loss), partners' capital and cash flows present fairly, in all material respects, the financial position of GulfTerra Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Partnership has entered into a definitive agreement to merge with Enterprise Products Partners L.P.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for asset retirement obligations and its reporting for gains or losses resulting from the extinguishment of debt effective January 1, 2003.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for the impairment or disposal of long lived assets effective January 1, 2002.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 12, 2004

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Operating revenues			
Natural gas pipelines and plants			
Natural gas sales	$ 171,738	$ 85,001	$ 59,701
NGL sales	121,167	32,978	--
Gathering and transportation	388,777	194,336	33,849
Processing	52,988	45,266	7,133
	734,670	357,581	100,683
Oil and NGL logistics			
Oil sales	2,231	108	--
Oil transportation	26,769	8,364	7,082
Fractionation	22,034	26,356	25,245
NGL storage	2,816	2,817	--
	53,850	37,645	32,327
Platform services	20,861	16,672	15,385
Natural gas storage	44,297	28,602	19,373
Other -- oil and natural gas production	17,811	16,890	25,638
	871,489	457,390	193,406
Operating expenses			
Cost of natural gas and other products	287,157	108,819	51,542
Operation and maintenance	189,702	115,162	33,279
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	--	--	3,921
(Gain) loss on sale of long-lived assets	(18,679)	473	11,367
	557,026	296,580	134,887
Operating income	314,463	160,810	58,519
Earnings from unconsolidated affiliates	11,373	13,639	8,449
Minority interest income (expense)	(917)	60	(100)
Other income	1,206	1,537	28,726
Interest and debt expense	127,830	81,060	41,542
Loss due to early redemptions of debt	36,846	2,434	--
Income from continuing operations	161,449	92,552	54,052
Income from discontinued operations	--	5,136	1,097
Cumulative effect of accounting change	1,690	--	--
Net income	$ 163,139	$ 97,688	$ 55,149

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME -- (CONTINUED)
(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Income allocation			
Series B unitholders	$11,792	$14,688	$17,228
General partner			
Income from continuing operations	$69,414	$42,082	$24,650
Income from discontinued operations	--	51	11
Cumulative effect of accounting change	17	--	--
	$69,431	$42,133	$24,661
Common unitholders			
Income from continuing operations	$65,155	$34,275	$12,174
Income from discontinued operations	--	5,085	1,086
Cumulative effect of accounting change	1,340	--	--
	$66,495	$39,360	$13,260
Series C unitholders			
Income from continuing operations	$15,088	$ 1,507	$ --
Cumulative effect of accounting change	333	--	--
	$15,421	$ 1,507	$ --
Basic earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	--	0.12	0.03
Cumulative effect of accounting change	0.03	--	--
Net income	$ 1.33	$ 0.92	$ 0.38
Diluted earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	--	0.12	0.03
Cumulative effect of accounting change	0.02	--	--
Net income	$ 1.32	$ 0.92	$ 0.38
Basic weighted average number of common units outstanding	49,953	42,814	34,376
Diluted weighted average number of common units outstanding	50,231	42,814	34,376

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS)

	DECEMBER 31, 2003	DECEMBER 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 30,425	$ 36,099
Accounts receivable, net		
Trade	43,203	90,379
Unbilled trade	63,067	49,140
Affiliates	47,965	83,826
Affiliated note receivable	3,768	--
Other current assets	20,595	3,451
Total current assets	209,023	262,895
Property, plant and equipment, net	2,894,492	2,724,938
Intangible assets	3,401	3,970
Investments in unconsolidated affiliates	175,747	95,951
Other noncurrent assets	38,917	43,142
Total assets	$3,321,580	$3,130,896
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	$ 113,820	$ 120,140
Affiliates	38,870	86,144
Accrued gas purchase costs	15,443	6,584
Accrued interest	11,199	15,028
Current maturities of senior secured term loan	3,000	5,000
Other current liabilities	27,035	21,195
Total current liabilities	209,367	254,091
Revolving credit facility	382,000	491,000
Senior secured term loans, less current maturities	297,000	552,500
Long-term debt	1,129,807	857,786
Other noncurrent liabilities	49,043	23,725
Total liabilities	2,067,217	2,179,102
Commitments and contingencies		
Minority interest	1,777	1,942
Partners' capital		
Limited partners		
Series B preference units; 125,392 units in 2002 issued and outstanding	--	157,584
Common units; 58,404,649 and 44,030,314 units in 2003 and 2002 issued and outstanding	898,072	433,150
Series C units; 10,937,500 units in 2003 and 2002 issued and outstanding	341,350	350,565
General partner	13,164	8,553

Total partners' capital	1,252,586	949,852
Total liabilities and partners' capital	$3,321,580	$3,130,896

See accompanying notes.

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Cash flows from operating activities			
Net income	$ 163,139	$ 97,688	$ 55,149
Less cumulative effect of accounting change	1,690	--	--
Less income from discontinued operations	--	5,136	1,097
Income from continuing operations	161,449	92,552	54,052
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	--	--	3,921
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	(11,373)	(13,639)	(8,449
Distributions from unconsolidated affiliates	12,140	17,804	35,062
(Gain) loss on sale of long-lived assets	(18,679)	473	11,367
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	12,544	2,434	--
Amortization of debt issuance costs	7,498	4,443	3,608
Other noncash items	3,445	4,429	544
Working capital changes, net of acquisitions and non-cash transactions			
Accounts receivable	66,441	(167,536)	(41,037
Other current assets	(9,762)	(12,612)	125
Other noncurrent assets	(1,540)	467	(10,379
Accounts payable	(45,829)	143,553	(672
Accrued gas purchase costs	8,859	4,223	(2,776
Accrued interest	(3,829)	9,330	3,574
Other current liabilities	(8,928)	13,086	(235
Other noncurrent liabilities	(3,114)	(377)	(1,067
Net cash provided by continuing operations	268,168	170,756	82,416
Net cash provided by discontinued operations	--	5,244	4,968
Net cash provided by operating activities	268,168	176,000	87,384
Cash flows from investing activities			
Development expenditures for oil and natural gas properties	(145)	(1,682)	(2,018

Additions to property, plant and equipment................	(332,019)	(202,541)	(508,347
Proceeds from the sale and retirement of assets...........	77,911	5,460	109,126
Additions to investments in unconsolidated affiliates.....	(35,536)	(38,275)	(1,487
Proceeds from the sale of investments in unconsolidated affiliates..	1,355	--	--
Repayments on note receivable............................	1,238	--	--
Cash paid for acquisitions, net of cash acquired..........	(20)	(1,164,856)	(28,414
Net cash used in investing activities of continuing operations..	(287,216)	(1,401,894)	(431,140
Net cash provided by (used in) investing activities of discontinued operations..............................	--	186,477	(68,560
Net cash used in investing activities............	(287,216)	(1,215,417)	(499,700

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS -- (CONTINUED)
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Cash flows from financing activities			
Net proceeds from revolving credit facility...............	533,564	366,219	559,994
Repayments of revolving credit facility..................	(647,000)	(177,000)	(581,000
Net proceeds from GulfTerra Holding term credit facility..	--	530,136	--
Repayment of GulfTerra Holding term credit facility.......	--	(375,000)	--
Repayment of GulfTerra Holding term loan.................	(160,000)	--	--
Net proceeds from senior secured acquisition term loan....	(23)	233,236	--
Repayment of senior secured acquisition term loan.........	(237,500)	--	--
Net proceeds from senior secured term loan...............	299,512	156,530	--
Repayment of senior secured term loan....................	(160,000)	--	--
Net proceeds from issuance of long-term debt.............	537,426	423,528	243,032
Repayments of long-term debt.............................	(269,401)	--	--
Repayment of Argo term loan..............................	--	(95,000)	--
Distributions to minority interests......................	(1,242)	--	--
Net proceeds from issuance of common units...............	509,010	150,159	286,699
Redemption of Series B preference units..................	(155,673)	--	(50,000
Contributions from general partner.......................	3,098	4,095	2,843
Distributions to partners................................	(238,397)	(154,468)	(106,409
Net cash provided by financing activities of continuing operations..	13,374	1,062,435	355,159
Net cash provided by (used in) financing activities of discontinued operations..............................	--	(3)	49,960
Net cash provided by financing activities.........	13,374	1,062,432	405,119
Increase (decrease) in cash and cash equivalents..........	(5,674)	23,015	(7,197
Cash and cash equivalents at beginning of year............	36,099	13,084	20,281

Cash and cash equivalents at end of year....................	$ 30,425	$ 36,099	$ 13,084
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See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(IN THOUSANDS)

	SERIES B PREFERENCE UNITS(1)	SERIES B PREFERENCE UNITHOLDERS	SERIES C UNITS(2)	SERIES C UNITHOLDERS	COMMON UNITS	COMMON UNITHOLD
Partners' capital at January 1, 2001.........	170	$ 175,668	--	$ --	31,550	$ 132,8
Net income(4).............	--	17,228	--	--	--	13,2
Other comprehensive loss....................	--	--	--	--	--	(1,2
Issuance of common units..................	--	--	--	--	8,189	286,6
Issuance of unit options.................	--	--			--	2,1
Redemption of Series B preference units........	(45)	(50,000)	--	--	--	
General partner contribution related to the issuance of common units..................	--	--	--	--	--	
Cash distributions........	--	--	--	--	--	(80,9
	----	---------	------	--------	------	-------
Partners' capital at December 31, 2001.......	125	$ 142,896	--	$ --	39,739	$ 352,7
Net income(4).............	--	14,688	--	1,507	--	39,3
Issuance of Series C units..................	--	--	10,938	350,000	--	
Other comprehensive loss....................	--	--	--	(942)	--	(3,3
Issuance of common units..................	--	--	--	--	4,291	156,0
Issuance of unit options.................	--	--	--	--	--	
General partner contribution related to the issuance of Series C units and common units..................	--	--	--	--	--	
Cash distributions........	--	--	--	--	--	(111,7
	----	---------	------	--------	------	-------
Partners' capital at December 31, 2002.......	125	$ 157,584	10,938	$350,565	44,030	$ 433,1
Net income(4).............	--	11,792	--	15,421		66,4
Other comprehensive loss....................	--		--	(467)	--	(2,8
Issuance of common units..................	--	--	--	--	14,056	494,8

Issuance of Series F units..................	--	--	--	--	--	4,1
Redemption of unit options................	--	--	--	--	319	10,0
Redemption of Series B preference units........	(125)	(169,376)	--	1,919	--	9,6
Issuance of unit options and restricted units....						1,6
General partner contribution related to the issuance of common units..................	--	--	--	--	--	
Receipt of communication assets.................	--	--	--	4,100	--	18,9
Cash distributions........	--	--	--	(30,188)	--	(138,0
Partners' capital at December 31, 2003.......	--	$ --	10,938	$341,350	58,405	$ 898,0

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(1) In October 2003, we redeemed all of our remaining outstanding Series B preference units for $156 million.

(2) We issued 10,937,500 of our Series C units to El Paso Corporation for a value of $350 million in connection with our acquisition of the San Juan assets. A discussion of this new class of units is included in Note 8.

(3) GulfTerra Energy Company, L.L.C. is our sole general partner and is owned 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise Products Partners, L.P.

(4) Income allocation to our general partner includes both its incentive distributions and its one percent ownership interest.

See accompanying notes.

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)
(IN THOUSANDS)

COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Net income..	$163,139	$97,688	$55,149
Other comprehensive loss..............................	(3,405)	(4,350)	(1,272)
Total comprehensive income............................	$159,734	$93,338	$53,877

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Beginning balance	$ (5,622)	$(1,272)	$ --
Unrealized mark-to-market losses on cash flow hedges arising during period	(12,924)	(6,428)	(1,682)
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	10,018	1,579	410
Accumulated other comprehensive income (loss) from investment in unconsolidated affiliate	(499)	499	--
Ending balance	$ (9,027)	$(5,622)	$(1,272)

See accompanying notes.

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

We are a publicly held Delaware master limited partnership established in 1993 for the purpose of providing midstream energy services, including gathering, transportation, fractionation, storage and other related activities for producers of natural gas and oil, onshore and offshore in the Gulf of Mexico. As of December 31, 2003, we had 58,404,649 common units outstanding representing limited partner interests and 10,937,500 Series C units outstanding representing non-voting limited partner interests. On that date, the public owned 48,020,404 common units, or 82.2 percent of our outstanding common units, and El Paso Corporation, through its subsidiaries, owned 10,384,245 common units, or 17.8 percent of our outstanding common units, all of our Series C units and 50 percent of our general partner, which owns our one percent general partner interest.

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 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise, a publicly traded master limited partnership. El Paso Corporation (through its subsidiaries) owned 100 percent of our general partner until October 2003, when Goldman Sachs acquired a 9.9 percent interest in our general partner. In December 2003, El Paso Corporation reacquired Goldman Sachs' interest in our general partner and then sold a 50 percent interest in our general partner to a subsidiary of Enterprise.

On December 15, 2003, we, along with Enterprise and El Paso Corporation, announced that we had executed definitive agreements to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs with Enterprise being the continuing entity. The general partner of the combined partnership will be jointly owned by affiliates of El Paso Corporation and privately-held Enterprise Products Company, with each owning a 50-percent interest.

The combined partnership, which will retain the name Enterprise Products Partners L.P., will serve the largest producing basins of natural gas, crude oil and NGLs in the U.S., including the Gulf of Mexico, Rocky Mountains, San Juan Basin, Permian Basin, South Texas, East Texas, Mid-Continent and Louisiana Gulf Coast basins and, through connections with third-party pipelines, Canada's western sedimentary basin. The partnership will also serve the largest consuming regions for natural gas, crude oil and NGLs on the U.S. Gulf Coast.

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We account for investments in companies where we have the ability to exert significant influence over, but not control over operating and financial policies, using the equity method of accounting. Prior to May 2001, our general partner's approximate one percent non-managing interest in twelve of our subsidiaries represented the minority interest

in our consolidated financial statements. In May 2001, we purchased our general partner's one percent non-managing ownership interest in twelve of our subsidiaries for $8 million. As a result of this acquisition, all of our subsidiaries, but not our equity investees, are wholly-owned by us.

During part of 2003 and 2002, third parties had minority ownership interests in Matagorda Island Area Gathering System (MIAGS) and Arizona Gas, L.L.C. The assets, liabilities and operations of these entities are included in our consolidated financial statements and we account for the third party ownership interest as minority interest in our consolidated balance sheets and as minority interest income (expense) in our consolidated statements of income. In October 2003, we purchased the remaining 17 percent interest in MIAGS. As a result, we no longer recognize the third party ownership interest in MIAGS as minority interests in our consolidated balance sheets or consolidated statements of income.

Our consolidated financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or partners' capital. We have reflected the results of operations from our Prince assets disposition as discontinued operations for the years ended December 31, 2002 and 2001. See Note 2 for a further discussion of our Prince assets disposition.

Use of Estimates

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities that exist at the date of our financial statements. While we believe our estimates are appropriate, actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our HIOS interstate natural gas system and our Petal storage facility are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. Our businesses that are subject to the regulations and accounting requirements of FERC have followed the accounting requirements of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, which may differ from the accounting requirements of our non-regulated entities. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects.

Under the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations, which we adopted on January 1, 2003, the cost associated with the retirement of long-lived assets for regulated entities accounted for under SFAS No. 71 should be classified as a regulatory liability instead of as a component of property, plant and equipment. As a result, we reclassified $13.6 million from property, plant and equipment to a regulatory liability and at December 31, 2003, this balance is included in other noncurrent liabilities in our consolidated balance sheet. Prior to January 2003, this item was reflected in accumulated depreciation, depletion and amortization and the balance for this item at December 31, 2002, was $12.9 million.

When the accounting method followed is required by or allowed by the regulatory authority for rate-making purposes, the method conforms to the generally accepted accounting principle (GAAP) of matching costs with the revenues to which they apply.

Cash and Cash Equivalents

We consider short-term investments with little risk of change in value because of changes in interest rates and purchased with an original maturity of less than three months to be cash equivalents.

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. At December 31, 2003 and 2002, the allowance was $4.0 million and $2.5 million.

Natural Gas Imbalances

Natural gas imbalances result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. These imbalances are settled in kind through a tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure and are valued at prices representing the estimated value of these imbalances upon settlement. We estimate the value of our imbalances at prices representing the estimated value of the imbalances upon settlement. Changes in natural gas prices may impact our valuation. We do not value our imbalances based on current month-end spot prices because it is not likely that we would purchase or receive natural gas at that point in time to settle the imbalance. Natural gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our accompanying consolidated balance sheets. Our imbalance receivables and imbalance payables were as follows at December 31 (in thousands):

	2003	2002
Imbalance Receivables		
Trade	$37,228	$ 88,929
Affiliates	$16,405	$ 15,460
Imbalance Payables		
Trade	$68,446	$104,035
Affiliates	$14,047	$ 22,316

Property, Plant and Equipment

We record our property, plant and equipment at its original cost of construction or, upon acquisition, the fair value of the asset acquired. Additionally, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and, in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We also capitalize the major units of property replacements or improvements and expense minor items including repair and maintenance costs. In addition, we reduce our property, plant and equipment balance for any amounts that we receive in the form of contributions in aid of construction.

For our regulated interstate system and storage facility we use the composite (group) method to depreciate regulated property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff to the total cost of the group until its net book value equals its estimated salvage value. Currently, depreciation rates on our regulated interstate system and storage facility vary from 1 to 20 percent. Using these rates, the remaining depreciable lives of these assets range from 1 to 39 years.

Our non-regulated gathering pipelines, platforms and related facilities, processing facilities and equipment, and storage facilities and equipment are depreciated on a straight-line basis over the estimated useful lives which are as follows:

Gathering pipelines..	5-40 years
Platforms and facilities..................................	18-30 years
Processing facilities.....................................	25-30 years
Storage facilities..	25-30 years

We account for our oil and natural gas exploration and production activities using the successful efforts method of accounting. Under this method, costs of successful exploratory wells, developmental wells and acquisitions of mineral leasehold interests are capitalized. Production, exploratory dry hole and other exploration costs, including geological and geophysical costs and delay rentals, are expensed as incurred. Unproved properties are assessed periodically and any impairment in value is recognized currently as depreciation, depletion and amortization expense.

Depreciation, depletion and amortization of the capitalized costs of producing oil and natural gas properties, consisting principally of tangible and intangible costs incurred in developing a property and costs of productive leasehold interests, are computed on the unit-of-production method. Unit-of-production rates are based on annual estimates of remaining proved developed reserves or proved reserves, as appropriate, for each property.

Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depreciation provisions for gathering pipelines, platforms, related facilities and oil and natural gas properties. At December 31, 2002, accrued abandonment costs were $24.6 million, of which $6.4 million was related to offshore wells. As discussed below, we adopted SFAS No. 143 Accounting for Asset Retirement Obligations on January 1, 2003 and the amounts accrued and capitalized were adjusted to conform to the provisions of that statement.

Retirements, sales and disposals of assets are recorded by eliminating the related costs and accumulated depreciation, depletion and amortization of the disposed assets with any resulting gain or loss reflected in income.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143. 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, relating to offshore wells, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

The pro forma income from continuing operations and amounts per common unit for the years ended December 31, 2002 and 2001, assuming the provisions of SFAS No. 143 were adopted prior to the earliest period presented, are shown below:

	YEARS ENDED DECEMBER 31,	
	2002	2001
Pro forma income from continuing operations	$93,932	$54,321
Pro forma income from continuing operations allocated to common unitholders	$35,369	$12,446
Pro forma basic income from continuing operations per weighted average common unit	$ 0.83	$ 0.36
Pro forma diluted income from continuing operations per weighted average common unit	$ 0.83	$ 0.36

The pro forma amount of our asset retirement obligations at December 31, 2002 and 2001, assuming asset retirement obligations as provided for in SFAS No. 143 were recorded prior to the earliest period presented was $5.7 million and $5.3 million. Our asset retirement obligation for December 31, 2003, is shown below.

YEAR	LIABILITY BALANCE AS OF JANUARY 1	ACCRETION	OTHER CHANGE IN LIABILITY	LIABILITY BALANCE AS OF DECEMBER 31
	(IN THOUSANDS)			
2003	$5,726	$442	$(246)(1)	5,922

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(1) Abandonment work performed during the year ended December 31, 2003.

Goodwill and Other Intangible Assets

We adopted the provisions of SFAS No. 142 Goodwill and Other Intangible Assets on January 1, 2002, except for goodwill and intangible assets we acquired after June 30, 2001 for which we adopted the provisions immediately. Accordingly, we record identifiable intangible assets we acquire individually or with a group of other assets at fair value upon acquisition. Identifiable intangible assets with finite useful lives are amortized to expense over the estimated useful life of the asset. Identifiable intangible assets with indefinite useful lives and goodwill are evaluated annually for impairment by comparison of their carrying amounts with the fair value of the individual assets. We recognize an impairment loss in income for the amount by which the carrying value of any identifiable intangible asset or goodwill exceeds the fair value of the specific assets. As of December 31, 2003 and 2002, we had no goodwill, other than as described below.

As of December 31, 2003 and 2002, the carrying amount of our equity investment in Poseidon exceeded the underlying equity in net assets by approximately $3.0 million. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount and will test it for impairment if an event occurs that indicates there may be a loss in value, or at least annually. Prior to January 1, 2002, we amortized this excess amount using the straight line method over approximately 30 years. This excess amount is reflected on our accompanying consolidated balance sheets in investments in unconsolidated affiliates. Our adoption of this statement did not have a material impact on our financial position or results of operations.

As part of our acquisition of the EPN Holding assets and the San Juan assets, we obtained intangible assets representing contractual rights under dedication and transportation agreements with producers. As of December 31, 2003 and 2002, the value of these intangible assets was approximately $3.4 million and

$4.0 million and is reflected on our accompanying consolidated balance sheets as intangible assets. We amortize the intangible assets acquired in the EPN Holding asset acquisition to expense using the units-of-production method over the expected lives of the reserves ranging from 26 to 45 years. We amortize the intangible assets acquired in the San Juan asset acquisition over the life of the contracts of approximately 4 years.

Impairment and Disposal of Long-Lived Assets

We apply the provisions of SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets to account for impairment and disposal of long-lived assets. Accordingly, we evaluate the recoverability of long-lived assets when adverse events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. We determine the recoverability of an asset or group of assets by estimating the undiscounted cash flows expected to result from the use and eventual disposition of the asset or group of assets at the lowest level for which separate cash flows can be measured. If the total of the undiscounted cash flows is less that the carrying amount for the assets, we estimate the fair value of the asset or group of assets and recognize the amount by which the carrying value exceeds the fair value, less cost to sell, as an impairment loss in income from operations in the period the impairment is determined.

Additionally, as required by SFAS No. 144, we classify long-lived assets to be disposed of other than by sale (e.g., abandonment, exchange or distribution) as held and used until the item is abandoned, exchanged or distributed. We evaluate assets to be disposed of other than by sale for impairment and recognize a loss for the excess of the carrying value over the fair value. Long-lived assets to be disposed of through sale recognition meeting specific criteria are classified as "Held for Sale" and measured at the lower of their cost or fair value less cost to sell. We report the results of operations of a component classified as held for sale, including any gain or loss in the period(s) in which they occur. Upon our adoption of SFAS No. 144, we reclassified our losses on the sale of long-lived assets of $0.4 million and $11.4 million for the years ended December 31, 2002 and 2001, into operating income to conform with the provisions of SFAS No. 144.

We also reclassify the asset or assets as either held for sale or as discontinued operations, depending on whether they have independently determinable cash flow and whether we have any continuing involvement.

Capitalization of Interest

Interest and other financing costs are capitalized in connection with construction and drilling activities as part of the cost of the asset and amortized over the related asset's estimated useful life.

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness using the effective interest method. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated. At December 31, 2003 and 2002, the unamortized amount of our debt issue costs included in other noncurrent assets was $29.2 million and $32.6 million. Amortization of debt issue costs for the years ended December 31, 2003, 2002 and 2001 were $7.5 million, $4.4 million and $3.6 million and are included in interest and debt expense on our consolidated statements of income.

Revenue Recognition and Cost of Natural Gas and Other Products

Revenue from gathering and transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from commodity sales is recognized upon delivery. Commodity storage revenues and platform access revenues consist primarily of fixed fees for capacity reservation and some of the transportation contracts on our Viosca Knoll system and our Indian Basin lateral also contain a fixed fee to reserve transportation capacity. These fixed fees are recognized during the month in

which the capacity is reserved by the customer, regardless of how much capacity is actually used. Revenue from processing services, treating services and fractionation services is recognized in the period the services are provided. Interruptible revenues from natural gas storage, which are generated by providing excess storage capacity, are variable in nature and are recognized when the service is provided. Other revenues generally are recorded when services have been provided or products have been delivered.

Prior to 2002, our cost of natural gas consisted primarily of natural gas purchased at GulfTerra Alabama Intrastate for resale. As a result of our acquisition of the EPN Holding assets and the San Juan assets, we are now incurring additional costs related to system imbalances and for the purchase of natural gas as part of our producer services activities. As a convenience for our producers, we may purchase natural gas from them at the wellhead at an index price less an amount that compensates us for our gathering services. We then sell this gas into the open market at points on our system at the same index price. We reflect these sales in our revenues and the related purchases as cost of natural gas on the accompanying consolidated statements of income.

Typhoon Oil Pipeline's transportation agreement with BHP and Chevron Texaco provides that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. Beginning in 2003, we record revenue from these buy/sell transactions upon delivery of the oil based on the net amount billed to the producers. We acquired the Typhoon oil pipeline in November 2002, and for the year ended December 31, 2002, we recorded revenue based on the gross amount billed to the producers. For the year ended December 31, 2002, we reclassified $10.5 million from cost of natural gas and other products to revenue to conform to our 2003 presentation. This reclassification has no effect on operating income, net income or partners' capital.

As of July 1, 2003, HIOS implemented new rates, subject to a refund, and we established a reserve for our estimate of the 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.

Environmental Costs

We expense or capitalize expenditures for ongoing compliance with environmental regulations that relate to past or current operations as appropriate. We expense amounts for clean up of existing environmental contamination caused by past operations which do not benefit future periods. We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our consolidated balance sheets in other noncurrent liabilities at their undiscounted amounts.

Accounting for Price Risk Management Activities

Our business activities expose us to a variety of risks, including commodity price risk and interest rate risk. From time to time we engage in price risk management activities for non-trading purposes to manage market risks associated with commodities we purchase and sell and interest rates on variable rate debt. Our price risk management activities involve the use of a variety of derivative financial instruments, including:

- exchange-traded future contracts that involve cash settlement;

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

- forward contracts that involve cash settlements or physical delivery of a commodity; and

- swap contracts that require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity or variable rate debt instrument.

We account for all of our derivative instruments in our consolidated financial statements under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. We record all derivatives in our consolidated balance sheets at their fair value as other assets or other liabilities and classify them as current or noncurrent based upon their anticipated settlement date.

For those instruments entered into to hedge risk and which qualify as hedges, we apply the provisions of SFAS No. 133, and the accounting treatment depends on each instrument's intended use and how it is designated. In addition to its designation, a hedge must be effective. To be effective, changes in the value of the derivative or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking various hedge transactions. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is not highly effective as a hedge or if we decide to discontinue the hedging relationship.

During 2003, 2002 and 2001, we entered into cash flow hedges that qualify for hedge accounting under SFAS No. 133 treatment. Changes in the fair value of a derivative designated as a cash flow hedge are recorded in accumulated other comprehensive income for the portion of the change in value of the derivative that is effective. The ineffective portion of the derivative is recorded in earnings in the current period. Classification in the income statement of the ineffective portion is based on the income classification of the item being hedged. At the date of the hedged transaction, we reclassify the gains or losses resulting from the sale, maturity, extinguishment or termination of derivative instruments designated as hedges from accumulated other comprehensive income to operating income or interest expense, as appropriate, in our consolidated statements of income. We classify cash inflows and outflows associated with the settlement of our derivative transactions as cash flows from operating activities in our consolidated statements of cash flows.

We also record our ownership percentage of the changes in the fair value of derivatives of our investments in unconsolidated affiliates in accumulated other comprehensive income.

We may also purchase and sell instruments to economically hedge price fluctuations in the commodity markets. These instruments are not documented as hedges due to their short-term nature, or do not qualify under the provisions of SFAS No. 133 for hedge accounting due to the terms in the instruments. Where such derivatives do not qualify, or are not documented, changes in their fair value are recorded in earnings in the current period.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices in the San Juan Basin in anticipation of our acquisition of the San Juan assets. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative through current earnings since it did not qualify for hedge accounting under SFAS No. 133. Beginning with the acquisition date in November 2002, we have designated this derivative as a cash flow hedge and are accounting for it as such under SFAS No. 133.

During the normal course of our business, we may enter into contracts that qualify as derivatives under the provisions of SFAS No. 133. As a result, we evaluate our contracts to determine whether derivative

accounting is appropriate. Contracts that meet the criteria of a derivative and qualify as "normal purchases" and "normal sales", as those terms are defined in SFAS No. 133, may be excluded from SFAS No. 133 treatment.

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 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.

Income Taxes

As of December 31, 2003, neither we nor any of our subsidiaries are taxable entities. However, the taxable income or loss resulting from our operations will ultimately be included in the federal and state income tax returns of the general and limited partners. Individual partners will have different investment bases depending upon the timing and price of their acquisition of partnership units. Further, each partner's tax accounting, which is partially dependent upon his tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual partner's tax basis and his share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual partner's tax attributes and the aggregate tax bases cannot be readily determined.

Income (Loss) per Common Unit

Basic income (loss) per common unit excludes dilution and is computed by dividing net income (loss) attributable to the common unitholders by the weighted average number of common units outstanding during the period. Diluted income (loss) per common unit reflects potential dilution and is computed by dividing net income (loss) attributable to the common unitholders by the weighted average number of common units outstanding during the period increased by the number of additional common units that would have been outstanding if the potentially dilutive units had been issued.

Basic income (loss) per common unit and diluted income (loss) per common unit are the same for the years ended December 31, 2002 and 2001, as the number of potentially dilutive units were so small as not to cause the diluted earnings per unit to be different from the basic earnings per unit.

Comprehensive Income

Our comprehensive income is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income (loss) from our cash flow hedging activities associated with our GulfTerra Alabama Intrastate operations, our Indian Basin processing plant, the San Juan assets and our unconsolidated affiliate, Poseidon Oil Pipeline Company, L.L.C.

The following table presents our allocation of accumulated other comprehensive loss as of December 31:

	2003	2002	2001
Common units' interest	$(7,488)	$(4,623)	$(1,259)
Series C units' interest	$(1,409)	$ (942)	$ --
General partner's interest	$ (130)	$ (57)	$ (13)

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 years ending December 31, 2003, 2002 and 2001, 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, Accounting for Stock-Based Compensation, 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 our net income allocated to common unitholders and net income per common unit would have approximated the pro forma amounts below:

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS)		
Net income, as reported	$163,139	$97,688	$55,149
Add: Stock-based employee compensation expense included in reported net income	1,489	1,168	367
Less: Stock-based employee compensation expense determined under fair value based method	1,532	1,912	678
Pro forma net income	$163,096	$96,944	$54,838
Pro forma net income allocated to common unitholders	$ 66,452	$38,616	$12,949
Earnings per common unit:			
Basic, as reported	$ 1.33	$ 0.92	$ 0.38
Basic, pro forma	$ 1.33	$ 0.90	$ 0.38
Diluted, as reported	$ 1.32	$ 0.92	$ 0.38
Diluted, pro forma	$ 1.32	$ 0.90	$ 0.38

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

Accounting for Debt Extinguishments

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 a component of 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 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.

New Accounting Pronouncements Issued But Not Yet Adopted

Consolidation of Variable Interest Entities

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 do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires a company to consolidate a VIE if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. In December 2003, the FASB issued FIN 46-R, which amended FIN No. 46, to extend its effective date until the first quarter of 2004 for all types of entities except special purpose entities (SPE's). In addition, FIN No. 46-R also limited the scope of FIN No. 46 to exclude certain joint ventures of other entities that meet the characteristics of businesses.

We have no SPE's as defined by FIN Nos. 46 and 46-R. We have evaluated our joint ventures, unconsolidated subsidiaries and other contractual arrangements that could be considered variable interests or variable interest entities that were created before February 1, 2003 and have determined that they will not have a significant effect on our reported results and financial position when we adopt the provisions of FIN No. 46-R in the first quarter of 2004.

2. ACQUISITIONS AND DISPOSITIONS

Merger with Enterprise

On December 15, 2003, we, along with Enterprise and El Paso Corporation, announced that we had executed definitive agreements to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs. The general partner of the combined partnership will be jointly owned by affiliates of El Paso Corporation and privately-held Enterprise Products Company, with each owning a 50-percent interest. The definitive agreements include three transactions, of which two affect us.

In the first transaction that effects us, which occurred with the signing of the merger agreement, a wholly owned subsidiary of Enterprise purchased a 50 percent limited-voting interest in our general partner. This interest entitles Enterprise to half of the cash distributed to our general partner, but does not allow Enterprise to elect any of our general partner's directors or otherwise generally participate in our general partner's management of our business.

The second transaction that affects us will occur at the merger date. At the closing of the merger, each outstanding GulfTerra common unit (other than those owned by Enterprise) will convert into 1.81 Enterprise common units, GulfTerra will become a wholly-owned subsidiary of Enterprise, and El Paso Corporation will acquire a 50 percent interest in Enterprise's general partner (including the right to elect half of the directors of Enterprise's general partner). The closing of the merger is subject to the satisfaction of specified conditions, including obtaining clearance under the Hart-Scott-Rodino Antitrust Improvement Acts, and the approval of our unitholders and Enterprise's unitholders. Completion of the merger is expected to occur during the second half of 2004.

Our merger agreement with Enterprise limits our ability to raise additional capital prior to the closing of the merger without Enterprise's approval. In addition, because the closing of the merger will be a change of control, and thus a default, under our credit facility, we will either repay or amend that facility prior to the closing. In addition, because the merger closing will constitute a change of control under our indentures, we will be required to offer to repurchase our outstanding senior subordinated notes (and possibly our senior notes) at 101 percent of their principal amount after the closing. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the close of the merger. We and Enterprise can agree on the date of the merger closing after the receipt of all necessary approvals. We do not intend to close until appropriate financing is in place.

If the merger agreement is terminated and (1) a business transaction between us and a third party that conflicts with the merger was proposed and certain other conditions were met or (2) we materially and willfully violated our agreement not to solicit transactions that conflict with the merger, then we will be required to pay Enterprise a termination fee of $112 million. If the merger agreement is terminated because our unitholders did not approve the merger and either (1) a possible business transaction involving us but not involving Enterprise and conflicting with the merger was publicly proposed and our board of directors publicly and timely reaffirmed its recommendations of the Enterprise merger or (2) no such possible business transaction was publicly announced, then we will be required to pay Enterprise a termination fee of $15 million. Enterprise is subject to similar termination fee requirements.

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. In October 2003, we released El Paso Corporation from that obligation in exchange for El Paso Corporation contributing specified communication assets and other rights to us. The communication assets we received are 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 communication 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 revised our estimate for the depreciable life of the Chaco plant from 19 to 30 years, the estimated remaining useful life of the Chaco plant. 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 3 for a discussion related to our sale of a 50 percent interest in Cameron Highway Oil Pipeline.

San Juan Assets

In November 2002, we acquired from subsidiaries of El Paso Corporation, interests in assets we collectively refer to as the San Juan assets, which consist of the following:

- 100 percent of El Paso Field Services' San Juan Gathering and Processing Businesses, which include a natural gas gathering system and related compression facilities, the Rattlesnake Treating Plant, a 50-percent equity interest in Coyote Gas Treating, L.L.C. which owns the Coyote natural gas treating facility, and the remaining interests in the Chaco cryogenic natural gas processing plant we did not already own, all of which are located in the San Juan Basin of northwest New Mexico and southwestern Colorado;

- 100 percent of the Typhoon Oil Pipeline assets located in the Deepwater Trend area of the Gulf of Mexico. Typhoon Oil was placed in service in July 2001 and provides transportation of oil produced from the Typhoon field for delivery to a platform in Green Canyon Block 19 with onshore access through various oil pipelines;

- 100 percent of the Typhoon Gas Pipeline, which was placed in service in August 2001. Typhoon Gas is also located in the Deepwater Trend area of the Gulf of Mexico. The pipeline gathers natural gas from the Typhoon field for redelivery into El Paso Corporation's ANR Patterson System; and

- 100 percent of the Coastal Liquids Partners' NGL Business, consisting of an integrated set of NGL assets that stretch from the Mexico border near McAllen, Texas, to Houston, Texas. This business includes a fractionation facility near Houston, Texas; a truck-loading terminal near McAllen, Texas, and leased underground NGL storage facilities.

We purchased the San Juan assets for $782 million, $764 million after adjustments for capital expenditures and actual working capital acquired. During 2003, the total purchase price and net assets acquired decreased $2.4 million due to post-closing purchase price adjustments related to natural gas imbalances, NGL in-kind reserves and well loss reserves. We financed the purchase of these assets with net proceeds from an offering of $200 million of 10 5/8% Senior Subordinated Notes due 2012; borrowings of $237.5 million under our senior secured acquisition term loan; our issuance, to El Paso Corporation, of 10,937,500 of our Series C units valued at $32 per unit or $350 million; and currently available funds. We acquired the San Juan assets because they are strategically located in active supply development areas and are supported by long-term contracts that provide us with growing and reliable cash flows consistent with our stated growth strategy.

In connection with this acquisition, we entered into an agreement with El Paso Corporation under which El Paso Corporation would have been required, subject to specified conditions, to repurchase the Chaco plant from us for $77 million in October 2021, at which time we would have had the right to lease the plant from them for a period of 10 years with the option to renew the lease annually thereafter. In October 2003, we

released El Paso Corporation from that repurchase obligation in exchange for El Paso Corporation contributing communication assets to us.

As a result of our acquisition of the San Juan assets, our financial results from the operation of the Chaco plant are significantly different from our results prior to the purchase in the following ways:

- We no longer receive fixed fee revenue of $0.134/Dth for natural gas processed; rather, from a majority of our customers, we receive a processing fee of an in-kind portion of the NGL produced from the natural gas processed. We then sell these NGL and, accordingly, our processing revenues are affected by changes in the price of NGL.

- We no longer receive revenue for leasing the Chaco plant to El Paso Field Services.

- We no longer recognize amortization expense relating to our investment in processing agreement, which we terminated upon completing the acquisition. This decrease in amortization expense is offset by additional depreciation expense associated with the acquired assets.

In accordance with our procedures for evaluating and valuing material acquisitions with El Paso Corporation, our Audit and Conflicts Committee engaged independent financial advisors. Separate financial advisors delivered fairness opinions for the acquisition of the San Juan assets and the issuance of the Series C units. Based on these opinions, our Audit and Conflicts Committee and the full Board approved these transactions.

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at November 27, 2002. 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

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we are amortizing to expense over the life of the contracts of approximately 4 years. We recorded adjustments to the purchase price of approximately $18 million primarily for capital expenditures and actual working capital acquired.

Our consolidated financial statements include the results of operations of the San Juan assets from the November 27, 2002 purchase date. We have included the assets and operating results of the El Paso Field Services' San Juan Gathering and Processing Businesses and the Typhoon Gas Pipeline in our natural gas pipelines and plants segment and the assets and operating results of the Typhoon Oil Pipeline and Coastal Liquids Partners' NGL Business in our oil and NGL logistics segment from the purchase date. The following

selected unaudited pro forma financial information presents our consolidated operating results for the years ended December 31, 2002 and 2001 as if we acquired the San Juan assets on January 1, 2001:

	2002	2001
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$627,191	$427,942
Income from continuing operations	$ 88,902	$ 77,219
Income allocated to common unitholders from continuing operations	$ 25,738	$ 16,687
Basic and diluted net income per unit from continuing operations	$ 0.60	$ 0.43

The unaudited pro forma financial information presented above is not necessarily indicative of the results of operations we might have realized had the transaction been completed at the beginning of the earliest period presented, nor do they necessarily indicate our consolidated operating results for any future period.

EPN Holding Assets

In April 2002, we acquired, through a series of related transactions, from subsidiaries of El Paso Corporation the following midstream assets located in Texas and New Mexico, which we collectively refer to, for purposes of these financial statements, as the EPN Holding assets:

- The Waha natural gas gathering and treating system and the Carlsbad natural gas gathering system which are generally located in the Permian Basin region of Texas and New Mexico.

- A 50 percent undivided interest in the Channel Pipeline System, an intrastate natural gas transmission system located along the Gulf Coast of Texas.

- The TPC Offshore pipeline system, a collection of natural gas gathering and transmission assets located offshore of Matagorda Bay, Texas, including the Oyster Lake and MILSP Condensate Separation and Stabilization facilities and other undivided interests in smaller pipelines.

- GulfTerra Texas Pipeline, L.P. which owned, among other assets, (i) the GulfTerra Texas intrastate pipeline system, (ii) the TGP natural gas lateral pipelines, (iii) the leased natural gas storage facilities located in Wharton County, Texas generally known as the Wilson Storage facility, (iv) an 80 percent undivided interest in the East Texas 36 inch pipeline, (v) a 50 percent undivided interest in the West Texas 30 inch pipeline, (vi) a 50 percent undivided interest in the North Texas 36 inch pipeline, (vii) the McMullen County natural gas gathering system, (viii) the Hidalgo County natural gas gathering system, (ix) a 22 percent undivided interest in the Bethel-Howard pipeline, and (x) a 75 percent undivided interest in the Longhorn pipeline.

- El Paso Hub Services L.L.C. which owned certain contract rights and parcels of real property located in Texas.

- 100 percent of the outstanding joint venture interest in Warwink Gathering and Treating Company which owned, among other assets, the Warwink natural gas gathering system located in the Permian Basin region of Texas and New Mexico.

In conjunction with the acquisition of the above assets, we obtained from another affiliate of El Paso Corporation, all of the equity interest in El Paso Indian Basin, L.P. which owned a 42.3 percent undivided, non-operating interest in the Indian Basin natural gas processing plant and treating facility located in southeastern New Mexico and the price risk management activities associated with the plant.

We acquired the EPN Holding assets to provide us with a significant new source of cash flow, greater diversification of our midstream asset base and to provide new long term internal growth opportunities in the Texas intrastate market. We purchased the EPN Holding assets for $750 million, adjusted for the assumption

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

of $15 million of net working capital obligations related to natural gas imbalances resulting in net consideration of $735 million comprised of the following:

- $420 million of cash;

- $119 million of assumed short-term indebtedness payable to El Paso

Corporation, which we subsequently repaid;

- $6 million in common units; and

- $190 million in assets, comprised of our Prince TLP and our nine percent overriding royalty interest in the Prince field (see discussion below).

During 2003, the purchase price and net assets acquired increased $17.5 million due to post-closing purchase price adjustments related primarily to a reduction in natural gas imbalance payables assumed in the transaction.

We entered into a limited recourse credit agreement with a syndicate of commercial banks to finance substantially all of the cash consideration associated with this transaction. See Note 6 for additional discussion regarding the EPN Holding term credit facility.

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at April 8, 2002. 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

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we will amortize to expense using the units-of-production method over the expected lives of the underlying reserves ranging from 26 to 45 years. Additionally, we assumed environmental liabilities of $21.1 million for estimated environmental remediation costs associated with the GulfTerra Texas intrastate pipeline assets as discussed in Note 11.

Our consolidated financial statements include the results of operations of the EPN Holding assets from the April 8, 2002 purchase date. We have included the assets and operating results of the Waha, Carlsbad and Warwink natural gas gathering systems; the Channel and TPC Offshore pipeline systems; and the GulfTerra Texas pipeline assets (excluding the Wilson Storage facility) in our natural gas pipelines and plants segment. Our 42.3 percent ownership interest in the assets and operating results of the Indian Basin plant are included in our oil and NGL logistics segment and the Wilson storage facility assets and operating results are included in our natural gas storage segment. The following selected unaudited pro forma information depicts our

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

consolidated results of operations for the years ended December 31, 2002 and 2001 as if we acquired the EPN Holding assets on January 1, 2001:

	2002	2001
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$540,154	$538,095
Income from continuing operations	$114,517	$ 81,022
Income allocated to common unitholders from continuing operations	$ 56,020	$ 38,874
Basic and diluted net income per unit from continuing operations	$ 1.31	$ 1.13

The unaudited pro forma financial information presented above is not necessarily indicative of the results of operations we might have realized had the transaction been completed at the beginning of the earliest period presented, nor do they necessarily indicate our consolidated operating results for any future period.

Prince Assets

In connection with our April 2002 acquisition of the EPN Holding assets from El Paso Corporation, we sold our Prince tension leg platform (TLP) and our nine percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation. The results of operations for these assets have been accounted for as discontinued operations and have been excluded from continuing operations for all periods in our consolidated statements of income. Accordingly, the segment results in Note 15 reflect neither the results of operations for the Prince assets nor the related net assets held for sale. The Prince TLP was previously included in the platform services segment and related royalty interest was included in non-segment activity. Included in income from discontinued operations for the years ended December 31, 2002 and 2001 were revenues of $7.8 million and $8.8 million attributable to these disposed assets.

In April 2002, we sold the Prince assets for $190 million and recognized a gain on the sale of $0.4 million during 2002. In conjunction with this transaction, we repaid the related outstanding $95 million principal balance under our Argo term loan.

Deepwater Holdings L.L.C. and Chaco Transaction

In October 2001, we acquired the remaining 50 percent interest that we did not already own in Deepwater Holdings for approximately $81 million, consisting of $26 million cash and $55 million of assumed indebtedness, and at the acquisition date also repaid all of Deepwater Holdings' $110 million of indebtedness. HIOS and East Breaks became indirect wholly-owned assets through this transaction. In a separate transaction, we acquired interests in the title holder of, and other interests in the Chaco cryogenic natural gas processing plant for $198.5 million. The total purchase price was composed of a payment of $77 million to acquire the plant from the bank group that provided the financing for the construction of the facility and a payment of $121.5 million to El Paso

Field Services in connection with the execution of a 20-year fee-based processing agreement relating to the processing capacity of the Chaco plant and dedication of natural gas gathered by El Paso Field Services to the Chaco plant. Under the terms of the processing agreement, we received a fixed fee for each dekatherm of natural gas that we processed at the Chaco plant, and we bore all costs associated with the plant's ownership and operations. El Paso Field Services personnel continued to operate the plant. In accordance with the original construction financing agreements, the Chaco plant was under an operating lease to El Paso Field Services. El Paso Field Services had the right to repurchase the Chaco plant at the end of the lease term in October 2002 for approximately $77 million. We funded both of these transactions by borrowing from our revolving credit facility. We accounted for these transactions as purchases and have assigned the purchase price to the net assets acquired based upon the estimated fair value of the net assets as of the acquisition date. The operating results associated with Deepwater Holdings are included in earnings from unconsolidated affiliates for the periods prior to October 2001. We have included the

operating results of Deepwater Holdings and the Chaco plant in our consolidated financial statements from the acquisition date.

Since the Chaco transaction was an asset acquisition, we have assigned the total purchase price to property, plant and equipment and investment in processing agreement. Since the Deepwater Holdings transaction was an acquisition of additional interests in a business, we are providing summary information related to the acquisition of Deepwater Holdings in the following table (in thousands):

Fair value of assets acquired	$ 81,331
Cash acquired	5,386
Fair value of liabilities assumed	(60,917)
Net cash paid	$ 25,800

In connection with our acquisition of the San Juan assets in November 2002, the original terms of the processing, lease and operating agreements between the Chaco plant and El Paso Field Services were terminated. The effect on our operation of the Chaco plant resulting from our acquisition of the San Juan assets is discussed above.

GTM Texas (formerly EPN Texas)

In February 2001, we acquired GTM Texas from a subsidiary of El Paso Corporation for $133 million. We funded the acquisition of these assets by borrowing from our revolving credit facility. These assets include more than 500 miles of NGL gathering and transportation pipelines. The NGL pipeline system gathers and transports unfractionated and fractionated products. We also acquired three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGL into ethane, propane, butane and natural gasoline products that are used by refineries and petrochemical plants along the Texas Gulf Coast. We accounted for the acquisition as a purchase and assigned the purchase price to the assets acquired based upon the estimated fair value of the assets as of the acquisition date. We have included the operating results of GTM Texas in our consolidated financial statements from the acquisition date.

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the year ended December 31, 2001, as if we acquired GTM Texas, the Chaco plant and the remaining 50 percent interest in Deepwater Holdings on January 1, 2001:

	2001 (IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
Operating revenues	$269,681
Operating income	$101,406
Net income allocated to limited partners	$ 39,157
Basic and diluted net income per unit	$ 1.14

Gulf of Mexico Assets

In accordance with an FTC order related to El Paso Corporation's merger with The Coastal Corporation, we, along with Deepwater Holdings, agreed to sell several of our offshore Gulf of Mexico assets to third parties in January 2001. Total consideration received for these assets was approximately $163 million consisting of approximately $109 million for the assets we sold and approximately $54 million for the assets Deepwater Holdings sold. The offshore assets sold include interests in Stingray, UTOS, Nautilus, Manta Ray Offshore, Nemo, Tarpon, and the Green Canyon pipeline assets, as well as interests in two offshore platforms and one dehydration facility. We recognized net losses from the asset sales of approximately $12 million, and Deepwater Holdings recognized losses of approximately $21 million. Our share of Deepwater Holdings' losses

was approximately $14 million, which has been reflected in earnings from unconsolidated affiliates in the accompanying 2001 consolidated statement of income.

As additional consideration for the above transactions, El Paso Corporation agreed to make payments to us totaling $29 million. These payments were made in quarterly installments of $2.25 million for three years beginning in 2001 and we will receive the final payment of $2 million in the first quarter of 2004. From this additional consideration, we realized income of approximately $25 million in the first quarter of 2001, which has been reflected in other income in the accompanying 2001 consolidated statement of income.

3. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. As of December 31, 2003, the carrying amount of our equity investments exceeded the underlying equity in net assets by approximately $3.0 million, which is included in our oil and NGL logistics segment. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount, refer to Note 1, Summary of Significant Accounting Policies, Goodwill and Other Intangible Assets. Summarized financial information for these investments is as follows:

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2003				
	COYOTE	DEEPWATER GATEWAY(C)	CAMERON HIGHWAY(C)	POSEIDON	TOTAL
	(IN THOUSANDS)				
END OF PERIOD OWNERSHIP INTEREST	50%	50%	50%	36%	
OPERATING RESULTS DATA:					
Operating revenues	$ 7,200	$ --	$ --	$ 41,293	
Other income	7	47	37	56	
Operating expenses	(355)	--	--	(3,694)	
Depreciation	(1,381)	--	--	(8,316)	
Other expenses	(736)	(31)	(171)	(6,313)	
Net income (loss)	$ 4,735	$ 16	$ (134)	$ 23,026	
OUR SHARE:					
Allocated income (loss)	$ 2,368	$ 8	$ (67)	$ 8,289	
Adjustments(a)	9	(8)	67	(191)	
Earnings from unconsolidated affiliate	$ 2,377	$ --	$ --	$ 8,098	$11,373(b)
Allocated distributions	$ 3,500	$ --	$ --	$ 8,640	$12,140
FINANCIAL POSITION DATA:					
Current assets	$ 987	$ 8,271	$ 53,644	$ 98,937	
Noncurrent assets	31,897	230,825	266,554	218,893	
Current liabilities	34,784	18,294	26,332	91,146	
Noncurrent liabilities	--	155,000	125,000	123,000	

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

(b) Total earnings from unconsolidated affiliates includes a $898 thousand gain associated with the sale of our interest in Copper Eagle.

(c) Cameron Highway Oil Pipeline Company and Deepwater Gateway, L.L.C. are development stage companies; therefore there are no operating revenues or operating expenses to provide operational results. Since their formations, they have incurred organizational expenses and received interest income.

Cameron Highway. 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 fourth quarter of 2004. We entered into producer agreements with three major anchor producers, BP Exploration & Production Company, BHP Billiton Petroleum (Deepwater), Inc., and Union Oil Company of California, 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 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 $5 million once the system is completed and another $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 statement of income. 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 Highway'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 37 percent equity, or $169 million through capital contributions from us and Valero, the two Cameron Highway partners, which contributions have already been made, and 63 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. As of December 31, 2003, Cameron Highway has spent approximately $256 million (of which $85 million constituted equity contributions by us) related to this pipeline, which is in the construction stage. 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 initial equity contributions and proceeds from Cameron Highway's project loan facility.

Deepwater Gateway. As of December 31, 2003, we have contributed $33 million, as our 50 percent share, to Deepwater Gateway, which amount satisfies our initial equity funding requirement related to the Marco Polo TLP. We expect that the remaining costs associated with the Marco Polo TLP will be funded through the $155 million project finance loan and Deepwater Gateway's members' contingent equity obligations (of which our share is $14 million). This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. The loan agreement requires Deepwater Gateway to maintain a debt service reserve equal to six months' interest. Other than that debt service reserve and any other reserve amounts agreed upon by more than 66.7 percent majority interest of Deepwater Gateway's members, Deepwater Gateway will (after the project finance loan is either repaid or converted into a term loan) distribute any available cash to its members quarterly. Deepwater Gateway is not currently generating income or cash flow. Deepwater Gateway is managed by a management committee consisting of representative from each of its members.

Front Runner Oil Pipeline. 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 platform with Poseidon's existing system at Ship Shoal Block 332. The new 36-mile, 14-inch pipeline is expected to be operational by the third quarter of 2004 and have a capacity of 65 MBbls/d. As Poseidon expects to fund Front Runner's capital expenditures from its operating cash flow and from its revolving credit

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

facility, we do not expect to receive distributions from Poseidon until the Front Runner oil pipeline is completed.

	AS OF OR FOR THE YEAR ENDED DECEMBER 31,			
	COYOTE(A)	POSEIDON	DEEPWATER GATEWAY(B)	T
	(IN THOUSANDS)			
END OF PERIOD OWNERSHIP INTEREST	50%	36%	50%	
OPERATING RESULTS DATA:				
Operating revenues	$ 635	$ 54,261	$ --	
Other income	2	26,695	20	
Operating expenses	(38)	(4,691)	--	
Depreciation	(110)	(8,356)	--	
Other expenses	(75)	(6,923)	(234)	
Net income (loss)	$ 414	$ 60,986	$ (214)	
OUR SHARE:				
Allocated income (loss)	$ 207	$ 21,955	$ (107)	
Adjustments(c)	(13)	(8,510)	107	
Earnings from unconsolidated affiliate	$ 194	$ 13,445	$ --	$1
Allocated distributions	$ 2,000	$ 15,804	$ --	$1
FINANCIAL POSITION DATA:				
Current assets	$ 1,575	$ 152,784	$ 10,745	
Noncurrent assets	33,349	218,463	110,309	
Current liabilities	34,559	119,974	28,268	
Noncurrent liabilities	--	148,000	27,000	

(a) We acquired an interest in Coyote Gas Treating, L.L.C. in November 2002 as part of the San Juan assets acquisition.

(b) In June 2002, we formed Deepwater Gateway, L.L.C., a 50/50 joint venture with Cal Dive International, Inc., to construct and install the Marco Polo TLP. Also in August 2002, Deepwater Gateway obtained a project finance loan to fund a substantial portion of the cost to construct the Marco Polo TLP. For further discussion of this project loan, see Note 6, Financing Transactions. Deepwater Gateway, L.L.C. is a development stage company; therefore there are no operating revenues or operating expenses to provide operational results. Since Deepwater Gateway's formation in 2002, it has incurred organizational expenses and received interest income.

(c) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on our Form 10-K and actual earnings recorded in the audited annual reports of our unconsolidated affiliates. The adjustment for Poseidon primarily represents the receipt of proceeds from a favorable litigation related to the January 2000 pipeline rupture.

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2001			
	DEEPWATER HOLDINGS(A)	POSEIDON	DIVESTED INVESTMENTS(B)	OTHER(C)
		(IN THOUSANDS)		
END OF PERIOD OWNERSHIP INTEREST.......	100%	36%	--	50%
OPERATING RESULTS DATA:				
Operating revenues...................	$ 40,933	$ 70,401	$1,982	$145
Other income (loss)..................	--	394	(85)	--
Operating expenses...................	(16,740)	(1,586)	(590)	(73)
Depreciation.........................	(8,899)	(10,552)	(953)	--
Other (expenses) income..............	(5,868)	(7,668)	222	(22)
Loss on sale of assets...............	(21,453)	--	--	--
Net income (loss)....................	$(12,027)	$ 50,989	$ 576	$ 50
OUR SHARE:				
Allocated income (loss)(d)...........	$ (9,925)	$ 18,356	$ 148	$ 25
Adjustments(e).......................	--	(146)	(9)	--
Earnings (loss) from unconsolidated affiliates.......................	$ (9,925)	$ 18,210	$ 139	$ 25
Allocated distributions..............	$ 12,850	$ 22,212	$ --	$ --
FINANCIAL POSITION DATA:				
Current assets.......................		$ 91,367		$177
Noncurrent assets....................		226,570		--
Current liabilities..................		80,365		33
Noncurrent liabilities...............		150,000		--

(a) In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. Deepwater Holdings sold its interest in its UTOS subsidiary in April 2001. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings and as a result of this transaction, from the acquisition date Deepwater Holdings is consolidated in our financial statements. The information presented for Deepwater Holdings as an equity investment is through October 18, 2001.

(b) Divested Investments contains Manta Ray Offshore Gathering Company, L.L.C. and Nautilus Pipeline Company L.L.C. In January 2001, we sold our 25.67 percent interest in Manta Ray Offshore and our 25.67 percent interest in Nautilus.

(c) Through October 2001 this company processed gas for Deepwater Holdings' Stingray subsidiary. This agreement was terminated in October 2001, and as of this date there are no operations related to this investment.

(d) The income (loss) from Deepwater Holdings is not allocated proportionately with our ownership percentage because the capital contributed by us was a larger amount of the total capital at the time of formation. Therefore, we were allocated a larger amount of amortization of Deepwater Holdings' excess purchase price of its investments. Also, we were allocated a larger portion of Deepwater Holdings' $21 million loss incurred in 2001 due to the sale of Stingray, UTOS, and the West Cameron dehydration facility. Our total share of the losses relating to these sales was approximately $14 million.

(e) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on Form 10-K and actual earnings reported in the audited annual reports of our unconsolidated affiliates.

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

4. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	DECEMBER 31, 2003	DECEMBER 31, 2002
	(IN THOUSANDS)	
Property, plant and equipment, at cost(1)		
Pipelines	$2,487,102	$2,317,503
Platforms and facilities	121,105	128,582
Processing plants	305,904	300,897
Oil and natural gas properties	131,100	127,975
Storage facilities	337,535	331,562
Construction work-in-progress	383,640	177,964
	3,766,386	3,384,483
Less accumulated depreciation, depletion and amortization	871,894	659,545
Total property, plant and equipment, net	$2,894,492	$2,724,938

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(1) Includes leasehold acquisition costs with an unamortized balance of $3.2 million and $4.1 million at December 31, 2003 and 2002. 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 consolidated balance sheets. We will continue to include these costs in property, plant, and equipment until further guidance is provided.

Due to the sale of our interest in the Manta Ray Offshore system in January 2001, we lost a primary connecting point to our Manta Ray pipeline. As a result, we abandoned the Manta Ray pipeline and recorded an impairment of approximately $3.9 million in the first quarter of 2001 which is reflected in the natural gas pipelines and plants segment.

5. INVESTMENT IN PROCESSING AGREEMENT

As part of our October 2001 Chaco transaction, we paid $121.5 million to El Paso Field Services for a 20-year fee-based processing agreement. The processing agreement was being amortized on a straight-line basis over the life of the agreement and we recorded amortization expense of $5.6 million in 2002 and $1.5 million in 2001 related to this asset. As a result of the San Juan acquisition in November 2002, we now own the gathering system and related facilities previously owned by El Paso Field Services, including the rights of El Paso Field Services under the arrangements relating to the Chaco plant. As part of the San Juan acquisition, the processing agreement was terminated.

6. FINANCING TRANSACTIONS

CREDIT FACILITY

Our credit facility consists of two parts: the revolving credit facility maturing in 2006 and a senior secured term loan maturing in 2008. Our credit facility is guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries, as detailed in Note 16, and are collateralized with substantially all of our assets (excluding the assets of our unrestricted subsidiaries). The interest rates we are charged on our credit facility are 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. 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%.

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. The financial covenants associated with our credit facility are as follows:

(a) The ratio of consolidated EBITDA, as defined in our credit agreements, to consolidated interest expense cannot be less than 2.0 to 1.0;

(b) The ratio of consolidated total senior indebtedness on the last day of any fiscal quarter to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 3.25 to 1.0; and

(c) The ratio of our consolidated total indebtedness on the last day of any fiscal quarter to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 5.25 to 1.0.

Among other things, our credit agreement includes as an event of default a change of control, defined as the failure of El Paso Corporation and its subsidiaries to no longer own at least 50 percent of our general partner. We are in compliance with the financial ratios and covenants contained in each of our credit facilities at December 31, 2003.

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.

At December 31, 2003, we had $382 million outstanding under our revolving credit facility at an average interest rate of 3.17%. We may elect that all or a portion of the revolving credit facility bear interest at either the variable rate described above increased by 1.0% or LIBOR increased by 2.0%. The total amount available to us at December 31, 2003, under this facility was $318 million.

Senior Secured Term Loan

In December 2003, we refinanced the term loan portion of our credit facility to provide greater financial flexibility by, among other things, expanding the existing term component from $160 million to $300 million, extending the maturity from October 2007 to December 2008, reducing the semi-annual payments from $2.5 million to $1.5 million and reducing the interest rate we are charged by 1.25%. We used the proceeds from the term loan to repay the $155 million outstanding under the initial term loan and to temporarily reduce amounts outstanding under our revolving credit facility. We charged $2.8 million to interest and debt expense in December 2003 to write-off unamortized debt issuance costs associated with the initial term loan.

The senior secured term loan is payable in semi-annual installments of $1.5 million in June and December of each year for the first nine installments and the remaining balance at maturity in December 2008. We may elect that all or a portion of the senior secured term loan bear interest at either 1.25% over the variable base rate discussed above; or LIBOR increased by 2.25%. As of December 31, 2003, we had $300 million outstanding with an average interest rate of 3.42%.

GulfTerra Holding Term Credit Facility (formerly EPN Holding Term Credit Facility)

In connection with our acquisition of the EPN Holding assets from El Paso Corporation in April 2002, EPN Holding entered into a $560 million term credit facility with a group of commercial banks. The term credit facility provided a term loan (the GulfTerra Holding term loan) of $535 million to finance the acquisition of the EPN Holding assets, and a revolving credit facility (the GulfTerra Holding revolving credit facility) of up to $25 million to finance EPN Holding's working capital. At the time of its acquisition, EPN Holding borrowed $535 million ($531 million, net of issuance costs) under this term loan and had $25 million available under the GulfTerra Holding revolving credit facility. We used net proceeds of approximately $149 million from our April 2002 common unit offering, $0.6 million contributed by our general partner to maintain its one percent capital account balance and $225 million of the net proceeds from our May 2002 offering of 8 1/2% Senior Subordinated Notes to reduce indebtedness under the term loan. In July 2003, we repaid the remaining $160 million balance of this term credit facility with proceeds from our issuance of $250 million 6 1/4% 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 8 1/2% 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%.

Argo Term Loan

This loan with a balance of $95 million, including current maturities, at December 31, 2001, was repaid in full in April 2002, in connection with the EPN Holding assets acquisition.

SENIOR NOTES

In July 2003, we issued $250 million in aggregate principal amount of 6 1/4% 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. Our senior notes are guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries.

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 of our existing and future senior debt, including our existing credit facility and the senior notes we issued in July 2003.

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

In March 2003, we issued $300 million in aggregate principal amount of

8 1/2% 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, and in December 2003, we redeemed $45 million under this provision (see discussion below). We may redeem all or part of the remainder 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 November 2002, we issued $200 million in aggregate principal amount of 10 5/8% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in December 2012. These notes were issued for $198 million, net of discount of $1.5 million to yield 10.75% (proceeds of $194 million, net of issuance costs) which we used to fund a portion of the acquisition of the San Juan assets. We may, at our option, prior to December 1, 2005, redeem up to 33 percent of the originally issued aggregate principal amount of the notes at a redemption price of 110.625%, and in December 2003, we redeemed $66 million under this provision (see discussion below). On or after December 1, 2007, we may redeem all or part of the remainder of these notes at 105.313% of the principal amount.

In May 2002, we issued $230 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature June 2011. The Senior Subordinated Notes were issued for $234.6 million (proceeds of approximately $230 million, net of issuance costs). We used proceeds of $225 million to reduce indebtedness under our EPN Holding term credit facility and the remainder for general partnership purposes. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%, and in December 2003, we redeemed $75.9 million under this provision (see discussion below). On or after June 1, 2006, we may redeem all or part of the remainder of these notes at 104.250% of the principal amount.

In May 2001, we issued $250 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in June 2011. Proceeds of approximately $243 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%, and in December 2003, we redeemed $82.5 million under this provision (see discussion below). On or after June 1, 2006, we may redeem all or part of the remainder of these notes at 104.250% of the principal amount.

In May 1999, we issued $175 million in aggregate principal amount of 10 3/8% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in June 2009. Proceeds of approximately $169 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. On or after June 1, 2004, we may redeem all or part of these notes at 105.188% of the principal amount.

Our subsidiaries, except GulfTerra Energy Partners Finance Corporation and our unrestricted subsidiaries, have guaranteed our obligations under the senior notes and all of the issuances of senior subordinated notes described above. In addition, we could be required to repurchase the senior notes and senior subordinated notes if certain circumstances relating to change of control or asset dispositions exist.

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 of our 8 1/2%

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GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8 1/2%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. At December 31, 2003, the fair value of the swap was a liability, included in non-current liabilities, of approximately $7.4 million. The fair value of the hedged debt decreased by the same amount.

In December 2003, we used a portion of the net proceeds from our October 2003 equity offerings to redeem approximately $269.4 million in principal amount of our senior subordinated notes. The terms of our indentures allow us to use proceeds from an equity offering, within a 90 day period after the offering, to redeem up to 33 percent of the principal during the first three years the notes are outstanding. We incurred additional costs totaling $29.1 million resulting from the payment of the redemption premiums and the write-off of unamortized debt issuance costs, premiums and discounts. We accounted for these costs as an expense during the fourth quarter of 2003 in accordance with the provisions of SFAS No. 145.

In March 2004, we gave notice to exercise our right, under the terms of our senior subordinated notes' indentures, to repay, at a premium, approximately $39.1 million in principal amount of those senior subordinated notes. The indentures provide that, within 90 days of an equity offering, we can call up to 33 percent of the original face amount at a premium. The amount we can repay is limited to the net proceeds of the offering. We will recognize additional costs totaling $4.1 million resulting from the payment of the redemption premiums and the writeoff of unamortized debt issuance costs. We will account for these costs as an expense during the second quarter of 2004 in accordance with the provisions of SFAS No. 145.

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

As of December 31, 2003, Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, was party to a $185 million credit agreement under which it had $123 million outstanding at December 31, 2003.

In January 2004, Poseidon amended its credit agreement and decreased the availability to $170 million. The amended facility matures in January 2008. The outstanding balance from the previous facility was transferred to the new facility.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of the $123 million outstanding under its credit facility at 3.49% through January 2004. Poseidon, under its credit facility, currently pays an additional 1.25% over the LIBOR rate resulting in an effective interest rate of 4.74% on the hedged notional amount. The interest rates Poseidon is charged on balances outstanding under its credit facility are dependent on its leverage ratio as defined in the Poseidon credit facility. Poseidon's interest rate at December 31, 2003 was LIBOR plus 1.25% for Eurodollar

loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 0.25% for Base Rate loans. As of December 31, 2003, the remaining $48 million was at an average interest rate of 2.46%.

Under its amended credit facility, based on Poseidon's leverage ratio for the year ended December 31, 2003, Poseidon's interest rate is LIBOR plus 2.00% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 1.00% for Base Rate loans. Poseidon's interest rates will decrease by 0.25% if their leverage ratio declines to 3.00 to 1.00 or less, by 0.50% if their leverage ratio declines to 2.00 to 1.00 or less, or by 0.625% if their leverage ratio declines to 1.00 to 1.00 or less. Additionally, Poseidon pays commitment fees on the unused portion of the credit facility at rates that vary from 0.25% to 0.375%. This credit agreement requires Poseidon to maintain a debt service reserve equal to two times the previous quarters' interest.

Poseidon's credit agreement contains covenants such as restrictions on debt levels, restrictions on liens collateralizing debt and guarantees, restrictions on mergers and on the sales of assets and dividend restrictions. A breach of any of these covenants could result in acceleration of Poseidon's debt and other financial obligations.

Under the Poseidon $170 million revolving credit facility, the financial debt covenants are:

(a) Poseidon must maintain consolidated tangible net worth in an amount not less than $75 million plus 100% of the net cash proceeds from the issuance by Poseidon of equity securities of any kind;

(b) the ratio of Poseidon's EBITDA, as defined in Poseidon's credit agreement, to interest expense paid or accrued during the four quarters ending on the last day of the current quarter must be at least 2.50 to 1.00; and

(c) the ratio of total indebtedness of Poseidon to EBITDA for the four quarters ending on the last day of the current quarter shall not exceed 4.50 to 1.00 in 2004, 3.50 to 1.00 in 2005 and 3.00 to 1.00 thereafter.

Poseidon was in compliance with the above covenants and the covenants under its previous facility as of December 31, 2003.

Deepwater Gateway

In August 2002, Deepwater Gateway, our joint venture that is constructing the Marco Polo TLP, obtained a $155 million project finance loan from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. Deepwater Gateway may elect that all or a portion of the project finance loan bear interest at either (i) LIBOR plus 1.75% or (ii) an alternate base rate (equal to the greater of the prime rate, the base CD rate plus 1% or the federal funds rate plus 0.5%, as those terms are defined in the project finance loan agreement) plus 0.75%. Deepwater Gateway must also pay commitment fees of 0.375% per year on the unused portion of the project finance loan. The loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the project finance loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2003, Deepwater Gateway had $155 million outstanding under the project finance loan at an average interest rate of 2.94% and had not paid us or any of our subsidiaries any distributions.

This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. Upon conversion of the project finance loan to a term loan, Deepwater Gateway will be required to maintain a debt service reserve of not less than the projected principal, interest and fees due on the term loan for the immediately succeeding six month period. In addition,

Deepwater Gateway is prohibited from making distributions until the project finance loan has been repaid or is converted.

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 3 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 December 31, 2003, Cameron Highway had $69 million outstanding under the construction loan at an average interest rate of 4.21%.

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 December 31, 2003, Cameron Highway had $56 million outstanding under the notes at an average interest rate of 7.38%.

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 collateralized 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 3, 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 (in thousands):

2004	$ 3,000
2005	3,000
2006	385,000
2007	3,000
2008	288,000
Thereafter	1,135,600
Total long-term debt and other financing obligations, including current maturities	$1,817,600

INTEREST AND DEBT EXPENSE

We recognized the interest cost incurred in connection with our financing transactions as follows for each of the years ended December 31:

	2003	2002	2001

	(IN THOUSANDS)		
Interest expense incurred	$140,282	$87,522	$ 54,885
Interest capitalized	(12,452)	(5,571)	(11,755)
Net interest expense	127,830	81,951	43,130
Less: Interest expense on discontinued operations	--	891	1,588
Net interest expense on continuing operations	$127,830	$81,060	$ 41,542

LOSS DUE TO EARLY REDEMPTIONS OF DEBT

We recognized losses associated with early redemptions of debt as follows for each of the years ended December 31:

	2003	2002
	(IN THOUSANDS)	
Loss due to payment of redemption premiums	$24,302	$ --
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	12,544	2,434
	$36,846	$2,434

7. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The carrying amounts and estimated fair values of our financial instruments at December 31 are as follows:

	2003		2002	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR V
		(IN MILLIONS)		
Liabilities:				
Revolving credit facility	$382.0	$382.0	$491.0	$491
GulfTerra Holding term credit facility	--	--	160.0	160
Senior secured term loan	300.0	300.0	160.0	160
Senior secured acquisition term loan	--	--	237.5	237
10 3/8% senior subordinated notes	175.0	189.9	175.0	186
8 1/2% senior subordinated notes(1)	167.5	188.4	250.0	233
8 1/2% senior subordinated notes(1)	156.6	173.4	234.3	214
10 5/8% senior subordinated notes	133.1	165.5	198.5	205
8 1/2% senior subordinated notes	255.0	290.7	--	
6 1/4% senior notes	250.0	262.5	--	
Non-trading derivative instruments				
Commodity swap and forward contracts	$ 9.0	$ 9.0	$ 4.7	$ 4
Interest rate swap	7.4	7.4	--	

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(1) Excludes market value of interest rate swap, see interest rate swap discussion below.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

The notional amounts and terms of the financial instruments held for purposes other than trading were as follows at December 31:

	2003			2002		
	NOTIONAL VOLUME			NOTIONAL VOLUME		
	BUY	SELL	MAXIMUM TERM IN YEARS	BUY	SELL	MAXIMUM TERM IN YE
Commodity						
Natural Gas (MDth).....................	85	10,980				