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

FORM 8-K/A

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

DATE OF REPORT: JANUARY 2, 2003
(DATE OF EARLIEST EVENT REPORTED: FEBRUARY 19, 2002)

COMMISSION FILE NUMBER 1-11680

EL PASO ENERGY PARTNERS, L.P.
(Exact name of Registrant as Specified in its Charter)

DELAWARE (State or Other Jurisdiction of Incorporation or Organization)	76-0396023 (I.R.S. Employer Identification No.)
EL PASO BUILDING 4 GREENWAY PLAZA HOUSTON, TEXAS (Address of Principal Executive Offices)	77046 (Zip Code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE:
(832) 676-2600

ITEM 5. OTHER EVENTS

This Form 8-K/A is furnished to incorporate Amendment No. 1 to El Paso Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2001 (the "Original 10-K") into the Form 8-K/A filed July 19, 2002, which was filed to conform our historical financial information as of December 31, 2001 and 2000 and for the years ended December 31, 2001, 2000 and 1999 to the discontinued operations presentation and to the changes in our segment presentation made in our Form 10-Q for the quarterly period ended March 31, 2002. Amendment No. 1 to the Original 10-K was filed to amend the disclosure in "Oil and Natural Gas Production -- Net Production Unit Prices and Production Costs" in Item 1, Business and "Note 16-Supplemental Oil and Natural Gas Information (Unaudited)" in Item 8, Financial Statements and Supplemental Data, to present consistent information relating to our oil and natural gas producing activities effected by inter-segment platform access fees, which are eliminated in consolidation. There were no changes to our balance sheet, income statement, or statement of cash flows. This 8-K/A includes the amendment to "Note 16 -- Supplemental Oil and Natural Gas Information (Unaudited)." The changes primarily impact our standardized measure of discounted future net cash flows disclosure. All other information included in the Form 8-K/A filed July 19, 2002, remains unchanged.

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

/d	= per day	Mcf	= thousand cubic feet
Bbl	= barrel	MDth	= thousand dekatherms
BBtu	= billion British thermal units	MMBbls	= million barrels
Bcf	= billion cubic feet	MMBtu	= million British thermal units
Dth	= dekatherm	MMcf	= million cubic feet
MBbls	= thousand barrels	MMDth	= million dekatherms

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

YEAR ENDED DECEMBER 31,	2001	2000	1999
Operating revenues			
Natural gas pipelines and plants	$100,085	$ 63,499	$ 20,282
Oil and NGL logistics	32,925	8,307	2,029
Platform services	15,385	13,875	11,383
Natural gas storage	19,373	6,182	--
Other	25,638	20,552	29,965
	193,406	112,415	63,659
Operating expenses			
Cost of natural gas	51,542	28,160	--
Operation and maintenance, net	33,279	14,461	22,402
Depreciation, depletion and amortization	34,778	27,743	30,630
Asset impairment charge	3,921	--	--
	123,520	70,364	53,032
Operating income	69,886	42,051	10,627
Other income (loss)			
Earnings from unconsolidated affiliates	8,449	22,931	32,814
Net (loss) gain on sale of assets	(11,367)	--	10,103
Other income	28,726	2,377	358
	25,808	25,308	43,275
Income before interest, income taxes and other charges	95,694	67,359	53,902
Interest and debt expense	41,542	46,820	35,323
Minority interest	100	95	197
Income tax benefit	--	(305)	(435)
	41,642	46,610	35,085
Income from continuing operations	54,052	20,749	18,817
Income (loss) from discontinued operations	1,097	(252)	--
Net income	$ 55,149	$ 20,497	$ 18,817
Income (loss) allocation			
Series B unitholders	$ 17,228	$ 5,668	$ --
General partner			
Continuing operations	$ 24,650	$ 15,581	$ 12,129
Discontinued operations	11	(3)	--
Cumulative effect of accounting change	--	--	15,427
	$ 24,661	$ 15,578	$ 27,556
Limited partners			
Continuing operations	$ 12,174	$ (500)	$ 6,688
Discontinued operations	1,086	(249)	--
Cumulative effect of accounting change	--	--	(15,427)
	$ 13,260	$ (749)	$ (8,739)
Basic and diluted earnings per unit			
Continuing operations	$ 0.35	$ (0.02)	$ 0.26
Discontinued operations	0.03	(0.01)	--
Cumulative effect of accounting change	--	--	(0.60)
Net income (loss)	$ 0.38	$ (0.03)	$ (0.34)

Weighted

average number of units outstanding...............
34,376 29,077 25,928 ======== ======== ========

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS)

DECEMBER 31,	2001	2000
ASSETS		
Current assets		
Cash and cash equivalents	$ 13,084	$ 20,281
Accounts receivable, net		
Trade	33,162	33,801
Affiliates	22,863	1,602
Other current assets	557	633
Total current assets	69,666	56,317
Property, plant and equipment, net	917,867	497,746
Assets held for sale, net	185,560	121,492
Investment in processing agreement	119,981	--
Investments in unconsolidated affiliates	34,442	182,734
Other noncurrent assets	29,754	11,182
Total assets	$1,357,270	$869,471
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	$ 14,987	$ 14,726
Affiliates	9,918	2,368
Accrued interest	6,401	3,107
Current maturities of limited recourse term loan	19,000	--
Other current liabilities	4,159	2,171
Total current liabilities	54,465	22,372
Revolving credit facility	300,000	318,000
Long-term debt	425,000	175,000
Limited recourse term loan, less current maturities	76,000	45,000
Other noncurrent liabilities	1,079	394
Total liabilities	856,544	560,766
Commitments and contingencies		
Minority interest	--	(2,366)
Partners' capital		
Limited partners		
Series B preference units; 125,392 units in 2001 and 170,000 units in 2000 issued and outstanding	142,896	175,668
Common units; 39,738,974 units in 2001 and 31,550,314 units in 2000 issued and outstanding	354,019	132,802
Accumulated other comprehensive income allocated to limited partners' interest	(1,259)	--
General partner	5,083	2,601
Accumulated other comprehensive income allocated to general partner's interests	(13)	--
Total partners' capital	500,726	311,071
Total liabilities and partners' capital	$1,357,270	$869,471

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Cash flows from operating activities			
Net income	$ 55,149	$ 20,497	$ 18,817
Less income (loss) from discontinued operations	1,097	(252)	--
Income from continuing operations	54,052	20,749	18,817
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	34,778	27,743	30,630
Net loss (gain) on sale of assets	11,367	--	(10,103)
Asset impairment charge	3,921	--	--
Undistributed earnings from unconsolidated affiliates	(8,449)	(22,931)	(32,814)
Distributions from unconsolidated affiliates	35,062	33,960	46,180
Litigation reserve	--	(2,250)	2,250
Other noncash items	4,308	2,237	1,834
Working capital changes, net of effects of acquisitions and noncash transactions			
Accounts receivable	(41,954)	(17,351)	2,107
Other current assets	125	1,295	366
Accounts payable, accrued interest and other current liabilities	(259)	5,210	(8,507)
Noncurrent receivable from El Paso Corporation	(10,362)	--	--
Other	(173)	--	--
Net cash provided by continuing operations	82,416	48,662	50,760
Net cash provided by (used in) discontinued operations	4,968	(252)	--
Net cash provided by operating activities	87,384	48,410	50,760
Cash flows from investing activities			
Acquisition and development of oil and natural gas properties	(2,018)	(172)	(3,218)
Additions to pipelines, platforms and facilities	(508,347)	(1,849)	(30,662)
Investments in unconsolidated affiliates	(1,487)	(8,979)	(59,348)
Cash paid for acquisitions, net of cash acquired	(28,414)	(26,476)	(20,351)
Proceeds from sale of assets	109,126	--	26,122
Distributions related to the formation of Deepwater Holdings	--	--	20,000
Other	--	(381)	322
Net cash used in investing activities of continuing operations	(431,140)	(37,857)	(67,135)
Net cash used in investing activities of discontinued operations	(68,560)	(88,356)	--
Net cash used in investing activities	(499,700)	(126,213)	(67,135)
Cash flows from financing activities			
Net proceeds from revolving credit facility	559,994	152,043	141,126
Repayments of revolving credit facility	(581,000)	(125,000)	(226,850)
Net proceeds from issuance of long-term debt	243,032	--	168,878
Net proceeds from issuance of common units	286,699	100,634	--
Redemption of Series B preference units	(50,000)	--	--
Redemption of publicly held preference units	--	(804)	--
Contributions from general partner	2,843	2,785	603

Distributions to partners	(106,409)	(79,330)	(66,288)
Net cash provided by financing activities of continuing operations	355,159	50,328	17,469
Net cash provided by financing activities of discontinued operations	49,960	43,554	--
Net cash provided by financing activities	405,119	93,882	17,469
Net (decrease) increase in cash and cash equivalents	(7,197)	16,079	1,094
Cash and cash equivalents at beginning of year	20,281	4,202	3,108
Cash and cash equivalents at end of year	$ 13,084	$ 20,281	$ 4,202

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(IN THOUSANDS)

	SERIES B PREFERENCE UNITS	SERIES B PREFERENCE UNITHOLDERS	PREFERENCE UNITS	PREFERENCE UNITHOLDERS	COMMON UNITS	COMMON UNITHOLDERS	GENERAL PARTNER(1)	TOTAL
Partners' capital at December 31, 1998........	--	$ --	1,017	$ 7,351	23,350	$ 90,972	$(15,427)	$ 82,896
Cumulative effect of accounting change........	--	--	--	3,072	--	(18,499)	15,427	--
Net income(2).............	--	--	--	919	--	5,769	12,129	18,817
Acquisition of additional interest in Viosca Knoll....................	--	--	--	--	2,662	59,792	--	59,792
General partner contribution related to issuance of common units....................	--	--	--	--	--	--	603	603
Conversion of preference units into common units....................	--	--	(727)	(7,454)	727	7,454	--	--
Cash distributions.........	--	--	--	(919)	--	(52,211)	(12,489)	(65,619)
Partners' capital at December 31, 1999........	--	--	290	2,969	26,739	93,277	243	96,489
Net income (loss)(2).......	--	5,668	--	241	--	(990)	15,578	20,497
Conversion of preference units into common units....................	--	--	(211)	(2,165)	211	2,165	--	--
Redemption of remaining preference units.........	--	--	(79)	(804)	--	--	--	(804)
Issuance of common units...	--	--	--	--	4,600	100,634	--	100,634
General partner contribution related to the issuance of common units....................	--	--	--	--	--	--	2,785	2,785
Issuance of Series B preference								

units......... 170
170,000 -- -- -- -- --
170,000 Cash
distributions.........
(241) -- (62,284)
(16,005) (78,530) ------
- -------- ------- -----
---- ------- -------- --
------ ---------
Partners' capital at
December 31,
2000........ 170 175,668
-- -- 31,550 132,802
2,601 311,071 Net
income(2)..............
-- 17,228 -- -- --
13,260 24,661 55,149
Accumulated other
comprehensive income
(loss)...................
-- -- -- -- -- (1,259)
(13) (1,272) Issuance of
common units... -- -- --
-- 8,189 286,699 --
286,699 Unamortized unit
option
compensation.............
-- -- -- -- -- 2,161 --
2,161 Redemption of
Series B preference
units......... (45)
(50,000) -- -- -- -- --
(50,000) General partner
contribution related to
the issuance of common
units...................
-- -- -- -- -- -- 2,843
2,843 Cash
distributions......... -
- -- -- -- -- (80,903)
(25,022) (105,925) -----
-- -------- ------- ----
----- ------- -------- -
------- ---------
Partners' capital at
December 31,
2001........ 125
$142,896 -- $ -- 39,739
$352,760 $ 5,070 $
500,726 ======= =======
======= =========
======= ========
======== =========

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(1) El Paso Energy Partners Company, a wholly owned subsidiary of El Paso Corporation, owns a one percent general partner interest in us.
(2) Income allocation to our general partner includes both its incentive distributions and its one percent ownership interest.

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Net income	$55,149	$20,497	$18,817
Other comprehensive income (loss)	(1,272)	--	--
Total comprehensive income	$53,877	$20,497	$18,817

ACCUMULATED OTHER COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Beginning balance	$ --	$ --	$ --
Unrealized mark-to-market losses arising during period	(1,682)	--	--
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	410	--	--
Ending balance	$(1,272)	$ --	$ --

See accompanying notes.

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, 2001, we had 39,738,974 common units representing limited partner interests and 125,392 Series B preference units representing preference interests outstanding. On that date, the public owned 29,308,140 common units, or 74 percent of our outstanding common units, and El Paso Corporation, through its subsidiaries, owned 10,430,834 common units, or 26 percent of our outstanding common units, all of the 125,392 Series B preference units (with a liquidation value of $143 million) and our one percent general partner interest.

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 interests. 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 all periods presented. See Note 18 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 High Island Offshore System (HIOS) interstate natural gas system and our Petal storage facility are subject to the jurisdiction of the Federal Energy Regulatory Commission (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 Standard (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, and other costs and taxes included in, or expected to be included in, future rates.

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 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 which may become uncollectible. Collectibility is reviewed regularly and the allowance is adjusted as necessary, primarily under the specific identification method. At December 31, 2001 and 2000, the allowance was $1.8 and $0.4 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 fuel gas and unaccounted for gas tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure. Gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our financial statements.

Property, Plant and Equipment

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.

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

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

Repair and maintenance costs are expensed as incurred, while additions, improvements and replacements are capitalized.

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.

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.

Asset Impairment

We evaluate the impairment of assets in accordance with SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of. If an adverse event or change in circumstances occurs, we make an estimate of our future cash flows from our assets, grouped together at the lowest level for which separate cash flows can be measured, to determine if the asset is impaired. If the total of the undiscounted future cash flows is less than the carrying amount for the assets, we calculate the fair value of the assets either through reference to similar asset sales, or by estimating the fair value using a discounted cash flow approach. These cash flow estimates require us to make estimates and assumptions for many years into the future for pricing, demand, competition, operating costs, legal, regulatory and other factors. On January 1, 2002, we adopted the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. A discussion of this pronouncement follows at the end of this note.

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.

Revenue Recognition

Revenue from pipeline transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from natural gas sales is recognized upon delivery and was $59.7 million and $34.5 million for the years ended December 31, 2001 and 2000. There were no natural gas sales in 1999. Natural gas sales are included in gathering and transportation services revenue on the accompanying statements of income. Natural gas storage revenues and platform access revenues consist primarily of fixed fees for capacity reservation and some of our 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 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.

Environmental Costs

Expenditures for ongoing compliance with environmental regulations that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated.

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 use derivative instruments to manage these risks. Beginning in 2001, we record all derivative instruments on the balance sheet at their fair value under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities.

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.

During 2001, we entered into cash flow hedges that qualify for 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.

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, changes in their fair value are recorded in earnings in the current period.

In 1999 and 2000, we entered into commodity price swap instruments for non-trading purposes to manage our exposure to price fluctuations on anticipated natural gas and crude oil sales transactions. To qualify for hedge accounting, prior to our adoption of SFAS No. 133, the transactions must have reduced the price risk of the underlying hedged items, be designated as hedges at inception, and resulted in cash flows and financial impacts which were inversely correlated to the position being hedged. If correlation ceased to exist, hedge accounting was terminated and mark-to-market accounting was applied. Gains and losses resulting from hedging activities and the termination of any hedging instruments were initially deferred and included as an increase or decrease to oil and natural gas sales in the period in which the hedged production was sold.

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.

Income Taxes

As of December 31, 2001, neither we nor any of our subsidiaries are taxable entities. Tarpon Transmission Company, our only taxable entity in 2000 and 1999, was sold in January 2001, and as a result, we incurred no tax liability in 2001. 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.

We utilized SFAS No. 109, Accounting for Income Taxes, to account for Tarpon's income taxes subject to federal corporate income taxation. The income tax benefit reported in our consolidated statements of income for the years ended 2000 and 1999 relates solely to Tarpon's book loss at the effective statutory income tax rate for the respective period since no material differences exist between book and taxable income. In January 2001, we sold our interest in Tarpon as a result of a Federal Trade Commission (FTC) order. All of Tarpon's deferred tax liabilities were assumed by the buyer at the time of sale.

Income (Loss) per Unit

Basic income (loss) per unit excludes dilution and is computed by dividing net income (loss) attributable to the limited partners by the weighted average number of common units outstanding during the period. Diluted income (loss) per unit reflects potential dilution and is computed by dividing net income (loss) attributable to the limited partners 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 unit and diluted income (loss) per unit are the same for the years ended December 31, 2001, 2000, and 1999, 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. We include the outstanding publicly held preference units in 1999 and 2000 in the basic and diluted net income (loss) per unit calculation as if the publicly held preference units had been converted into common units. As of October 2000, all publicly held preference units have been converted into common units or redeemed.

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 at El Paso Interstate Alabama (EPIA).

Unit-Based Compensation

We apply the provisions of Accounting Principles Board Opinion (APB) No. 25 and related interpretations in accounting for unit options issued to former employees of our general partner and our board of directors. Accordingly, compensation expense is not recognized for these unit options unless the options were granted at an exercise price lower than the market price of common units on the grant date. We use fixed plan accounting for our restricted unit grants. We apply the provisions of SFAS No. 123, Accounting for Stock-Based Compensation, for unit options issued to employees of affiliates of our general partner. For these options, we amortize the fair value of these options as of the grant date over the vesting period of the grant.

Cumulative Effect of Accounting Change

In the fourth quarter of 1999, we changed our method of allocating net income to our partners' capital accounts from a method where we allocated income based on percentage ownership and proportionate share of cash distributions, to a method where income is allocated to the partners based upon the change from period to period in their respective claims on our book value capital. We believe that the new income allocation method is preferable because it more accurately reflects the income allocation provisions called for under the partnership agreement and the resulting partners' capital accounts are more reflective of a partner's claim on our book value capital at each period end. This change in accounting had no impact on our consolidated net income or our consolidated total partners' capital for any period presented. This change did not impact the declaration of distributions or the individual partner tax basis.

The impact of this change in accounting has been recorded as a cumulative effect adjustment in our income allocation for the year ended December 31, 1999. The effect of adopting this change in accounting, excluding the cumulative adjustment, was to reduce basic and diluted net income per limited partner unit by $0.33 for the year ended December 31, 1999.

Business Combinations

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, Business Combinations. This statement requires that all transactions that fit the definition of a business combination be accounted for using the purchase method and prohibits the use of the pooling of interests method for all business combinations initiated after June 30, 2001. This statement also established specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary item. The accounting for any business combination we undertake in the future will be impacted by this standard. We adopted the provisions of this standard and applied them to each of our acquisitions initiated after June 30, 2001. For transactions initiated prior to June 30, 2001, we applied the provisions of APB Opinion No. 16. Our adoption of SFAS No. 141 did not have a material effect on our financial position or results of operations.

Goodwill and Other Intangible Assets

On January 1, 2002, we adopted SFAS No. 142, Goodwill and Other Intangible Assets. Our adoption of this standard did not have a material effect on our financial statements.

Accounting for Asset Retirement Obligations

In July 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

Accounting for the Impairment or Disposal of Long-Lived Assets

In October 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. This statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of this statement are effective for fiscal years beginning after December 15, 2001. The provisions of this pronouncement will impact any asset dispositions we make after January 1, 2002, including our pending sale of the Prince TLP and the 9 percent overriding royalty interest in the Prince Field.

2. OTHER ACQUISITIONS AND DISPOSITIONS

Midstream Businesses

In February 2002, we agreed to acquire midstream businesses from El Paso Corporation. The primary businesses to be acquired include:

- the 9,400 mile EPGT Texas intrastate pipeline, with a capacity of approximately 5 Bcf/d and average throughput of 3,500 MDth/d during 2001;

- 1,300 miles of gathering systems in the Permian Basin gathering system with a capacity of 465 MMcf/d and average throughput of 341 MDth/d during 2001; and

- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

Total consideration for these transactions is approximately $750 million and will include the following consideration to subsidiaries of El Paso Corporation:

- the sale of our Prince TLP and the 9 percent overriding royalty interest in the Prince Field for approximately $190 million after our repayment of the related limited recourse debt of $95 million;

- the issuance of $6 million in common units; and

- a cash payment of $554 million.

These amounts will be adjusted at closing for the value of working capital acquired or sold. We will retain third-party marketing rights for remaining platform capacity and an option to repurchase the TLP at the end of the Prince Field reserve life. We expect to finance the purchase of these businesses through debt and equity financing in accordance with our strategy to maintain a strong balance sheet. The transaction is expected to close in the first quarter of 2002 subject to receiving regulatory approvals and arranging satisfactory financing.

NGL Storage Facilities

In December 2001, we acquired Anse La Butte, a 3.2 million barrel natural gas liquids (NGL) multi-product storage facility near Breaux Bridge, Louisiana and have included it in our operating results from the date acquired. We also acquired in January 2002, a 3.3 million barrel propane storage business and complete leaching operation located in Hattiesburg, Mississippi from Suburban Propane Partners, L.P. The purchase price for these two assets was approximately $10 million.

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 also acquired 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 receive a fixed fee for each dekatherm of natural gas that we process at the Chaco plant, and we bear all costs associated with the plant's ownership and operations. El Paso Field Services personnel will continue to operate the plant. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. El Paso Field Services has the right to repurchase the Chaco Plant at the end of the lease term in October 2002 for approximately $77 million. If El Paso Field Services does not exercise this repurchase right, it must pay us a forfeiture penalty. 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 values assigned are preliminary and may be revised based on additional information. 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

EPN Texas

In February 2001, we acquired EPN 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 600 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 NGLs into ethane, propane and butane products which 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 EPN 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 twelve months ended December 31, 2001 and 2000, as if we acquired EPN Texas, the Chaco plant and the remaining 50 percent interest in Deepwater Holdings on January 1, 2000:

	2001	2000
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$269,681	$222,080
Operating income	$101,406	$ 96,197
Net income allocated to limited partners	$ 39,157	$ 15,790
Basic and diluted net income per unit	$ 1.14	$ 0.54

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, UT Offshore System (UTOS), Nautilus, Manta Ray Offshore, Nemo, Tarpon, and the Green Canyon natural gas pipeline systems, 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 statements of income.

As additional consideration for the above transactions, El Paso Corporation will make payments to us totaling $29 million. These payments will be made in quarterly installments of $2.25 million for the next three years and $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 statements of income.

Crystal Gas Storage

In August 2000, we acquired the salt dome natural gas storage businesses of Crystal Gas Storage, Inc., a subsidiary of El Paso Corporation, in exchange for $170 million of Series B 10% Cumulative Redeemable Preference Units. We accounted for the acquisition as a purchase and assigned the purchase price to the assets and liabilities acquired based upon the estimated fair value of those assets and liabilities as of the acquisition date. We have included the operating results of Crystal Gas Storage, Inc. in our consolidated financial statements from the acquisition date. The following is summary information related to the acquisition (in thousands):

Fair value of assets acquired	$170,573
Fair value of liabilities assumed	(573)
Preference units issued	$170,000

El Paso Intrastate-Alabama Pipeline System

In March 2000, we acquired EPIA from a subsidiary of El Paso Corporation for $26.5 million in cash. We accounted for the acquisition as a purchase and assigned the purchase price to the assets and liabilities acquired based upon the estimated fair value of those assets and liabilities as of the acquisition date. We have included the operating results of EPIA in our consolidated financial statements from the acquisition date. The following is summary information related to the acquisition (in thousands):

Fair value of assets acquired	$28,261
Fair value of liabilities assumed	(1,785)
Net cash paid	$26,476

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the years ended December 31, 2000 and 1999, assuming we acquired EPIA and the Crystal natural gas storage businesses on January 1, 1999:

	2000	1999
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$131,426	$105,930
Operating income	$ 45,171	$ 12,484
Net income allocated to limited partners before accounting change	$ 1,887	$ 5,406
Basic and diluted net income per unit before cumulative effect of accounting change	$ 0.06	$ 0.21

Deepwater Holdings

In June 1999, we acquired additional interests in the HIOS, UTOS and East Breaks systems through our acquisition of Natoco, Inc. and Naloco, Inc. for $51 million. As part of the transaction, we also assumed

operations of the Stingray system, the Stingray Offshore separation facility and the West Cameron dehydration facility in November 1999. The purchase price exceeded the book value of net assets acquired by approximately $48 million. This excess cost is being amortized on a straight-line basis over the estimated lives of the acquired assets, which approximates 30 years.

In September 1999, we formed Deepwater Holdings with American Natural Resources (ANR) to reorganize our interests in various joint ventures. In the transaction, both parties contributed their respective interests in various pipeline systems and facilities to Deepwater Holdings. Following this reorganization, Deepwater Holdings owns 100 percent of the East Breaks, HIOS, UTOS, and Stingray systems, along with the West Cameron dehydration facility. In exchange for our contribution, we received a 59.66 percent interest in Deepwater Holdings. We subsequently sold a 9.66 percent members' interest in Deepwater Holdings to ANR for $26.1 million to effect a 50/50 ownership position. We realized a $10.1 million gain associated with the sale. In conjunction with the transaction, we became the full operator of the UTOS, HIOS, and East Breaks systems on June 1, 2000.

In connection with its formation, Deepwater Holdings established a $175 million credit facility to:

- retire existing debt of Stingray and Western Gulf, the parent company of East Breaks and HIOS;

- fund a one-time distribution of $20 million to each of the equity partners;

- provide funds for the remaining construction costs of the East Breaks system and any future system expansions; and

- provide for other working capital needs of Deepwater Holdings.

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the year ended December 31, 1999, assuming the transactions relating to Deepwater Holdings discussed above had occurred on January 1, 1999:

	1999
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
Operating revenues	$93,071
Operating income	$39,841
Net loss allocated to limited partners before accounting change	$(7,364)
Basic and diluted net loss per unit before cumulative effect of accounting change	$ (0.28)

As a result of El Paso Corporation's January 2001 merger with The Coastal Corporation, ANR is now our affiliate and Deepwater Holdings no longer has interests in Stingray, UTOS or the West Cameron dehydration facility. As discussed earlier, we acquired the remaining 50 percent interest in Deepwater Holdings that we did not already own in October 2001.

Viosca Knoll

In June 1999, we acquired an additional 49 percent interest in Viosca Knoll from El Paso Field Services. In the transaction, El Paso Field Services contributed $33.4 million to Viosca Knoll and then sold a 49 percent interest to us in exchange for $19.9 million and 2,661,870 common units. We paid closing costs of $0.9 million in connection with the acquisition and our general partner contributed $0.6 million to us in order to maintain its one percent capital account balance. As a result of the acquisition, we began consolidating the operating results of Viosca Knoll in June 1999.

The acquisition was accounted for as a purchase and the purchase price was assigned to the assets and liabilities acquired based upon their estimated fair value as of the acquisition date. The following is summary information related to the acquisition (in thousands):

Fair value of assets acquired	$ 83,105
Cash acquired	434
Fair value of liabilities assumed	(2,962)
Total purchase price	80,577
Issuance of common units	(59,792)
Closing costs paid	(900)
Net cash paid	$ 19,885

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the year ended December 31, 1999, assuming the Viosca Knoll acquisition had occurred on January 1, 1999:

	1999
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
Operating revenues	$104,951
Operating income	$ 48,710
Net income allocated to limited partners before accounting change	$ 8,675
Basic and diluted net income per unit before cumulative effect of accounting change	$ 0.32

In September 2000, we purchased the remaining one percent of Viosca Knoll from El Paso Field Services for approximately $2.0 million bringing our total investment in Viosca Knoll to 100 percent.

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, 2001, the carrying amount of our equity investment exceeded the underlying equity in net assets by approximately $3.0 million. This difference is being amortized on a straight-line basis over the estimated life of the underlying net assets of our investment. With our adoption of SFAS No. 142 on January 1, 2002, we will no longer amortize this excess amount but will intermittently test (no less than annually) these amounts for impairment under the provisions of SFAS No. 142. Summarized financial information for these investments is as follows:

AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2001	DEEPWATER HOLDINGS(A)	POSEIDON	DIVESTED INVESTMENTS(B)	OTHER	TOTAL
	(IN THOUSANDS)				
END OF PERIOD OWNERSHIP INTEREST	100%	36%	--	50%	
OPERATING RESULTS DATA:					
Operating revenues	$ 40,933	$ 71,516	$1,982	$145	
Other income (loss)	--	394	(85)		
Operating expenses	(16,740)	(2,701)	(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)(c)	$ (9,925)	$ 18,356	$ 148	$ 25	
Adjustments(d)	--	(146)	(9)	--	
Earnings (loss) from unconsolidated affiliates	$ (9,925)	$ 18,210	$ 139	$ 25	$ 8,449
Allocated distributions	$ 12,850	$ 22,212	$ --	$ --	$35,062
FINANCIAL POSITION DATA:					
Current assets		$ 91,367		$177	
Noncurrent assets		226,570		--	
Current liabilities		80,365		33	
Long-term debt		150,000		--	

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(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, on a going forward basis 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) 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.

(d) We recorded adjustments primarily for differences from estimated year end 2000 earnings reported in our 2000 Annual Report on Form 10-K and actual earnings reported in the 2000 audited annual reports of our unconsolidated affiliates.

AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2000	DEEPWATER HOLDINGS	POSEIDON	DIVESTED INVESTMENTS(A)	OTHER	TOTAL
	(IN THOUSANDS)				
END OF PERIOD OWNERSHIP INTEREST	50%	36%	25.67%	50%	
OPERATING RESULTS DATA:					
Operating revenues	$ 67,122	$ 65,158	$ 26,478	$110	
Other income	532	639	2,301	--	
Operating expenses	(25,279)	(24,398)	(5,205)	(51)	
Depreciation	(18,138)	(10,754)	(10,363)	--	
Other expenses	(10,711)	(11,683)	(432)	(19)	
Net income	$ 13,526	$ 18,962	$ 12,779	$ 40	
OUR SHARE:					
Allocated income	$ 6,763	$ 6,826	$ 3,281	$ 20	
Adjustments(b)	507	5,892	(358)	--	
Earnings from unconsolidated affiliates	$ 7,270	$ 12,718	$ 2,923	$ 20	$22,931
Allocated distributions	$ 13,550	$ 13,532	$ 6,878	$ --	$33,960
FINANCIAL POSITION DATA:					
Current assets	$ 46,128	$125,325	$ 4,375	$111	
Noncurrent assets	237,416	239,030	247,554	--	
Current liabilities	39,962	264,776	1,423	27	
Long-term debt	157,000	--	--	--	
Other noncurrent liabilities	9,517	1,297	--	--	

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(a) 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.

(b) We recorded adjustments primarily for differences from estimated year end 1999 earnings reported in our 1999 Annual Report on Form 10-K and actual earnings reported in the 1999 audited annual reports of our unconsolidated affiliates, and for purchase price adjustments under APB Opinion No. 16, "Business Combinations." The adjustment for Poseidon primarily represents the receipt or expected receipt of insurance proceeds to offset our share of the repair costs related to the January 2000 pipeline rupture.

AS OF OR FOR THE YEAR ENDED DECEMBER 31, 1999 ----

-------------- DEEPWATER DIVESTED VIOSCA
HOLDINGS(A) POSEIDON INVESTMENTS(B) KNOLL(C) OTHER
TOTAL ----------- -------- ------------- --------
----- ------- (IN THOUSANDS) END OF PERIOD
OWNERSHIP INTEREST..................... 50% 36%
25.67% 99% 50% ======== ======== ======== =======
==== OPERATING RESULTS DATA: Operating
revenue................................. $ 59,965
$76,160 $ 26,620 $12,338 $ 35 Other
income......................................
2,203 403 2,328 31 -- Operating
expenses................................ (31,081)
(8,774) (5,164) (925) (18)
Depreciation.......................................
(13,629) (6,172) (11,195) (1,752) -- Other
expenses....................................
(2,918) (9,133) (350) (1,973) -- -------- --------
-------- ------- ---- Net
income.. $
14,540 $52,484 $ 12,239 $ 7,719 $ 17 ========
======== ======== ======= ==== OUR SHARE:
Allocated
income.................................. $ 6,591
$18,894 $ 3,142 $ 3,860 $ 8
Adjustments(d).....................................
1,173 (7) (839) -- (8) -------- -------- --------
------- ---- Earnings from unconsolidated
affiliates............ $ 7,764 $18,887 $ 2,303 $
3,860 $ -- $32,814 ======== ======== ========
======= ==== ======= Allocated
distributions........................... $ 15,601
$18,191 $ 5,906 $ 6,350 $132 $46,180 ========
======== ======== ======= ==== ======= FINANCIAL
POSITION DATA: Current
assets.................................... $
34,334 $171,720 $ 7,934 $376 Noncurrent
assets................................. 208,939
243,971 245,164 -- Current
liabilities............................... 32,727
159,359 5,157 44 Long-term
debt.................................... 122,000
150,000 -- -- Other noncurrent
liabilities...................... 41 322 -- --

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(a) Deepwater Holdings was formed in September 1999 and owned 100 percent of Stingray, HIOS, UTOS, and the West Cameron dehydration facility. The operating results are the pro forma results of Deepwater Holding and each of its subsidiaries, Stingray, HIOS, UTOS and the West Cameron dehydration facility, as if formation of Deepwater Holdings and its acquisitions of Stingray, HIOS, UTOS and the West Cameron dehydration facility had occurred January 1, 1999.
(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) The information presented for Viosca Knoll as an equity investment is through May 31, 1999. On June 1, 1999, we began consolidating the results of Viosca Knoll as a result of acquiring an additional 49 percent interest in the system.
(d) We recorded adjustments primarily for purchase price adjustments in accordance with APB Opinion No. 16, except for Stingray which resulted from changes in estimates of reserves for uncollectable revenues.

4. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

DECEMBER 31,	2001	2000
	(IN THOUSANDS)	
Property, plant and equipment, at cost		
Pipelines	$ 856,335	$239,920
Platforms and facilities	125,878	127,639
Processing plant	138,450	--
Oil and natural gas properties	125,665	123,184
Storage facilities	156,800	147,294
Construction work-in-progress	99,335	39,455
	1,502,463	677,492
Less accumulated depreciation and depletion	584,596	179,746
Total property, plant and equipment, net	$ 917,867	$497,746

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. This amount is being amortized on a straight-line basis over the life of the agreement. Under the processing agreement, all previously uncommitted volumes on El Paso Field Services' San Juan Gathering System are dedicated to the Chaco plant. As part of the agreement, natural gas delivered to the Chaco plant by El Paso Field Services will have a processing priority over other natural gas.

6. FINANCING TRANSACTIONS

In February 2002, our universal shelf registration to offer up to $1 billion of capital securities representing limited partnership interests and debt securities and related guarantees, as filed with the Securities and Exchange Commission (SEC), became effective.

Senior Subordinated Notes

In May 2001, we issued $250 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. These notes bear interest at a rate of 8 1/2% per year, 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.

In May 1999, we issued $175 million in aggregate principal amount of 10 3/8% Senior Subordinated Notes. These notes bear interest at a rate of 10 3/8% per annum, 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.

Our subsidiaries, except Argo and Argo I L.L.C., have guaranteed our obligations under both issuances of senior subordinated notes. In addition, we could be required to repurchase the senior subordinated notes if certain circumstances relating to change of control or asset dispositions exist. The terms of the senior subordinated notes include, among other things, financial tests and covenants, all of which we currently meet.

Revolving Credit Facility

In May 2001, we amended and restated our revolving credit facility with a syndicate of commercial banks to provide up to $600 million of available credit subject to compliance with financial ratios as specified in the agreement. As of December 31, 2001, we had $300 million outstanding under this facility with the full unused amount available. The average variable interest rate on the debt outstanding was 3.9% and 9.1% at December 31, 2001 and 2000. We pay a variable commitment fee on the unused portion of the credit facility. Our credit facility matures in May 2004; is guaranteed by us and all of our subsidiaries except for our Argo and Argo I subsidiaries; and is collateralized by our management agreement, substantially all of our assets (excluding our Argo and Argo I subsidiaries), and our general partner's one percent general partner interest in us. We may borrow money under this facility for capital expenditures, investment and working capital purposes as well as to make distributions under certain circumstances.

Limited Recourse Term Loan

In August 2000, Argo, L.L.C., one of our unrestricted subsidiaries obtained a $95 million limited recourse project finance loan from a group of commercial lenders to finance a substantial portion of the total cost of the Prince TLP, pipelines and other facilities. The Prince TLP was installed in the Prince Field in July 2001, and we placed it into service in September 2001. In accordance with its terms, the project finance loan was converted into a term loan in December 2001 and will mature in December 2006. The $95 million term loan requires us to pay interest and principal in twenty equal quarterly installments. The first principal payment is due at the end of the first quarter of 2002. The term loan is collateralized by substantially all of Argo's assets. The term loan agreement restricts Argo's ability to pay distributions to us. If Argo defaults on its payment obligations, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Argo up to $30 million. As of December 31, 2001, Argo had $95 million outstanding under this limited recourse term loan and had not paid us, or any of our subsidiaries, any distributions. The average variable interest rate on the debt outstanding for 2001 and 2000 was 4.1% and 8.4% at December 31, 2001 and 2000.

Other Credit Facilities

Poseidon Oil Pipeline Company, L.L.C. is party to a credit agreement under which it has outstanding obligations that may restrict its ability to pay distributions to its owners. Deepwater Holdings, L.L.C. was a party to a credit agreement but, in conjunction with our purchase in October 2001 of the 50 percent interest that we did not already own, the $110 million balance outstanding at the acquisition date was repaid and the credit facility was terminated.

In April 2001, Poseidon amended and restated its credit facility to provide up to $185 million of the construction and expansion of the Poseidon system and for other working capital changes. Poseidon's ability to borrow money under this facility is subject to certain customary terms and conditions, including borrowing base limitations. The facility is collateralized by a substantial portion of Poseidon's assets and matures in April 2004. As of December 31, 2001, Poseidon had $150 million outstanding under its facility with the full unused balance available. The average variable floating interest rate on the debt outstanding at December 31, 2001 and 2000 was 3.8% and 7.9%. In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the interest rate at 3.49% through January 2004 on $75 million of the $150 million outstanding on their credit facility.

Interest Expense

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

	2001	2000	1999
	(IN MILLIONS)		
Interest expense incurred	$54.9	$51.1	$37.1
Interest capitalized	11.8	4.0	1.8
Net interest expense	43.1	47.1	35.3
Less: Interest expense on discontinued operations	1.6	0.3	--
Net interest expense on continuing operations	$41.5	$46.8	$35.3

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:

	2001		2000	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(IN MILLIONS)			
Liabilities:				
Revolving credit facility	$300	$300	$318	$318
Limited recourse term loan	95	95	45	45
10 3/8% Senior Subordinated Notes	175	186	175	185
8 1/2% Senior Subordinated Notes	250	253	N/A	N/A
Non-trading derivative instruments				
Commodity swap and forward contracts	$ 1	$ 1	$ --	$ --

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

	2001			2000		
	NOTIONAL VOLUME		MAXIMUM TERM IN YEARS	NOTIONAL VOLUME		MAXIMUM TERM IN YEARS
	BUY	SELL		BUY	SELL	
Commodity Natural Gas (MDth)	765	--	<1	--	--	N/A

As of December 31, 2001, and 2000, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market based nature of the debt's interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues.

8. PARTNERS' CAPITAL

General

As of December 31, 2001, we had 39,738,974 common units outstanding. Common units totaling 29,308,140 are owned by the public, representing a 74 percent limited partner interest in us. As of

December 31, 2001, El Paso Corporation, through its subsidiaries, owned 10,430,834 common units, or 26 percent of our outstanding common units, 125,392 Series B preference units (with a liquidation value of $143 million) and our one percent general partner interest.

Offering of Common Units

In October 2001, we completed a offering of 5,627,070 common units, which included a public offering of 4,150,000 common units and a private offering, at the same unit price, of 1,477,070 common units to our general partner. We used the net cash proceeds of approximately $212 million to redeem 44,608 of our Series B preference units for their liquidation value of $50 million and to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $2.1 million in cash to us in order to satisfy its one percent contribution requirement.

In March 2001, we completed a public offering of 2,250,000 common units. We used the net cash proceeds of $66.6 million from the offering to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $0.7 million to us in order to satisfy its one percent capital contribution requirement.

In July 2000, we completed a public offering of 4,600,000 common units. We used the net cash proceeds of $101 million to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $1.1 million to us in order to satisfy its one percent capital contribution requirement.

Conversion and Redemption of Preference Units

In May 1998, 1999 and 2000, we notified the holders of our publicly-held preference units of their opportunity to convert their preference units into an equal number of common units. Total preference units of 211,249 were converted to common units after the 90-day conversion period in 2000 and 78,450 preference units remained. In October 2000, we redeemed the remainder of these preference units for approximately $0.8 million representing a cash price of $10.25 per unit. For the converted units, we reallocated the partners' capital accounts in the conversion period to reflect these conversions of preference units into common units.

Series B Preference Units

In August 2000, we issued $170 million of Series B preference units to acquire the natural gas storage businesses of Crystal Gas Storage, Inc. These newly issued preference units are non-voting and have rights to income allocations on a cumulative basis, compounded semi-annually at an annual rate of 10%. We are not obligated to pay cash distributions on these units until 2010. After September 2010, the rate will increase to 12% and preference income allocation after 2010 will be required to be paid on a current basis; accordingly, after September 2010, we will not be able to make distributions on our common units unless all unpaid accruals occurring after September 2010 on our then-outstanding Series B preference units have been paid. These preference units contain no mandatory redemption obligation, but may be redeemed at our option at any time. If our capital was ever liquidated, then these Series B preference units would have priority after our general partner, but before our outstanding common unitholders. In October 2001, we redeemed 44,608 of the Series B preference units for $50 million liquidation value including accrued distributions of approximately $5.4 million, bringing the total number of units outstanding to 125,392. As of December 31, 2001, the liquidation value of the outstanding Series B preference units was approximately $143 million.

Cash Distributions

We make quarterly distributions of 100 percent of our available cash, as defined in the partnership agreement, to our unitholders and to our general partner. Available cash generally consists of all cash receipts plus reductions in reserves less all cash disbursements and net additions to reserves. Our general partner has broad discretion to establish cash reserves for any proper partnership purpose. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of our agreements or obligations. Beginning in the fourth quarter of 2010, any unpaid accruals on our Series B preference units occurring after September 2010 will be currently payable and must be completely paid, prior to any distributions on our common units.

Cash distributions on common units and to our general partner are discretionary in nature and are not entitled to arrearages of minimum quarterly distributions. The following table reflects our per unit cash distributions to our common unitholders and the total incentive distributions paid to our general partner during the year ended December 31, 2001:

MONTH PAID	COMMON UNIT (PER UNIT)	GENERAL PARTNER (IN MILLIONS)
February	$0.5500	$4.6
May	$0.5750	$5.8
August	$0.5750	$5.8
November	$0.6125	$8.1

In January 2002, we declared a cash distribution of $0.625 per common unit, or $33.7 million in the aggregate, which we paid on February 15, 2002.

For the year ended December 31, 2001, 2000 and 1999, we paid our general partner incentive distributions totaling $24.3 million, $15.5 million, and $12.1 million, respectively, and paid an incentive distribution of $8.6 million in February 2002.

Option Plans

In August 1998, we adopted the 1998 Omnibus Compensation Plan (Omnibus Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable officers and key management personnel. Unit options to purchase a maximum of 3 million common units may be issued pursuant to the Omnibus Plan. Unit options granted to date pursuant to the Omnibus Plan are not immediately exercisable. For unit options granted in 2001, one-half of the unit options are considered vested and exercisable one year after the date of grant and the remaining one-half of the unit options are considered vested and exercisable one year after the first anniversary of the date of grant. These unit options expire ten years from such grant date, but shall be subject to earlier termination under certain circumstances.

In August 1998, we adopted the 1998 Unit Option Plan for Non-Employee Directors (Director Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable directors. Unit options and restricted units to purchase a maximum of 100,000 of our common units may be issued pursuant to the Director Plan. Under the Director Plan, each non-employee director receives a grant of 2,500 unit options upon initial election to the Board of Directors and an annual unit option grant of 2,000 unit options and, beginning in 2001, an annual restricted unit grant equal to the director's annual retainer (including Chairman's retainers, if applicable) divided by the fair market value of the common units on the grant date upon each re-election to the Board of Directors. Each unit option that is granted will vest immediately at the date of grant and will expire ten years from such date, but will be subject to earlier termination in the event that such non-employee director ceases to be a director of our general partner for any reason, in which case the unit options expire 36 months after such date except in the case of death, in which case the unit options expire 12 months after such date. Each director receiving a grant of restricted units is recorded as a unitholder and has all the rights of a unitholder with respect to such units, including the right to distributions on those units. The restricted units are nontransferable during the director's service on the Board of Directors. The restrictions on the restricted units will end and the director will receive one common unit for each restricted unit granted upon the director's termination. The Director Plan is administered by a management committee consisting of the Chairman of the Board of directors of the general partner and such other senior officers of our general partner or its affiliates as the Chairman of the Board may designate. During 2001, we issued 4,090 shares of restricted units with a grant price of $33.00 per unit. The value of these units is determined based on the fair market value on the grant date.

The following table summarizes activity under the Omnibus Plan and Director Plan as of and for the years ended December 31, 2001, 2000 and 1999.

	2001		2000		1999	
	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	# UNITS OF UNDERLYING OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	925,500	$27.15	937,500	$27.16	933,000	$27.19
Granted	1,016,500	35.00	3,000	25.56	4,500	21.58
Exercised	307,500	27.17	--	--	--	--
Forfeited	--	--	7,500	27.19	--	--
Canceled	20,000	27.19	7,500	27.19	--	--
Outstanding at end of year	1,614,500	$32.09	925,500	$27.15	937,500	$27.16
Options exercisable at end of year	606,500	$27.22	925,500	$27.15	687,500	$27.15

The fair value of each unit option granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions:

ASSUMPTION	2001	2000	1999
Expected term in years	8	8	8
Expected volatility	27.50%	27.97%	28.70%
Expected dividends	9.55%	9.35%	9.20%
Risk-free interest rate	5.05%	5.35%	6.40%

The Black-Scholes weighted average fair value of options granted during 2001, 2000, and 1999 was $2.62, $2.63, and $3.14 per option, respectively.

Options outstanding as of December 31, 2001, are summarized below:

OPTIONS
OUTSTANDING
OPTIONS

EXERCISABLE

------- --

WEIGHTED
AVERAGE
WEIGHTED
WEIGHTED
RANGE OF
NUMBER
REMAINING
AVERAGE
NUMBER
AVERAGE
EXERCISE
PRICES
OUTSTANDING
CONTRACTUAL
LIFE
EXERCISE
PRICE
EXERCISABLE
EXERCISE
PRICE - --

--- ------
----- ----

-- -------
------- --

$19.86 to
$27.80
598,000
6.6 $27.18
598,000
$27.18
$27.80 to
$39.72
1,016,500
9.7 $34.97
8,500
$32.71 ---
------ ---

$19.86 to
$39.72
1,614,500
8.6 $32.09
606,500
$27.22
=========
=======

If the compensation expense for our stock-based compensation plans, accounted for under APB 25, had been determined applying the provisions of SFAS No. 123, Accounting for Stock Based Compensation, using the Black-Scholes weighted average fair value of options granted, our net income (loss) allocated to the limited partners and net income (loss) per common unit for 2001, 2000, and 1999 would approximate the pro forma amounts below:

	DECEMBER 31, 2001		DECEMBER 31, 2000		DECEMBER 31, 1999	
	AS REPORTED	PRO FORMA	AS REPORTED	PRO FORMA	AS REPORTED	PRO FORMA
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)					
SFAS No. 123 charge, pretax.....	$ --	$ 311	$ --	$ 211	$ --	$ 890
Net income (loss) allocated to the limited partners..........	$13,260	$12,949	$ (749)	$ (960)	$(8,739)	$(9,629)
Basic and diluted income (loss) per unit......................	$ 0.38	$ 0.38	$(0.03)	$(0.03)	$ (0.34)	$ (0.37)

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

9. RELATED PARTY TRANSACTIONS

The following table provides summary data for the income statement impacts of our transactions with related parties for the years ended December 31:

	2001	2000	1999
	(IN THOUSANDS)		
Revenues received from related parties:			
Natural gas pipelines and plants..........................	$12,674	$ 9,356	$ --
Oil and NGL logistics....................................	32,382	--	--
Platform services(1)....................................	--	146	990
Natural gas storage.....................................	2,324	1,268	--
Other(1)..	--	15,722	29,778
	$47,380	$26,492	$30,768
Expenses paid to related parties:			
Purchased natural gas costs..............................	$34,646	$16,751	$ --
Operating expenses......................................	34,499	22,817	13,494
	$69,145	$39,568	$13,494
Reimbursements received from related parties:			
Operating expenses......................................	$11,499	$20,543	$ 2,377

At December 31, 2001 and 2000, our accounts receivable balances due from related parties were approximately $22.9 million and $1.6 million. At December 31, 2001 and 2000, our accounts payable balances due to related parties were approximately $9.9 million and $2.4 million.

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(1) In addition to the revenues from continuing operations reflected above, we also received revenues from related parties of $8.2 million for our Prince

TLP and $0.7 million for our 9 percent overriding royalty interest which are included in income from discontinued operations on our income statement for 2001.

In connection with the sale of our Gulf of Mexico assets, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and $2 million in the first quarter of 2004. At December 31, 2001, the present value of the amounts due from El Paso Corporation were classified as follows:

	(IN THOUSANDS)
Accounts receivable affiliate..........................	$ 7,745
Other noncurrent assets................................	10,362

	$18,107
	=======

The following table provides summary data categorized by our related parties for the years ended December 31:

	2001	2000	1999
	-------	-------	-------
	(IN THOUSANDS)		
Revenues received from related parties:			
El Paso Corporation			
Merchant Energy North America Company..................	$ 9,865	$21,832	$29,778
El Paso Production Company(1)...........................	4,194	4,303	--
Southern Natural Gas Company...........................	156	155	--
Tennessee Gas Pipeline Company.........................	748	56	--
El Paso Field Services.................................	32,382	--	--
Unconsolidated Subsidiaries			
Manta Ray Offshore(2)..................................	35	146	--
Viosca Knoll Gathering Company(3)......................	--	--	990
	-------	-------	-------
	$47,380	$26,492	$30,768
	=======	=======	=======
Purchased natural gas costs paid to related parties:			
El Paso Corporation			
Merchant Energy North America Company..................	$28,047	$14,454	$ --
El Paso Production Company.............................	6,412	2,160	--
Southern Natural Gas Company...........................	187	137	--
	-------	-------	-------
	$34,646	$16,751	$ --
	=======	=======	=======
Operating expenses paid to related parties:			
El Paso Corporation			
El Paso Field Services.................................	$33,965	$22,265	$11,726
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company..........................	534	552	944
Viosca Knoll Gathering Company(3)......................	--	--	824
	-------	-------	-------
	$34,499	$22,817	$13,494
	=======	=======	=======
Reimbursements received from related parties:			
Unconsolidated Subsidiaries			
Deepwater Holdings(4)..................................	$ 9,399	$20,344	$ 1,820
Poseidon Oil Pipeline Company..........................	2,100	--	--
Manta Ray Offshore(2)..................................	--	199	515
Viosca Knoll Gathering Company(3)......................	--	--	42
	-------	-------	-------
	$11,499	$20,543	$ 2,377
	=======	=======	=======

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(1) In addition to revenues from continuing operations from El Paso Production Company reflected above, we also received revenues of $8.9 million from El Paso Production Company which are included in income from discontinued operations in our income statement for 2001.

(2) We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso Corporation's merger with the Coastal Corporation.

(3) With our purchase of an additional 49 percent interest in Viosca Knoll Gathering Company in 1999, we began consolidating this company into our financial statements.

(4) In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. In April 2001, Deepwater Holdings sold its UTOS subsidiary. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings, and as a result of this transaction, on a going forward basis, Deepwater Holdings is consolidated in our financial statements and our agreement with Deepwater Holdings terminated.

Revenues received from related parties

EPN Texas. In connection with our acquisition of EPN Texas in February 2001, we entered into a 20-year fee-based transportation and fractionation agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each barrel of NGL transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. For the year ended December 31, 2001, we received revenue of approximately $25.2 million related to this agreement.

Chaco processing plant. In connection with our Chaco transaction in October 2001, we entered into a 20-year fee-based processing agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each dekatherm of natural gas that we process at the Chaco plant. For the year ended December 31, 2001, we received revenue of $6.5 million related to this agreement. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. For the year ended December 31, 2001, we received $0.6 million related to this lease.

Storage facilities. Merchant Energy North America Company and Tennessee Gas Pipeline Company use our storage caverns to store gas from time to time. For the year ended December 31, 2001, and the four months ended December 31, 2000 we received approximately $1.6 million and $1.2 million from Merchant Energy North America Company for natural gas storage fees. For the year ended December 31, 2001, and the four months ended December 31, 2000 we received approximately $0.7 million and $0.1 million from Tennessee Gas Pipeline Company.

Prince TLP. In September 2001, we placed our Prince TLP in service. We receive a monthly demand charge of approximately $1.9 million as well as processing fees from El Paso Production Company related to production on the Prince TLP. For the four months ended December 31, 2001, we received $8.2 million in platform revenue related to this agreement. In connection with our acquisition of midstream businesses from El Paso Corporation, we agreed in February 2002 to sell our Prince TLP to subsidiaries of El Paso Corporation.

Production fields. In prior years we had agreed to sell substantially all of our oil and natural gas production to Merchant Energy North America Company on a month to month basis. The agreement provided fees equal to two percent of the sales value of crude oil and condensate and $0.015 per dekatherm of natural gas for marketing production. During the years ended December 31, 2000 and 1999, oil and natural gas sales related to this agreement totaled approximately $15.7 million and $29.8 million. Beginning in the fourth quarter of 2000, we began selling our oil and natural gas directly to third parties.

In October 1999, we farmed out our working interest in the Prince Field to El Paso Production Company. Under the terms of the farmout agreement, our net overriding royalty interest in the Prince Field increased to a weighted average of approximately nine percent. El Paso Production Company began production on the Prince Field in September 2001. For the year ended December 31, 2001, we recorded approximately $0.7 million in revenues related to our overriding royalty interest in the Prince Field. In connection with our acquisition of midstream businesses from El Paso Corporation, we agreed in February 2002 to sell our 9 percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation.

EPIA. In March 2000, we acquired EPIA. Several El Paso Corporation subsidiaries buy and transport natural gas on our EPIA system. For the years ended December 31, 2001 and 2000, we received approximately $8.3 million and $4.9 million from Merchant Energy North America Company. For the years ended December 31, 2001 and 2000, we received approximately $4.2 million and $4.3 million from El Paso Production Company. For the years ended December 31, 2001 and 2000, we received approximately $0.2 million and $0.2 million from Southern Natural Gas Company.

Unconsolidated Subsidiaries. For the years ended December 31, 2001 and 2000, we received approximately $0.03 million and $0.1 million from Manta Ray Offshore Gathering as platform access and processing fees related to our South Timbalier 292 platform and our Ship Shoal 332 platform. For the five months ended May 31, 1999, we received from Viosca Knoll Gathering Company approximately $1.0 million for expenses and platform fees related to our Viosca Knoll 817 platform.

Expenses paid to related parties

Purchased natural gas costs. EPIA's purchases of natural gas include transactions with affiliates of our general partner. For the years ended December 31, 2001 and 2000, we had natural gas purchases of approximately $28.0 million and $14.4 million from Merchant Energy North America Company, $6.4 million and $2.2 million from El Paso Production Company and $0.2 million and $0.1 million from Southern Natural Gas Company.

Operating Expenses. Substantially all of the individuals who perform the day-to-day financial, administrative, accounting and operational functions for us, as well as those who are responsible for directing and controlling us, are currently employed by El Paso Corporation. Under a management agreement between a subsidiary of El Paso Corporation and our general partner, a management fee of $775,000 per month is charged to our general partner which is intended to approximate the amount of resources allocated by El Paso Corporation in providing various operational, financial, accounting and administrative services on behalf of our general partner and us. Under the terms of the partnership agreement, our general partner is entitled to reimbursement of all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on our behalf, including, but not limited to, amounts payable by our general partner to El Paso Corporation under its management agreement. We are also charged for insurance and other costs paid directly by El Paso Field Services on our behalf. The management agreement expires on June 30, 2002, and may be terminated thereafter upon 90 days notice by either party.

As we became operator of each Deepwater Holdings subsidiary, acquired new operations or constructed new facilities, we entered into additional management and operating agreements with El Paso Field Services. All fees paid under these contracts approximate actual costs incurred.

The following table shows the amount El Paso Field Services charged us for each of our agreements for the year ended December 31:

	2001	2000	1999
	(IN THOUSANDS)		
Basic management fee	$ 9,300	$ 9,300	$ 9,300
Insurance and other costs	4,844	2,577	2,426
Deepwater Holdings operating fee	5,618	6,395	--
EPIA operating fee	3,036	2,658	--
EPN Texas operating fee	6,340	--	--
Natural gas storage facilities operating fee	4,004	1,335	--
Indian Basin lateral operating fee	823	--	--
	$33,965	$22,265	$11,726

Poseidon charges were for transportation services related to transporting production from our Garden Banks Block 72 and 117 leases. Viosca Knoll charges in 1999 were for transportation services related to transporting production from our Viosca Knoll 817 Block lease.

Cost Reimbursements. In connection with becoming the operator of Poseidon, we entered into an operating agreement in January 2001. For the years ended December 31, 2000 and 1999, we charged Manta Ray Offshore a management fee pursuant to its management and operations agreements. Under a management agreement between us and Viosca Knoll, prior to our purchase of an additional 49 percent interest in June 1999, we charged Viosca Knoll a base fee of $100,000 annually in exchange for our providing financial, accounting and administrative services on behalf of Viosca Knoll. All fees received under contracts approximate actual costs incurred.

As a result of becoming the operator of Deepwater Holdings' assets during 1999 and 2000, we began receiving reimbursement from Deepwater Holdings for the cost of operating HIOS, UTOS, East Breaks, Stingray, and the West Cameron dehydration facility. This reimbursement is a fixed monthly amount covering normal operating activities that was approved by each subsidiary's management committee and is based on historical operating expenses. We recorded these as a reduction to our operation and maintenance expense. To the extent our costs are more than the monthly reimbursement, our operating expenses will be higher, and to the extent our costs are lower than the monthly reimbursement, our operating expense will be lower. In addition, due to the timing of actual costs, we recognized fluctuations in our results of operations throughout the years.

10. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

We and our subsidiaries and affiliates are named as a defendant in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. For each of these matters, we evaluate the merits of the case, our exposure to the matter and possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we make the necessary accruals. As new information becomes available, our estimates may change. The impact of these changes may have a material effect on our results of operations. As of December 31, 2001, we had no accruals relating to legal proceedings. Below is a discussion of several of our more significant matters.

We, along with several subsidiaries of El Paso Corporation were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to under report the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties Qui Tam Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss.

We have also been named defendants in Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al, filed in 1999 in the District Court of Stevens County, Kansas. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to Kansas State Court for further proceedings. A motion to dismiss this case is pending.

While the outcome of the matters discussed above cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, operating results or cash flows.

Environmental

We are subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. We currently do not have any accruals for environmental matters.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will make accruals accordingly.

Regulatory Matters

FERC has jurisdiction over HIOS and the Petal natural gas storage facility with respect to transportation of natural gas, rates and charges, construction of new facilities, extension or abandonment of service and facilities, accounts and records, depreciation and amortization policies, and certain other matters.

HIOS and Petal are currently operating under agreements with their respective customers that provide for rates that have been approved by FERC. HIOS is required to file a rate case with FERC in 2002. Our remaining systems are gathering facilities and, as such, are not currently subject to rate and certificate regulation by FERC.

In September 2001, FERC issued a Notice of Proposed Rulemaking (NOPR) that proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since HIOS and Petal are interstate facilities as defined by the Natural Gas Act, the proposed regulations, if adopted by FERC, would dictate how HIOS and Petal conduct business and interact with all energy affiliates of El Paso Corporation and us. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place administrative and operational burdens on us. Further, more fundamental changes could be required such as a complete organizational separation or sale of HIOS and Petal.

All of our pipelines are subject to FERC's administration of the "equal access" requirements of the Outer Continental Shelf Lands Act. In addition, the Poseidon and Allegheny systems are subject to regulation under the Hazardous Liquid Pipeline Safety Act. Operations in offshore federal waters are regulated by the United States Department of the Interior.

11. ACCOUNTING FOR HEDGING ACTIVITIES

A majority of our commodity sales and purchases, which relate to sales of oil and natural gas associated with our production operations and purchases and sales of natural gas associated with our EPIA pipeline, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. On January 1, 2001, we adopted the provisions of SFAS No. 133, Accounting for Derivatives and Hedging Activities. We did not have any derivative contracts in place at December 31, 2000, and therefore, there was no transition adjustment recorded in our financial statements. During 2001, we entered into cash flow hedges. As of December 31, 2001, the fair value of these cash flow hedges included in accumulated other comprehensive income was an unrealized loss of approximately $1.3 million. We estimate the entire amount will be reclassified from accumulated other comprehensive income to earnings over the next 12 months. Reclassifications occur upon physical delivery of the hedged commodity and the corresponding expiration of the hedge. For the year ended December 31, 2001, there was no ineffectiveness in our cash flow hedges.

In January 2002, Poseidon entered into an interest rate swap to hedge a portion of its debt to reduce its exposure to fluctuations in market interest rates.

12. SUPPLEMENTAL DISCLOSURES TO THE STATEMENT OF CASH FLOWS

Cash paid for interest, net of amounts capitalized were as follows:

	YEAR ENDED DECEMBER 31, 2001	2000	1999
	(IN THOUSANDS)		
Interest	$41,020	$46,768	$31,696

Noncash investing and financing activities excluded from the statement of cash flows were as follows:

	YEAR ENDED DECEMBER 31, 2001	2000	1999
	(IN THOUSANDS)		
Acquisition of additional 50 percent interest in Deepwater Holdings			
Working capital acquired	$ 7,494	$ --	$ --
Acquisition of Crystal natural gas storage businesses			
Issuance of Series B preference units	--	170,000	--
Working capital acquired	--	220	--
Acquisition of EPIA			
Working capital acquired	--	(1,673)	--
Acquisition of additional ownership interest in Viosca Knoll			
Issuance of common units	--	--	59,792
Working capital acquired	--	--	(2,400)

13. MAJOR CUSTOMERS

The percentage of our revenue from major customers was as follows:

	YEAR ENDED DECEMBER 31, 2001	2000	1999
El Paso Field Services	16%	--	--
Alabama Gas Corporation	14%	20%	26%
Shell Offshore	--	13%	--
Kerr-McGee Corporation	--	11%	--
Shell Gas Trading Co.	--	--	21%

The 2001 percentage declines in revenue from some of our major customers in 2000 is primarily attributed to increased revenue from our 2001 operations as a result of acquisitions in 2001, principally the acquisition of the EPN Texas assets and Chaco.

14. BUSINESS SEGMENT INFORMATION:

We have revised and renamed our business segments to reflect changes in the composition of our operations as discussed below. As a result we have segregated our business activities into four distinct operating segments:

- Natural Gas Pipelines and Plants;

- Oil and NGL Logistics;

- Natural Gas Storage; and

- Platform Services.

As a result of our acquisition of EPN Texas in February 2001, we began providing NGL transportation and fractionation services and have shown these activities as a separate segment called Oil and NGL Logistics. This segment also includes the liquid transportation services of the Allegheny and Poseidon oil pipelines which were previously reflected in the Natural Gas Pipelines and Plants segment and our Chaco cryogenic gas processing plant, which we acquired in October 2001.

With the July 2001 installation of the Prince TLP facility in the Prince Field, we began managing our platform operations separately from our gathering and transportation operations. Accordingly, we have shown our platforms as a separate segment called Platform Services. This segment includes the East Cameron 373, Viosca Knoll 817, Garden Banks 72, and Ship Shoal 331 and 332 platforms which were previously reflected in the Natural Gas Pipelines and Plants segment.

As a result of our agreement to sell the Prince TLP and our 9 percent overriding royalty interest in the Prince Field to El Paso Corporation in February 2002, the results of operations from these assets are reflected as discontinued operations in our statements of income for all periods presented and are not reflected in our segment results below; nor are the related assets held for sale included in segment assets. The operations of our oil and natural gas production activities are reflected in Other. Additionally, when we acquired the Chaco processing plant in October 2001 we reflected the operations of this asset in our Oil and NGL logistics segment. In light of the expectations of acquiring additional natural gas pipeline and processing assets, effective January 1, 2002, we moved the Chaco processing plant to our Natural gas pipelines and plants segment.

We have restated the prior periods, to the extent practicable, in order to conform to the current business segment presentation. The results of operations for the restated periods are not necessarily indicative of the results that would have been achieved had the revised business structure been in effect during the period.

The accounting policies of the individual segments are the same as those described in Note 1. Since earnings from unconsolidated affiliates can be a significant component of earnings in several of our segments, we have chosen to evaluate segment operating performance based on earnings before interest and taxes (EBIT) instead of operating income. We record intersegment revenues at rates that approximate market. Each of our segments are business units that offer different services and products. They are managed separately, as each requires different technology and marketing strategies. We also measure segment performance using performance cash flows, or an asset's ability to generate cash flow. Performance cash flows should not be considered an alternate to EBIT, or other financial measures as an indicator of operating performance. The following are results as of and for the periods ended December 31:

	NATURAL GAS PIPELINES & PLANTS	OIL AND NGL LOGISTICS	NATURAL GAS STORAGE	PLATFORM SERVICES	OTHER(1)	TOTAL
FOR THE YEAR ENDED DECEMBER 31, 2001						
Revenue from external customers......	$100,085	$ 32,925	$ 19,373	$ 15,385	$ 25,638	$ 193,406
Intersegment revenue................	381	--	--	12,620	(13,001)	--
Depreciation, depletion and amortization......................	12,378	5,113	5,605	4,154	7,528	34,778
Asset impairment charge..............	3,921	--	--	--	--	3,921
Operating income (loss).............	25,789	21,547	9,548	22,686	(9,684)	69,886
Earnings (loss) from unconsolidated investments.......................	(9,761)	18,210	--	--	--	8,449
EBIT from continuing operations......	30,904	39,757	9,568	22,054	(6,589)	95,694
EBIT from discontinued operations....	--	--	--	2,896	(211)	2,685
Performance cash flows..............	51,720	52,791	15,173	32,726	9,030	161,440
Assets..............................	563,545	195,839	226,991	115,369	69,966	1,171,710
FOR THE YEAR ENDED DECEMBER 31, 2000						
Revenue from external customers......	$ 63,499	$ 8,307	$ 6,182	$ 13,875	$ 20,552	$ 112,415
Intersegment revenue................	629	--	--	12,958	(13,587)	--
Depreciation, depletion and amortization......................	8,062	1,391	1,868	4,445	11,977	27,743
Operating income (loss).............	26,183	6,876	2,190	22,491	(15,689)	42,051
Earnings from unconsolidated investments.......................	10,213	12,718	--	--	--	22,931
EBIT................................	37,004	21,322	2,193	22,491	(15,651)	67,359
Performance cash flows..............	54,823	28,528	4,061	24,686	(4,993)	107,105
Assets..............................	345,309	65,734	176,420	111,810	48,706	747,979
FOR THE YEAR ENDED DECEMBER 31, 1999						
Revenue from external customers......	$ 20,282	$ 2,029	$ --	$ 11,383	$ 29,965	$ 63,659
Intersegment revenue................	693	--	--	12,500	(13,193)	--
Depreciation, depletion and amortization......................	6,335	643	--	4,082	19,570	30,630
Operating income (loss).............	9,694	1,155	--	15,962	(16,184)	10,627
Earnings from unconsolidated investments.......................	13,927	18,887	--	--	--	32,814
EBIT................................	33,730	20,042	--	15,962	(15,832)	53,902
Performance cash flows..............	44,018	19,989	-			

- 22,294 5,004 91,305
Assets..............................
319,345 57,893 -- 123,382 82,965
583,585

- ---------------

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

(2) Performance cash flows are determined by taking EBIT and adding or subtracting, as appropriate, cash distributions from unconsolidated affiliates; depreciation, depletion and amortization; earnings from unconsolidated affiliates; and other items. The calculation of performance cash flows for the 2001 period excludes the income recognized from El Paso Corporation's additional consideration related to the sales of our Gulf of Mexico assets, losses incurred on the sales of these assets and the impairment of our Manta Ray pipeline and includes the cash payments we have received from El Paso Corporation in accordance with the sales of our Gulf of Mexico assets. The calculation of performance cash flows for the 2000 period excludes the reversal of a litigation reserve and hedging items and includes the cash received related to insurance proceeds for Poseidon's pipeline rupture. The calculation of performance cash flows for the 1999 period excludes the establishment of a litigation reserve and hedging items.

15. GUARANTOR FINANCIAL INFORMATION

In May 2001, we purchased our general partner's 1.01 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 joint ventures, are wholly owned by us. Our revolving credit facility is guaranteed by each of our subsidiaries (excluding our Argo, L.L.C. and Argo I, L.L.C. subsidiaries) and is collateralized by our management agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, all of our senior subordinated notes are guaranteed by all of our subsidiaries except Argo and Argo I.

We are providing the following condensed consolidating financial information of us (as the issuer) and our subsidiaries as if our current organizational structure were in place for all periods presented. The consolidating eliminations column on our balance sheets eliminate our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries.

Non-guarantor subsidiaries for the year ended December 31, 2001, consisted of Argo and Argo I which owned the Prince TLP. As a result of our disposal of the Prince TLP and our related overriding royalty interest in the Prince Field to El Paso Corporation in April 2002, the results of operations, cash flows and net book value of these assets are reflected as discontinued operations in our statements of income and cash flows and as assets held for sale in our balance sheets. Additionally, Argo and Argo I became guarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2001

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Operating revenues				
Natural gas pipelines and plants	$ --	$ --	$100,085	$100,085
Oil and NGL logistics	--	--	32,925	32,925
Platform services	--	--	15,385	15,385
Natural gas storage	--	--	19,373	19,373
Other	--	--	25,638	25,638
	--	--	193,406	193,406
Operating expenses				
Cost of natural gas	--	--	51,542	51,542
Operation and maintenance, net	(200)	--	33,479	33,279
Depreciation, depletion and amortization	323	--	34,455	34,778
Asset impairment charge	--	--	3,921	3,921
	123	--	123,397	123,520
Operating income (loss)	(123)	--	70,009	69,886
Other income (loss)				
Earnings from unconsolidated affiliates	--	--	8,449	8,449
Net loss on sales of assets	(10,941)	--	(426)	(11,367)
Other income	28,492	--	234	28,726
	17,551	--	8,257	25,808
Income before interest, income taxes and other charges	17,428	--	78,266	95,694
Interest and debt income (expense)	15,328	--	(56,870)	(41,542)
Minority interest	--	--	(100)	(100)
Income from continuing operations	32,756	--	21,296	54,052
Income from discontinued operations	--	1,308	(211)	1,097
Net income	$ 32,756	$ 1,308	$ 21,085	$ 55,149

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2000

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Operating revenues				
Natural gas pipelines and plants..............	$ --	$ --	$ 63,499	$ 63,499
Oil and NGL logistics........................	--	--	8,307	8,307
Platform services............................	--	--	13,875	13,875
Natural gas storage..........................	--	--	6,182	6,182
Other..	--	--	20,552	20,552
	--	--	112,415	112,415
Operating expenses				
Cost of natural gas..........................	--	--	28,160	28,160
Operation and maintenance, net................	(323)	--	14,784	14,461
Depreciation, depletion and amortization......	151	--	27,592	27,743
	(172)	--	70,536	70,364
Operating income..............................	172	--	41,879	42,051
Other income				
Earnings from unconsolidated affiliates.......	--	--	22,931	22,931
Other income..................................	311	--	2,066	2,377
	311	--	24,997	25,308
Income before interest, income taxes and other charges......................................	483	--	66,876	67,359
Interest and debt expense.....................	(70)	--	(46,750)	(46,820)
Minority interest.............................	--	--	(95)	(95)
Income tax benefit............................	--	--	305	305
Income from continuing operations	413	--	20,336	20,749
Loss from discontinued operations..............	--	(252)	--	(252)
Net income (loss)....................	$ 413	$(252)	$ 20,336	$ 20,497

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 1999

	ISSUER	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)		
Operating revenues			
Natural gas pipelines and plants	$ --	$ 20,282	$ 20,282
Oil and NGL logistics	--	2,029	2,029
Platform services	--	11,383	11,383
Other	--	29,965	29,965
	--	63,659	63,659
Operating expenses			
Operation and maintenance, net	--	22,402	22,402
Depreciation, depletion and amortization	28	30,602	30,630
	28	53,004	53,032
Operating income (loss)	(28)	10,655	10,627
Other income			
Earnings from unconsolidated affiliates	--	32,814	32,814
Net gain on sales of assets	--	10,103	10,103
Other income	218	140	358
	218	43,057	43,275
Income before interest, income taxes and other charges	190	53,712	53,902
Interest and debt expense	--	(35,323)	(35,323)
Minority interest	--	(197)	(197)
Income tax benefit	--	435	435
Net income	$190	$ 3,200	$ 18,817

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2001

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
	(IN THOUSANDS)				
Current assets					
Cash and cash equivalents	$ 7,406	$ 2,571	$ 3,107	$ --	$ 13,084
Accounts receivable, net					
Trade	--	191	32,971	--	33,162
Affiliate	970,933	2,130	2,150	(952,350)	22,863
Other current assets	2,375	264	(2,082)	--	557
Total current assets	980,714	5,156	36,146	(952,350)	69,666
Property, plant and equipment, net	2,371	--	915,496	--	917,867
Assets held for sale, net	--	152,734	32,826	--	185,560
Investment in processing agreement	--	--	119,981	--	119,981
Investments in unconsolidated affiliates	--	--	34,442	--	34,442
Investments in consolidated affiliates	51,960	--	45,849	(97,809)	--
Other noncurrent assets	196,777	1,089	1,887	(169,999)	29,754
Total assets	$1,231,822	$158,979	$1,186,627	$(1,220,158)	$1,357,270
Current liabilities					
Accounts payable					
Trade	$ 587	$ 3,859	$ 10,541	$ --	$ 14,987
Affiliate	--	13,568	948,700	(952,350)	9,918
Accrued interest	5,698	703	--	--	6,401
Current maturities of limited recourse term loan	--	19,000	--	--	19,000
Other current liabilities	(189)	--	4,348	--	4,159
Total current liabilities	6,096	37,130	963,589	(952,350)	54,465
Revolving credit facility	300,000	--	--	--	300,000
Long-term debt	425,000	--	--	--	425,000
Limited recourse term loan, less current					

maturities..............	--	76,000	--	--	76,000
Other noncurrent liabilities......	--	--	171,078	(169,999)	1,079
Partners' capital.................	500,726	45,849	51,960	(97,809)	500,726
Total liabilities and partners' capital.....	$1,231,822	$158,979	$1,186,627	$(1,220,158)	$1,357,270

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2000

(IN THOUSANDS)	ISSUER	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
Current assets					
Cash and cash equivalents	$ 18,865	$ 1,416	$ --	$ --	$ 20,281
Accounts receivable, net					
Trade	--	--	39,270	(5,469)	33,801
Affiliate	620,780	(875)	1,602	(619,905)	1,602
Other current assets	390	--	243	--	633
Total current assets	640,035	541	41,115	(625,374)	56,317
Property, plant and equipment, net	1,798	--	495,948	--	497,746
Assets held for sale, net	--	88,356	33,136	--	121,492
Investments in unconsolidated affiliates	--	--	182,734	--	182,734
Investments in consolidated affiliates	156,175	--	44,542	(200,717)	--
Other noncurrent assets	9,498	1,445	239	--	11,182
Total assets	$807,506	$90,342	$797,714	$(826,091)	$869,471
Current liabilities					
Accounts payable					
Trade	$ 1,585	$ 508	$ 18,102	$ (5,469)	$ 14,726
Affiliate	--	--	622,273	(619,905)	2,368
Accrued interest	2,815	292	--	--	3,107
Other current liabilities	(965)	--	3,136	--	2,171
Total current liabilities	3,435	800	643,511	(625,374)	22,372
Revolving credit facility	318,000	--	--	--	318,000
Long-term debt	175,000	--	--	--	175,000
Limited recourse term loan	--	45,000	--	--	45,000
Other noncurrent liabilities	--	--	394	--	394
Minority interest	--	--	(2,366)	--	(2,366)
Partners' capital	311,071	44,542	156,175	(200,717)	311,071

--- -------- --------- --------
Total liabilities and partners' capital..... $807,506 $90,342 $797,714 $(826,091) $869,471
======== ======= ======== ========= ========

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 2001

NON-GUARANTOR GUARANTOR CONSOLIDATED ISSUER
SUBSIDIARIES SUBSIDIARIES TOTAL --------- --------
----- ----------- ----------- (IN THOUSANDS)
Cash flows from operating activities Net
income..
$ 32,756 $ 1,308 $ 21,085 $ 55,149 Less income
from discontinued operations............. -- 1,308
(211) 1,097 --------- -------- --------- ---------
Income from continuing
operations................... 32,756 -- 21.296
54,052 Adjustments to reconcile net income to net
cash provided by operating activities
Depreciation, depletion and
amortization........... 323 -- 35,455 34,778 Net
loss on sales of assets.......................
10,941 -- 426 11,367 Asset impairment
charge........................... -- -- 3,921
3,921 Distributed earnings of unconsolidated
affiliates Earnings from unconsolidated
affiliates.......... -- -- (8,449) (8,449)
Distributions from unconsolidated affiliates.....
-- -- 35,062 35,062 Other noncash
items............................... 3,155 318
835 4,308 Working capital changes, net of effects
of acquisitions and non-cash
transactions............. (9,740) 385 (43,268)
(52,623) --------- -------- --------- ---------
Net cash provided by continuing
operations......... 37,435 703 44,278 82,416 Net
cash provided by discontinued operations....... --
4,296 672 4,968 --------- -------- --------- -----
---- Net cash provided by operating
activities..... 37,435 4,999 44,950 87,384 -------
-- -------- --------- --------- Cash flows from
investing activities Acquisitions and development
of oil and natural gas
properties...
-- -- (2,018) (2,018) Additions to pipelines,
platforms and facilities..... (896) -- (507,451)
(508,347) Investments in unconsolidated
affiliates............ -- -- (1,487) (1,487) Cash
paid for acquisitions, net of cash acquired..... -
- -- (28,414) (28,414) Proceeds from sale of
assets......................... 89,162 -- 19,964
109,126 --------- -------- --------- --------- Net
cash provided by (used in) investing activities of
continuing operations..........................
88,266 -- (519,406) (431,140) Net cash used in
investing activities of discontinued
operations...
-- (67,367) (1,193) (68,560) --------- -------- --
------- --------- Net cash provided by (used in)
investing
activities.................................
88,266 (67,367) (520,599) (499,700) --------- ----
---- --------- --------- Cash flows from financing
activities Net proceeds from revolving credit
facility.......... 559,994 -- -- 559,994
Repayments of revolving credit
facility............. (581,000) -- -- (581,000)
Net proceeds from issuance of long-term
debt......... 243,032 -- -- 243,032 Advances with
affiliates........................... (492,805)
13,563 479,242 -- Net proceeds from issuance of
common units.......... 286,699 -- -- 286,699
Redemption of Series B preference
units............. (50,000) -- -- (50,000)
Contributions from general
partner................... 2,843 -- -- 2,843
Distributions to
partners.......................... (105,923) --
(486) (106,409) --------- -------- --------- -----

---- Net cash provided by (used in) financing activities of continuing operations........................... (137,160) 13,563 478,756 355,159 Net cash provided by financing activities of discontinued operations............................ -- 49,960 -- 49,960 --------- -------- --------- --------- Net cash provided by (used in) financing activities.................................. (137,160) 63,523 478,756 405,119 --------- -------- --------- --------- Net (decrease) increase in cash and cash equivalents... $ (11,459) $ 1,155 $ 3,107 (7,197) ========= ======== ========= Cash and cash equivalents at beginning of year......... 20,281 --------- Cash and cash equivalents at end of year............... $ 13,084 =========

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 2000

	ISSUER	NON-GUARANTOR SUBSIDIARIES	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Cash flows from operating activities				
Net income (loss)	$ 413	$ (252)	$ 20,336	$ 20,497
Less income (loss) from discontinued operations	--	(252)	--	(252)
Income from continuing operations	413	--	20,336	20,749
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation, depletion and amortization	151	--	27,592	27,743
Distributed earnings of unconsolidated affiliates				
Earnings from unconsolidated affiliates	--	--	(22,931)	(22,931)
Distributions from unconsolidated affiliates	--	--	33,960	33,960
Litigation reserve	(2,250)	--	--	(2,250)
Other noncash items	2,964	--	(727)	2,237
Working capital changes, net of effects of acquisitions and non-cash transactions	(285)	800	(11,361)	(10,846)
Net cash provided by continuing operations	993	800	46,869	48,662
Net cash used in discontinued operations	--	(252)	--	(252)
Net cash provided by operating activities	993	548	46,869	48,410
Cash flows from investing activities				
Acquisitions and development of oil and natural gas properties	--	--	(172)	(172)
Additions to pipelines, platforms and facilities	(1,811)	--	(38)	(1,849)
Investments in unconsolidated affiliates	--	--	(8,979)	(8,979)
Cash paid for acquisitions, net of cash acquired	--	--	(26,476)	(26,476)
Other	(402)	--	21	(381)
Net cash used in investing activities of continuing operations	(2,213)	--	(35,644)	(37,857)
Net cash used in investing activities of discontinued operations	--	(88,356)	--	(88,356)
Net cash used in investing activities	(2,213)	(88,356)	(35,644)	(126,213)
Cash flows from financing activities				
Net proceeds from revolving credit facility	152,043	--	--	152,043
Repayments of revolving credit facility	(125,000)	--	--	(125,000)
Net proceeds from issuance of common units	100,634	--	--	100,634
Advances with affiliates	(34,765)	45,670	(10,905)	--
Redemption of publicly held preference units	(804)	--	--	(804)
Contribution from general partner	2,785	--	--	2,785
Distributions to partners	(78,529)	--	(801)	(79,330)
Net cash provided by (used in) financing activities of continuing operations	16,364	45,670	(11,706)	50,328
Net cash provided by financing activities of discontinued operations	--	43,554	--	

43,554 --------- -------- -------- --------- Net cash provided by (used in) financing activities................................ 16,364 89,224 (11,706) 93,882 --------- -------- -------- --------- Net increase in cash and cash equivalents............ $ 15,144 $ 1,416 $ (481) 16,079 ========= ======== ======== Cash and cash equivalents at beginning of year....... 4,202 --------- Cash and cash equivalents at end of year............. $ 20,281 =========

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 1999

	ISSUER	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)		
Cash flows from operating activities			
Net income	$ 190	$ 18,627	$ 18,817
Adjustments to reconcile net income to net cash (used in) provided by operating activities			
Depreciation, depletion and amortization	28	30,602	30,630
Gain on sales of assets	--	(10,103)	(10,103)
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	--	(32,814)	(32,814)
Distributions from unconsolidated affiliates	--	46,180	46,180
Litigation reserve	2,250	--	2,250
Other noncash items	2,072	(238)	1,834
Working capital changes, net of effects of acquisitions and non-cash transactions	(6,172)	138	(6,034)
Net cash provided by (used in) operating activities	(1,632)	52,392	50,760
Cash flows from investing activities			
Acquisitions and development of oil and natural gas properties	--	(3,218)	(3,218)
Additions to pipelines, platforms and facilities	(203)	(30,459)	(30,662)
Investments in unconsolidated affiliates	--	(59,348)	(59,348)
Cash paid for acquisitions, net of cash acquired	--	(20,351)	(20,351)
Proceeds from sale of assets	--	26,122	26,122
Distributions related to the formation of Deepwater Holdings	--	20,000	20,000
Other	(130)	452	322
Net cash used in investing activities	(333)	(66,802)	(67,135)
Cash flows from financing activities			
Net proceeds from revolving credit facility	141,126	--	141,126
Repayments of revolving credit facility	(226,850)	--	(226,850)
Advances with affiliates	(15,560)	15,560	--
Net proceeds from issuance of long-term debt	168,878	--	168,878
Contribution from general partner	603	--	603
Distributions to partners	(65,619)	(669)	(66,288)
Net cash provided by financing activities	2,578	14,891	17,469
Net increase in cash and cash equivalents	$ 613	$ 481	1,094
Cash and cash equivalents at beginning of year			3,108
Cash and cash equivalents at end of year			$ 4,202

16. SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION (UNAUDITED):

Oil and Natural Gas Reserves

The following table represents our net interest in estimated quantities of proved developed and proved undeveloped reserves of crude oil, condensate and natural gas and changes in such quantities at year end 2001, 2000 and 1999. Estimates of our reserves at December 31, 2001, 2000 and 1999, have been made by the independent engineering consulting firm, Netherland, Sewell & Associates, Inc. except for the Prince Field for 2001, which was prepared by El Paso Production Company, our affiliate and operator of the Prince Field. Net proved reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our policy is to recognize proved reserves only when economic producibility is supported by actual production. As a result, no proved reserves were booked with respect to any of our producing fields in the absence of actual production. Proved developed reserves are proved reserve volumes that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserve volumes that are expected to be recovered from new wells on undrilled acreage or from existing wells where a significant expenditure is required for recompletion. Reference Rules 4-10(a)(2)(i), (ii), (iii), (3) and (4) of Regulation S-X, for detailed definitions of proved reserves, which can be found at the SEC's website, http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

Estimates of reserve quantities are based on sound geological and engineering principles, but, by their very nature, are still estimates that are subject to substantial upward or downward revision as additional information regarding producing fields and technology becomes available.

	OIL/CONDENSATE MBBLS(1)	NATURAL GAS MMCF(1)
Proved reserves -- January 1, 1999	1,578	28,884
Revision of previous estimates	251	623
Extension, Discoveries, and other Additions	1	218
Production	(357)	(12,211)
Proved reserves -- December 31, 1999	1,473	17,514
Revision of previous estimates	23	1,171
Production	(295)	(7,185)
Proved reserves -- December 31, 2000	1,201	11,500
Revision of previous estimates(2)	1,852	5,913
Production(2)	(345)	(4,172)
Proved reserves -- December 31, 2001	2,708	13,241
Proved developed reserves December 31, 1999	1,473	15,061
December 31, 2000	1,201	9,126
December 31, 2001(2)	2,350	10,384

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(1) Includes our overriding royalty interest in proved reserves on Garden Banks Block 73 and the Prince Field.

(2) Includes our overriding royalty interest in proved reserves of 1,341 MBbls of oil and 1,659 MMcf of natural gas on our Prince Field, which began production in 2001. These reserves were not included in proved reserves prior to 2001 because, consistent with our policy, economic producibility had not been supported by actual production. Also, we had increases in estimated proved reserves relating to our producing properties, primarily at our West Delta 35 field. Actual production in the Prince Field for 2001 was 37 MBbls of oil and 32 MMcf of natural gas.

The following are estimates of our total proved developed and proved undeveloped reserves of oil and natural gas by producing property as of December 31, 2001.

	OIL (BARRELS)		NATURAL GAS (MCF)	
	PROVED DEVELOPED	PROVED UNDEVELOPED	PROVED DEVELOPED	PROVED UNDEVELOPED
	(IN THOUSANDS)			
Garden Banks Block 72	277	--	1,900	--
Garden Banks Block 117	1,065	--	1,556	--
Viosca Knoll Block 817	12	--	2,216	2,437
West Delta Block 35	13	--	3,473	--
Prince Field	983	358	1,239	420
Total	2,350	358	10,384	2,857

In general, estimates of economically recoverable oil and natural gas reserves and of the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the subject properties, the assumed effects of regulation by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs and future plugging and abandonment costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The meaningfulness of such estimates is highly dependent upon the assumptions upon which they are based.

Estimates with respect to proved undeveloped reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. A significant portion of our reserves is based upon volumetric calculations.

Future Net Cash Flows

The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is calculated and presented in accordance with SFAS No. 69, Disclosures About Oil and Gas Producing Activities. Accordingly, future cash inflows were determined by applying year-end oil and natural gas prices, as adjusted for fixed price contracts in effect, to our estimated share of future production from proved oil and natural gas reserves. The average prices utilized in the calculation of the standardized measure of discounted future net cash flows at December 31, 2001, were $16.75 per barrel of oil and $2.62 per Mcf of natural gas. Actual future prices and costs may be materially higher or lower. Future production and development costs were computed by applying year-end costs to future years. As we are not a taxable entity, no future income taxes were provided. A prescribed 10 percent discount factor was applied to the future net cash flows.

In our opinion, this standardized measure is not a representative measure of fair market value, and the standardized measure presented for our proved oil and natural gas reserves is not representative of the reserve value. The standardized measure is intended only to assist financial statement users in making comparisons between companies. In the table following, the amounts of future production costs have been restated to include platform access fees paid to our platform segment. See note 2 to the table for further discussion of the impact of such fees on our consolidated standardized measure of discounted future net cash flows.

	DECEMBER 31,		
	2001 (RESTATED)	2000 (RESTATED)	1999 (RESTATED)
	(IN THOUSANDS)		
Future cash inflows(1)	$ 80,603	$136,658	$ 69,719
Future production costs(2)	(19,252)	(28,933)	(35,730)
Future development costs	(10,530)	(11,531)	(10,681)
Future net cash flows	50,821	96,194	23,308
Annual discount at 10% rate	(11,761)	(18,488)	(5,479)
Standardized measure of discounted future net cash flows	$ 39,060	$ 77,706	$ 17,829

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(1) Our future cash inflows include estimated future receipts from our overriding royalty interest in our Prince Field and Garden Banks Block 73. Since these are overriding royalty interests, we do not participate in the production or development costs for these fields, but do include their proved reserves, production volumes and future cash inflows in our data.

(2) Our future production costs include platform access fees paid by our oil and natural gas production business to affiliated entities included in our platforms segment. Such platform access fees are eliminated in our consolidated financial statements. The future platform access fees paid to our platform segment were $4,960 for 2001, $13,080 for 2000 and $21,200 for 1999. On a consolidated basis, our standardized measure of discounted future net cash flows was $43,789 for 2001, $89,749 for 2000, and $36,518 for 1999.

Estimated future net cash flows for proved developed and proved undeveloped reserves as of December 31, 2001, are as follows:

	PROVED DEVELOPED (RESTATED)	PROVED UNDEVELOPED (RESTATED)	TOTAL
	(IN THOUSANDS)		
Undiscounted estimated future net cash flows from proved reserves before income taxes	$40,518	$10,303	$50,821
Present value of estimated future net cash flows from proved reserves before income taxes, discounted at 10%	$31,003	$ 8,057	$39,060

The following are the principal sources of change in the standardized measure:

	2001 (RESTATED)	2000 (RESTATED)	1999 (RESTATED)
	(IN THOUSANDS)		
Beginning of year	$ 77,706	$ 17,829	$ 26,672
Sales and transfers of oil and natural gas produced, net of production costs	(34,834)	(33,203)	(22,154)
Net changes in prices and production costs	(55,657)	119,457	29,901
Extensions, discoveries and improved recovery, less related costs	--	--	544
Oil and natural gas development costs incurred during the year	2,018	172	615
Changes in estimated future development costs	535	(511)	(1,098)
Revisions of previous quantity estimates	38,090	7,846	5,124
Accretion of discount	7,771	1,783	2,666
Changes in production rates, timing and other	3,431	(35,667)	(24,441)
End of year	$ 39,060	$ 77,706	$ 17,829

Development, Exploration, and Acquisition Expenditures

The following table details certain information regarding costs incurred in our development, exploration, and acquisition activities during the years ended December 31:

	2001	2000	1999
	(IN THOUSANDS)		
Development costs	$2,018	$172	$3,018
Capitalized interest	--	--	200
Total capital expenditures	$2,018	$172	$3,218

In each of the years presented, we elected not to incur any costs to develop our proved undeveloped reserves. However, we expect to incur approximately $2.6 million within the next three years to develop these reserves.

Capitalized Costs

Capitalized costs relating to our natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows as of December 31:

	2001	2000
	(IN THOUSANDS)	
Oil and natural gas properties		
Proved properties	$ 54,609	$ 53,572
Wells, equipment, and related facilities	104,766	102,748
	159,375	156,320
Less accumulated depreciation, depletion and amortization	108,307	101,161
	$ 51,068	$ 55,159

Results of operations

Results of operations from producing activities by fiscal year were as follows at December 31:

	2001	2000	1999
	(IN THOUSANDS)		
Natural gas sales	$18,248	$12,819	$24,829
Oil, condensate, and liquid sales	8,062	7,733	5,136
Total operating revenues	26,310	20,552	29,965
Production costs(1)	16,367	16,228	17,616
Depreciation, depletion and amortization	7,567	11,280	18,894
Results of operations from producing activities	$ 2,376	$(6,956)	$(6,545)

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(1) These production costs include platform access fees paid to affiliated entities included in our platforms segment. Such platform access fees, which were approximately $10 million in each of the years presented, are eliminated in our consolidated financial statements.

17. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION:

In previous years, we have reported earnings from unconsolidated affiliates as part of operating revenues. We have changed this presentation as of December 31, 2000, to include earnings from unconsolidated affiliates as other income. This change has been reflected for all periods presented.

	QUARTER ENDED (UNAUDITED)				
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR
	(IN THOUSANDS, EXCEPT PER UNIT DATA)				
2001					
Operating revenues	$54,502	$44,987	$41,268	$52,649	$193,406
Operating income	13,792	16,457	17,362	22,276	69,887
Income from continuing operations	13,716	11,572	11,558	17,206	54,052
Income (loss) from discontinued operations	(743)	272	479	1,089	1,097
Net income	12,973	11,844	12,037	18,295	55,149
Income (loss) allocation					
Series B preference unitholders	4,322	4,464	4,538	3,904	17,228
General Partner					
Continuing operations	4,702	5,901	5,809	8,237	24,650
Discontinued operations	(7)	3	10	11	16
	4,695	5,904	5,819	8,248	24,666
Limited Partners					
Continuing operations	4,692	1,207	1,211	5,066	12,175
Discontinued operations	(736)	269	948	1,077	1,559
	3,956	1,476	2,159	6,143	13,734
Basic and diluted earnings per unit					
Income from continuing operations	0.14	0.03	0.03	0.15	0.35
Discontinued operations	(0.02)	0.01	0.02	0.02	0.03
	0.12	0.04	0.05	0.17	0.38
Distributions declared per common unit	0.55	0.58	0.58	0.61	2.31
Weighted average numbers of units outstanding	32,471	34,070	32,471	36,209	34,376
2000					
Revenue	$18,950	$26,813	$29,642	$37,011	$112,415
Operating income	9,394	13,419	10,032	9,206	42,051
Income from continuing operations	1,939	8,367	4,936	5,507	20,749
Income (loss) from discontinued operations	--	--	(74)	(178)	(252)
Net income	1,939	8,367	4,862	5,329	20,497
Income (loss) allocation					
Net income allocated to Series B preference unitholders	--	--	1,417	4,251	5,668
General Partner					
Continuing operations	3,232	3,622	4,115	4,612	15,581
Discontinued operations	--	--	(1)	(2)	(3)
	3,232	3,622	4,114	4,610	15,578
Limited Partners					
Continuing operations	(1,293)	4,745	(596)	(3,356)	(500)
Discontinued operations	--	--	(73)	(176)	(249)
	(1,293)	4,745	(669)	(3,532)	(749)
Basic and diluted earnings (loss) per unit					
Income from continuing operations	(0.05)	0.18	(0.02)	(0.10)	(0.02)
Discontinued operations	--	0.00	(0.00)	(0.01)	(0.01)
	(0.05)	0.18	(0.02)	(0.11)	(0.03)

Distributions declared per common unit............. 0.525 0.5375 0.5375 0.550 2.150 Distributions declared per preference unit......... 0.275 0.275 0.275 -- 0.825 Weighted average numbers of units outstanding...... 27,029 27,029 31,229 31,550 29,077

18. SUBSEQUENT EVENT -- PRINCE TLP DISPOSITION

In connection with our acquisition of midstream assets from El Paso Corporation, we committed in February 2002 to dispose of our Prince 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 reported as discontinued operations and have been excluded from continuing operations for all periods in our statements of income and cash flows. Accordingly, the segment results in Note 14 do not reflect 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 the related royalty interest was included in the oil and natural gas sales segment (subsequently renamed the "Other segment"). Included in income from discontinued operations for the year ended December 31, 2001, was operating revenues of $8.8 million. We did not recognize any revenues related to the Prince assets during the years ended December 31, 2000 and 1999.

The assets and liabilities related to the Prince assets disposition consisted of the following:

	DECEMBER 31,	
	2001	2000
Property, plant and equipment	$189,432	$121,492
Accumulated depreciation	(3,872)	--
Assets held for sale, net	185,560	121,492
Unamortized debt issue costs	1,091	1,445
Limited recourse term loan	(95,000)	(45,000)
Accrued interest on term loan	(703)	(292)
Net assets related to the Prince assets disposition	$ 90,948	$ 77,645

In April 2002, we sold the Prince assets for $190 million and recognized a loss on the sale of less than $0.1 million which will be recorded in the second quarter of 2002. In conjunction with this transaction, we repaid the related outstanding $95 million principal balance under our limited recourse term loan.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Unitholders of El Paso Energy Partners, L.P.
and the Board of Directors and Stockholder of
El Paso Energy Partners Company, as General Partner:

In our opinion, the consolidated financial statements listed in the index appearing under Item 14(a)1. on page 111 present fairly, in all material respects, the financial position of El Paso Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 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 disclosed in Note 1 to the consolidated financial statements, the Partnership changed its method for allocating net income to its partners in 1999.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2002, except for Note 18, as to
which the date is June 28, 2002

SIGNATURES

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

EL PASO ENERGY PARTNERS, L.P.

By: EL PASO ENERGY PARTNERS COMPANY,
its General Partner

By: /s/ D. MARK LELAND

D. Mark Leland
Senior Vice President and Controller
(Principal Accounting Officer)

Date: January 2, 2003