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

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2002

OR

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

For the transition period from __________ to__________

COMMISSION FILE NO. 1-11680

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.)
4 GREENWAY PLAZA HOUSTON, TEXAS (Address of Principal Executive Offices)	77046 (Zip Code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE: (832) 676-6152

INTERNET WEBSITE: WWW.ELPASOPARTNERS.COM

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common units representing limited partner interests	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: NONE.

INDICATE BY CHECK MARK WHETHER THE REGISTRANT (1) HAS FILED ALL REPORTS REQUIRED TO BE FILED BY SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 DURING THE PRECEDING 12 MONTHS (OR FOR SUCH SHORTER PERIOD THAT THE

REGISTRANT WAS REQUIRED TO FILE SUCH REPORTS), AND (2) HAS BEEN SUBJECT TO SUCH FILING REQUIREMENTS FOR THE PAST 90 DAYS.   YES [X]   NO [ ]

INDICATE BY CHECK MARK IF DISCLOSURE OF DELINQUENT FILERS PURSUANT TO ITEM 405 OF REGULATION S-K IS NOT CONTAINED HEREIN, AND WILL NOT BE CONTAINED, TO THE BEST OF REGISTRANT'S KNOWLEDGE, IN DEFINITIVE PROXY OR INFORMATION STATEMENTS INCORPORATED BY REFERENCE IN PART III OF THIS FORM 10-K OR ANY AMENDMENT TO THIS FORM 10-K.   [ ]

INDICATE BY CHECK MARK WHETHER THE REGISTRANT IS AN ACCELERATED FILER (AS DEFINED IN EXCHANGE ACT RULE 12B-2).   YES [X]   NO [ ]

THE REGISTRANT HAD 44,030,314 COMMON UNITS OUTSTANDING AS OF MARCH 24, 2003. THE AGGREGATE MARKET VALUE ON MARCH 24, 2003 AND JUNE 28, 2002 OF THE REGISTRANT'S COMMON UNITS HELD BY NON-AFFILIATES WAS APPROXIMATELY $1,369 MILLION AND $1,403 MILLION.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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EL PASO ENERGY PARTNERS, L.P.

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PART I

ITEM 1. BUSINESS

GENERAL

Formed in 1993, we are one of the largest publicly-traded master limited partnerships (MLP) in terms of market capitalization. Since El Paso Corporation's initial acquisition of an interest in us in 1998, we have diversified our asset base, stabilized our cash flow and decreased our financial leverage as a percentage of total capital. We have accomplished this through a series of acquisitions and development projects as well as four public offerings of our common units. We manage a balanced, diversified portfolio of interests and assets relating to the midstream energy sector, which involves gathering, transporting, separating, handling, processing, fractionating and storing natural gas, oil and natural gas liquids (NGL). This portfolio, which we consider to be balanced due to its diversity of geographic locations, business segments, customers and product lines, includes:

- offshore oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure in the Gulf of Mexico, primarily offshore Louisiana and Texas;

- onshore natural gas pipelines and processing facilities in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas;

- onshore NGL pipelines and fractionation facilities in Texas; and

- onshore natural gas and NGL storage facilities in Mississippi, Louisiana and Texas.

We are one of the largest natural gas gatherers, based on miles of pipeline, in the prolific natural gas supply regions offshore in the Gulf of Mexico and onshore in Texas and the San Juan Basin, which envelops a significant portion of the four contiguous corners of Arizona, Colorado, New Mexico and Utah. These regions, especially the deeper water regions of the Gulf of Mexico, one of the United States' fastest growing natural gas producing regions, offer us significant infrastructure growth potential through the acquisition and construction of pipelines, platforms, processing and storage facilities and other infrastructure. In 2002, the Gulf of Mexico accounted for approximately 25 percent of all natural gas production in the United States and the supply regions accessed by our pipelines in Texas and the San Juan Basin accounted for approximately 33 percent.

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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
Bbl	= barrel
BBtu	= billion British thermal units
Bcf	= billion cubic feet
Dth	= dekatherm
MBbls	= thousand barrels
Mcf	= thousand cubic feet
MDth	= thousand dekatherms
MMBbls	= million barrels
MMBtu	= million British thermal units
MMcf	= million cubic feet
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.

Our objective is to operate as a growth-oriented MLP with a focus on increasing cash flow, earnings and return to our unitholders by becoming one of the industry's leading providers of midstream energy services. Our strategy entails striving to continually enhance the quality of our cash flow by:

- maintaining a balanced and diversified portfolio of midstream energy interests and assets;

- maintaining a sound capital structure;

- sharing capital costs and risks through joint ventures/strategic alliances; and

- emphasizing fee-based operations and services for which the fees are not traditionally linked to commodity prices (like gathering and transportation) and managing commodity risks by using contractual arrangements (like fixed-fee contracts and hedging and tolling arrangements) and de-emphasizing our commodity-based activities (including exiting the oil and natural gas production business by not acquiring additional properties).

We intend to execute our business strategy by:

- constructing and acquiring onshore pipelines, gathering systems, processing and fractionation facilities and other midstream assets to provide a broad range of more stable, fee-based services to producers, marketers and users of energy products;

- expanding our existing offshore asset base, supported by the dedication of new discoveries and long-term commitments, to capitalize on the accelerated growth of oil and natural gas supplies from the deeper water regions of the Gulf of Mexico;

- operating at low cost by achieving economies of scale in select regions through reinvesting in and expanding our organic growth opportunities, as well as by acquiring new assets;

- sharing capital costs and risks through joint ventures/strategic alliances, principally with partners with substantial financial resources and strategic interests, assets and operations in the Gulf of Mexico, especially in the deeper water, Flextrend and subsalt regions; and

- continuing to strengthen our solid balance sheet by seeking to finance and/or refinance our growth, on average, with 50 percent equity so as to provide the financial flexibility to fund future opportunities.

In 2002, our cash outlay for investments of midstream energy infrastructure assets totaled $1.7 billion. Assets acquired from El Paso Corporation and third parties totaled $1.5 billion and $19 million, and funds expended for the construction of assets totaled $228 million.

Our partners in the Gulf of Mexico include integrated and large independent energy companies with substantial offshore interests, operations and assets, such as Shell Oil Products, U.S. and Marathon Pipeline Company. We have entered into a letter of intent with Valero Energy Corporation, one of the top refining and marketing companies in the United States, to be our partner in our Cameron Highway Oil Pipeline project.

RECENT EVENTS

San Juan Acquisition

In November 2002, we acquired the San Juan assets from subsidiaries of El Paso Corporation for $782 million, $766 million after adjustments for capital expenditures and working capital. The acquired assets include a natural gas gathering system located in the San Juan Basin of New Mexico, including El Paso Corporation's remaining interest in the Chaco cryogenic natural gas processing plant; NGL transportation and fractionation assets located in Texas; and an oil and natural gas gathering system located in the deeper water regions of the Gulf of Mexico. The following is a description of the San Juan assets.

- The assets located in the San Juan Basin include:

  - approximately 5,300 miles of natural gas gathering pipelines, known as the San Juan gathering system, with capacity of over 1.1 Bcf/d that is connected to approximately 9,500 wells producing natural gas from the San Juan Basin located in northwest New Mexico and southwest Colorado;

  - approximately 250,000 horsepower of compression;

  - the 58 MMcf/d Rattlesnake CO_2 treating facility;

  - a 50 percent interest in Coyote Gas Treating, LLC, the owner of a 250 MMcf/d treating facility; and

  - the remaining interests in the Chaco cryogenic natural gas processing plant that we did not already own and the price risk management positions related to this facility's operations.

- The offshore pipeline assets include:

  - The Typhoon gas pipeline, a 35-mile, 20-inch natural gas pipeline originating on the Chevron/BHP "Typhoon" platform in the Green Canyon area of the Gulf of Mexico extending to the ANR Patterson System in Eugene Island Block 371; and

  - The Typhoon oil pipeline, a 16-mile, 12-inch oil pipeline originating on the Chevron/BHP "Typhoon" platform and extending to a platform in Green Canyon Block 19 with onshore access through various oil pipelines.

- The Texas NGL assets include:

  - a 163-mile, 4 to 6-inch propane pipeline extending from Corpus Christi to McAllen and the Hidalgo truck terminal facilities;

  - the Markham butane shuttle, a 124-mile, 8-inch pipeline with capacity of approximately 20 MBbls/d running between Corpus Christi and a leased storage facility at Markham with capacity of approximately 3.8 MMBbls;

  - a 49-mile, 6-inch pipeline with capacity of approximately 15 MBbls/d extending from the Almeda fractionator to Texas City and the Texas City terminal;

  - the Almeda fractionator, a 24 MBbls/d fractionator consisting of two trains, with both trains currently out of service, and related leased storage facilities of approximately 14.3 MMBbls; and

  - a 201-mile, 8 to 10-inch pipeline with capacity of approximately 35 MBbls/d extending from Corpus Christi to the Almeda fractionator in Pasadena. This pipeline is currently out of service.

We are required to make approximately $49 million of capital expenditures to place the 201-mile 8 to 10-inch pipeline back in service and make repairs and upgrades on the Markham butane shuttle and the Almeda fractionator.

We financed our acquisition of the San Juan assets through long-term debt and equity as outlined below (in millions):

Series C units	$350
Senior secured acquisition term loan	238
Senior subordinated notes	194
Initial purchase price	782
Less working capital and capital expenditure adjustments	16
Net purchase price	$766

We issued 10,937,500 of our Series C units to El Paso Corporation for a value of $350 million. See "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources" for further discussion of the acquisition financing, including a description of the Series C units. The remaining balance of the purchase price was paid in cash. We funded the cash portion of the purchase price with net proceeds of $238 million from a senior secured acquisition term loan and $194 million from our issuance of senior subordinated notes. We repaid the senior secured acquisition term loan in March 2003 with proceeds from our issuance of $300 million of 8 1/2% Senior Subordinated Notes.

As part of this transaction, El Paso Corporation is required, subject to specified conditions, to repurchase the Chaco processing plant from us for $77 million in October 2021, and at that time, we will have the right to lease the plant from El Paso Corporation for a period of ten years with the option to renew the lease annually thereafter.

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

EPN Holding Acquisition

In April 2002, EPN Holding Company, L.P., our wholly-owned subsidiary, acquired from subsidiaries of El Paso Corporation, midstream assets located in Texas and New Mexico. The acquired assets, which we refer to as the EPN Holding assets, include:

- the EPGT Texas intrastate pipeline system;

- the Waha natural gas gathering system and treating plant located in the Permian Basin region of Texas;

- the Carlsbad natural gas gathering system located in the Permian Basin region of New Mexico;

- an approximate 42.3 percent non-operating interest in the Indian Basin natural gas processing and treating facility located in southeastern New Mexico and price risk management activities associated with the plant;

- a 50 percent undivided interest in the Channel natural gas pipeline system located along the Gulf coast of Texas;

- the TPC Offshore natural gas pipeline system located off the Gulf coast of Texas; and

- a leased interest in the Wilson natural gas storage facility located in Wharton County, Texas.

The $750 million sales price was adjusted for the assumption of $15 million of working capital related to natural gas imbalances. The net consideration of $735 million for the EPN Holding assets was comprised of the following (in millions):

Cash	$420
Assumed short term indebtedness payable to El Paso Corporation (none of which is outstanding as of December 31, 2002)	119
Common units	6
Sale of our Prince tension leg platform (TLP) and our nine percent Prince overriding royalty interest	190
	$735

To finance substantially all of the cash consideration related to this acquisition, EPN Holding entered into a $535 million term loan facility with a syndicate of commercial banks, of which $375 million has been repaid and the remaining amount was restructured in October 2002. This term loan facility and the restructuring are described in more detail in "Management's Discussion and Analysis of Financial Condition

and Results of Operations -- Liquidity and Capital Resources" and Item 8, Financial Statements and Supplementary Data, Note 6.

SEGMENTS

In light of our expectation of acquiring additional natural gas pipeline and processing assets, effective January 1, 2002, we revised and renamed our business segments to reflect the change in composition of our operations for all periods presented, as discussed below. 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.

These segments are strategic business units that provide a variety of energy related services. For information relating to revenues from external customers, operating income and total assets of each segment, see Item 8, Financial Statements and Supplementary Data, Note 14. Each of these segments is discussed more fully below.

NATURAL GAS PIPELINES AND PLANTS

Natural Gas Pipelines Systems

We own interests in natural gas pipeline systems extending over 15,700 miles, with a combined maximum design capacity (net to our interest) of over 10.3 Bcf/d of natural gas. We own or have interests in gathering systems onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas including the San Juan gathering system and the Texas Intrastate system. In addition to our onshore natural gas pipeline systems, our offshore natural gas pipeline systems are strategically located to serve production activities in some of the most active drilling and development regions in the Gulf of Mexico, including select locations offshore of Texas, Louisiana and Mississippi, and to provide relatively low cost access to long-line transmission pipelines that access multiple markets in the eastern half of the United States.

The following table and discussions describe our natural gas pipelines, all of which (other than portions of the Texas Intrastate system) we wholly own and operate.

	TEXAS INTRASTATE(1)(2)	SAN JUAN(3)	PERMIAN BASIN(1)	VIOSCA KNOLL	HIOS(2)(4)	EAST BREAKS(4)	TYPHOON(3)	EPIA(2)
In-service date................	Various	Various	Various	1994	1977	2000	2001	1972
Approximate capacity(5)........	4,975	1,100	470	1,000	1,800	400	400	200
Aggregate miles of pipeline....	8,222	5,300	1,343	125	204	85	35	450
Average throughput for the years ended: (6)								
December 31, 2002..............	3,362	1,244	335	565	740	203	62	175
December 31, 2001..............	3,478	1,196	344	551	979	245	51	171
December 31, 2000..............	3,985	1,237	317	612	870	112	--	120

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(1) The average throughput reflects 100 percent of the throughput. We acquired the Texas Intrastate system and the Permian Basin system together with the other EPN Holding assets in April 2002 from subsidiaries of El Paso Corporation.

(2) The Texas Intrastate system is comprised of the EPGT Texas intrastate, the TPC Offshore and the Channel pipeline systems. The Railroad Commission of Texas regulates the rates of the EPGT Texas and Channel systems. The Federal Energy Regulatory Commission (FERC) regulates the Section 311 rates of the EPGT Texas system, the Channel system and EPIA. HIOS is also regulated by the FERC as an interstate pipeline under the Natural Gas Act.

(3) The average throughput reflects 100 percent of the throughput. We acquired the San Juan gathering system and the Typhoon natural gas pipeline together with the other San Juan assets in November 2002 from a subsidiary of El Paso Corporation. The Typhoon natural gas pipeline was placed in service in August 2001.

(4) The average throughput reflects 100 percent of the throughput. Prior to October 2001, we indirectly owned a 50 percent interest in HIOS and East Breaks. We acquired the remaining 50 percent interest in October 2001 from subsidiaries of El Paso Corporation.

(5) All capacity measures are on a MMcf/d basis, and net to our interest with respect to Texas Intrastate.

(6) All average throughput measures are on a MDth/d basis. For the pipelines described above, one MDth is approximately equivalent to one MMcf.

Texas Intrastate. The Texas Intrastate system, which we acquired in April 2002, consists of the following natural gas pipelines:

- EPGT Texas Intrastate. The EPGT Texas Intrastate natural gas gathering system is one of the largest intrastate pipeline systems based on miles of pipe in the United States. It is also the only intrastate pipeline in Texas that offers transportation and storage services fully unbundled from marketing services. The system consists of approximately 7,292 miles of main lines, laterals and gathering lines with an operating capacity (net to our interest) of 3,725 MMcf/d. The EPGT Texas intrastate system includes some small pipelines in which we own undivided interests.

- TPC Offshore. TPC Offshore is a natural gas gathering system located in the coastal waters of south Texas, consisting of 197 miles of predominantly 8-inch to 20-inch pipelines that gather "rich" natural gas. The TPC Offshore system includes some smaller pipelines in which we own undivided interests.

- Channel pipeline system. The Channel pipeline system is an intrastate natural gas transmission system located along the Gulf coast of Texas, consisting of 733 miles of predominantly 30-inch pipelines. We own a 50 percent undivided interest in the Channel pipeline system.

San Juan Gathering System. The San Juan natural gas gathering system, which we acquired in November 2002, is located in the San Juan Basin. The system consists of approximately 5,300 miles of main lines, laterals and gathering lines with capacity of over 1.1 Bcf/d. A significant portion of the rights-of-way underlying the San Juan gathering system on Native American lands expire in 2005. We believe we will be able to renew these rights-of-way on terms and conditions that will not materially adversely affect us.

Permian Basin. The Permian Basin system, which we acquired in April 2002, consists of the following natural gas pipelines:

- Waha Natural Gas Gathering System. The Waha natural gas gathering system is a natural gas gathering system located in the Permian Basin region of Texas, and consists of 501 miles of predominantly 8 to 24-inch pipelines.

- Carlsbad Natural Gas Gathering System. The Carlsbad gathering system is a natural gas gathering system located in the Permian Basin region of New Mexico and consists of approximately 842 miles of predominantly 4-inch to 12-inch pipelines.

Viosca Knoll System. The Viosca Knoll system is an offshore natural gas gathering system that connects the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico with the facilities of a number of major interstate pipelines, including pipelines owned by Tennessee Gas Pipeline Company, Columbia Gulf Transmission Company, Southern Natural Gas Company, Transcontinental Gas Pipeline Company (Transco) and Destin Pipeline Company.

High Island Offshore System. HIOS, which became a wholly-owned asset in October 2001 through our acquisition of the remaining 50 percent interest from subsidiaries of El Paso Corporation, is an offshore natural gas transmission system that transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island, and East Breaks areas of the Gulf of Mexico to numerous downstream pipelines, including the ANR and Tennessee Gas pipelines owned by El Paso Corporation.

East Breaks System. The East Breaks natural gas gathering system, which became a wholly-owned asset in October 2001 through our acquisition of the remaining 50 percent interest that we did not already own, connects HIOS to the Hoover-Diana project developed by subsidiaries of ExxonMobil and BP in the Alaminos Canyon and East Breaks areas of the Gulf of Mexico. East Breaks has the ability to expand its throughput capacity further, which would provide HIOS with the ability to compete for the right to gather and transport the substantial reserves associated with properties being, and expected to be, developed in these deepwater frontier regions.

Typhoon Natural Gas Pipeline. The Typhoon pipeline, which we acquired in November 2002, is an offshore gas pipeline that connects the Typhoon field in the Green Canyon area of the Gulf of Mexico with El Paso Corporation's ANR Patterson Offshore pipeline system. We intend to integrate this pipeline into the Marco Polo natural gas pipeline.

El Paso Intrastate-Alabama System. EPIA, which we acquired in March 2000, is a natural gas pipeline system that serves the coal bed methane producing regions of Alabama. EPIA provides marketing services through the purchase of natural gas from regional producers and others, and sale of natural gas to local distribution companies and others.

EPIA gathering system provides marketing services and, accordingly, purchases and resells the natural gas it gathers. Several of our other gathering systems, while not providing marketing services, have some exposure to risks related to commodity prices. For example, over 95 percent of the volumes handled by the San Juan gathering system are handled under fee-based arrangements, 80 percent of which are calculated as a percentage of a regional price index for natural gas. If we do not use hedges or similar arrangements, the financial results for these assets could be affected by changes in, or the volatility of, commodity prices. Additionally, the San Juan gathering system provides aggregating and bundling services for smaller producers, whereby we purchase natural gas at the wellhead and resell natural gas in the open market at points along our pipeline. These services account for less than five percent of the volumes on that system.

Natural Gas Processing and Treating Facilities

We own interests in five processing and treating plants in Louisiana, New Mexico, Texas and Colorado with a combined maximum capacity of over 1.5 Bcf/d of natural gas and 50 MBbls/d of NGL. The following table and discussions describe our natural gas processing and treating facilities.

	PROCESSING		TREATING		
	CHACO	INDIAN BASIN(2)	COYOTE(3)	WAHA	RATTLESNAKE
Ownership interest......	100%	42.3%	50%	100%	100%
Location of facility....	New Mexico	New Mexico	Colorado	Texas	New Mexico
In-service date.........	1996	1964	1996	1966	1999
Date acquired...........	2001	2002	2002	2002	2002
Approximate capacity(1)...........	650	300	250	285	58
Average utilization rates for the year ended:					
December 31, 2002.....	90%	93%	N/A(4)	54%	61%(5)
December 31, 2001.....	89%	93%	79%	61%	95%
December 31, 2000.....	91%	82%	69%	61%	94%

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(1) All capacity measures are on a MMcf/d basis. Indian Basin and Coyote are reflected at 100 percent capacity.

(2) We own a non-operating interest in the Indian Basin plant. The average utilization rates were calculated with 100 percent of volumes and capacity.

(3) As part of the San Juan assets acquisition in November 2002, we acquired our interest in Coyote Gas Treating, LLC. The average utilization rates were calculated with 100 percent of volumes and capacity.

(4) Effective January 2002, Coyote Gas Treating, LLC entered into a five year operating lease agreement. Under the terms of the lease, Coyote Gas Treating, LLC receives fixed monthly lease payments of $635 thousand. We no longer receive volume data from the operator because our proportionate share of the revenues is now based on the fixed lease payments.

(5) The decrease in Rattlesnake's utilization rate is the result of an expansion during 2002 which increased the capacity of the plant to 58 MMcf/d from 25 MMcf/d.

The Chaco cryogenic natural gas processing plant is the fifth largest natural gas processing plant in the United States measured by liquids produced. The Chaco plant is a state-of-the-art cryogenic plant located in the San Juan Basin in New Mexico that uses high pressures and extremely low temperatures to remove water, impurities and excess hydrocarbon liquids from the raw natural gas stream and to recover ethane, propane and the heavier hydrocarbons. It is capable of processing up to 650 MMcf/d of natural gas and handling up to 50 MBbls/d of NGL. In October 2001, we acquired substantially all of the interests in the Chaco plant from affiliates of El Paso Corporation. We acquired all remaining interests in the Chaco plant in November 2002. El Paso Corporation is required, subject to specific conditions, to repurchase the Chaco plant from us in 2021 for $77 million, and we will have the option to lease the plant back from El Paso Corporation for 10 additional years with the option to renew the lease annually thereafter.

Construction Projects

Medusa Project. We are constructing the $28 million, 37-mile Medusa natural gas pipeline extension of our Viosca Knoll gathering system with capacity to handle 160 MMcf/d of natural gas, which is expected to be in service in the third quarter of 2003. The pipeline is designed and located to gather production from Murphy Exploration and Production Company's Medusa development in the Gulf of Mexico. Murphy has dedicated 34,560 acres of property to this pipeline for the life of the reserves, which means that all natural gas produced from this acreage will flow through this pipeline. As of December 31, 2002, we have spent approximately $17.2 million related to this pipeline extension, which is currently under construction. We expect to receive contributions in aid of construction from Tennessee Gas Pipeline Company, a subsidiary of El Paso Corporation, of $2 million for benefits they expect to receive from our construction of the pipeline extension. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

Phoenix (formerly known as Red Hawk). We will build and operate a new $63 million pipeline, now known as the Phoenix gathering system, to gather natural gas production from the Red Hawk Field located in the Garden Banks area of the Gulf of Mexico. We have entered into related agreements with Kerr-McGee Oil and Gas Corporation, a wholly owned subsidiary of Kerr-McGee Corporation, and Ocean Energy, Inc., which each hold a 50-percent working interest in the Red Hawk Field. Kerr-McGee Oil and Gas Corporation and Ocean Energy, Inc. have dedicated multiple blocks at and in the proximity of the Red Hawk Field to this pipeline for the life of the reserves, subject to certain release provisions. The 76-mile pipeline, capable of transporting up to approximately 450 MMcf/d of natural gas, will originate in 5,300 feet of water at the Red Hawk Field and connect to the ANR Pipeline system at Vermillion Block 397. We plan to place the new pipeline in service during the second quarter of 2004. As of December 31, 2002, we have spent approximately $0.1 million related to this pipeline, which is in the development stage. We expect to receive contributions in aid of construction from ANR Pipeline Company, a subsidiary of El Paso Corporation, of $6.1 million for benefits they expect to receive from our construction of this pipeline. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

Marco Polo Project. We will construct and own a 75-mile, 18-inch and 20-inch natural gas pipeline to support the Marco Polo TLP. The natural gas pipeline, with a maximum capacity of 400 MMcf/d, will gather natural gas from the Marco Polo platform in Green Canyon Block 608 and transport it to the Typhoon natural gas pipeline in Green Canyon Block 237. We intend to integrate the Marco Polo natural gas pipeline and Typhoon natural gas pipeline. This pipeline is expected to be completed and placed in service in the first quarter of 2004, and is expected to cost $68 million to construct. As of December 31, 2002, we have spent approximately $1.3 million on this pipeline, which is in the development stage. Additionally, we expect to receive contributions in aid of construction from ANR Pipeline Company and El Paso Field Services, subsidiaries of El Paso Corporation, totaling $17.5 million for benefits they anticipate receiving from our construction of the natural gas pipeline. As of December 2002, we received approximately $2 million from ANR as contributions in aid of construction of this pipeline. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

Markets and Competition

Each of our natural gas pipeline systems is located at or near natural gas production areas that are served by other pipelines, and face competition from both regulated and unregulated systems. Some of these competitors are not subject to the same level of rate and service regulation as we are.

Our gathering and transportation agreements have varying terms. Our offshore gathering and transportation arrangements tend to have longer terms, often involving life-of-reserve commitments with both firm and interruptible components, and our onshore gathering and transportation arrangements generally have terms from one month to several years. With respect to the San Juan gathering system, approximately 70 percent of the volume in 2002 is attributable to three customers, Burlington Resources, Conoco and BP. These contracts expire in 2008, 2006 and 2006. The following table indicates the percentage revenue generated by each contract in relation to the indicated denominator for the year ended December 31, 2002:

BASE REVENUE	BURLINGTON RESOURCES	CONOCO	BP	TOTAL
San Juan gathering revenue(1)...........	30.6%	20.9%	14.5%	66.0%
Total revenue of natural gas pipelines and plants segment(1)................	8.6%	5.8%	4.0%	18.4%

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(1) We have assumed twelve months of San Juan revenues in our calculation of the percentage revenue generated by each customer in order to more accurately reflect annual results. The revenue reflected in our statement of income only includes San Juan as of the acquisition date.

For a discussion of our significant customers, see Item 8, Financial Statements and Supplementary Data, Note 13.

Furthermore, the rates we charge for our services are dependent on whether the relevant pipeline system is regulated or unregulated, the quality of the service required by the customer, and the amount and term of the reserve commitment by the customer. Gathering arrangements are fee-based and, except for the EPIA and San Juan gathering system fees, generally do not have exposure to risks associated with changes in commodity prices. However, our financial results from some of our onshore pipelines, including the EPIA, Permian Basin and San Juan gathering systems, can be affected by a reduction in, or volatility of, commodity prices. The EPIA gathering system provides marketing services and, accordingly, purchases and resells the natural gas it gathers. Several of our other gathering systems, while not providing marketing services, have some exposure to risks related to commodity prices. For example, over 95 percent of the volumes handled by the San Juan gathering system are fee-based arrangements, 80 percent of which are calculated as a percentage of a regional price index for natural gas. In connection with our November 2002 San Juan assets acquisition, we terminated our tolling arrangement covering the Chaco plant with a subsidiary of El Paso Corporation, effectively replacing the fixed fee revenue previously received by the Chaco plant with actual revenues derived from sales of natural gas on the open market, which may produce greater volatility in our Chaco plant revenues. Our revenues would have approximated $0.234/Dth, $0.263/Dth and $0.206/Dth as compared to $0.134/Dth had we operated the Chaco plant during the years ended December 31, 2002, 2001 and 2000 under our current arrangement. In addition, the San Juan gathering system provides aggregating and bundling services, in which we purchase gas at the wellhead and resell gas in the open market at points on our system, for some smaller producers, which account for less than five percent of the volumes on that system. We use hedges from time to time to mitigate exposure to risks related to commodity prices.

Regulatory Environment

Our natural gas pipeline systems are subject to the Natural Gas Pipeline Safety Act of 1968, which establishes pipeline and liquified natural gas plant safety requirements. All of our offshore pipeline systems are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico. Each of the pipeline systems has continuous inspection and compliance programs designed to keep our facilities in compliance with pipeline safety and pollution control requirements. We believe that our pipeline systems are in material compliance with the applicable requirements of these regulations.

Our Texas intrastate natural gas assets, some of which are classified as "gas utilities," are regulated by the Railroad Commission of Texas.

Our HIOS system is also subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a separate FERC approved tariff that governs its operations, terms and conditions of service and rates. The natural gas pipeline industry has historically been heavily regulated by federal and state governments, and we cannot predict what further actions FERC, state regulators, or federal and state legislators may take in the future. We timely filed a required rate case for our HIOS system on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee, and changes to depreciation rates and negative salvage amortization. HIOS' filing reflects a zero rate base; therefore, a management fee in place of a return on rate base has been requested. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. The FERC has scheduled a hearing on this matter commencing November 17, 2003.

The FERC has issued two Notices of Proposed Rulemaking (NOPR) that may affect our HIOS operations. See Item 8, Financial Statements and Supplementary Data, Note 10 -- Commitments and Contingencies -- Rates and Regulatory Matters.

EPGT's FERC Section 311 service rates are subject to FERC rate jurisdiction. In December 1999, EPGT Texas filed a petition with the FERC for approval of its maximum rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to EPGT Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering services. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. EPGT Texas has established a reserve for refunds. In July 2002, EPGT Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. EPGT Texas' request for rehearing has been granted for further consideration and is pending before the FERC.

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

In December 2002, EPGT Texas requested FERC approval of market-based rates for interstate gas storage services performed at its Wilson storage facility. The filing was in compliance with a requirement to rejustify its existing rates or request new rates by December 20, 2002. Falcon has also intervened in this filing. This matter is pending before the FERC.

Environmental

Our natural gas pipelines and plants are subject to various safety and environmental statutes, including: the Natural Gas Act, the Natural Gas Policy Act, the Outer Continental Shelf Act, the Hazardous Materials Transportation Act, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and similar state statutes. We expect to make capital expenditures for environmental matters of approximately $10 million in the aggregate for the years 2003 through 2007, primarily to comply with clean air regulations. For a discussion of environmental regulations, see Environmental-Specific Regulations.

Maintenance

Each of our pipeline systems requires regular maintenance. The interior of the pipelines is maintained through the regular cleaning of the line of liquids that collect in the pipeline. Corrosion inhibitors are also injected into all of the systems through the flow stream on a continuous basis. To prevent external corrosion of the pipe, anodes are fastened to the pipeline itself at prescribed intervals, providing protection from sea water. Our HIOS and Viosca Knoll natural gas pipeline systems include platforms that are manned on a continuous basis. The personnel on board these platforms are responsible for site maintenance, operations of the platform facilities, measurement of the oil or natural gas stream at the source of production and corrosion control. Furthermore, the integrity of our onshore pipelines is subject to on-going integrity assessment and evaluation pursuant to the Pipeline Integrity Management Plan filed with the Railroad Commission of Texas and revised from time to time. The Pipeline Integrity Management Plan identifies all pipelines covered by the plan, establishes a priority ranking for performing the integrity assessment of pipeline segments of each pipeline system and makes an assessment of pipeline integrity using methods such as in-line inspection, pressure testing, direct assessment or other technology or assessment methodology. This integrity management program is reassessed and refined as necessary on at least an annual basis by qualified personnel.

Our processing and treating facilities are manned on a continuous basis by personnel who are responsible for maintenance and operations. The maintenance of the facilities is an ongoing process, which is performed based on hours of operation, oil analysis and vibration monitoring. Shutdown of our processing and treating facilities is not required for regular maintenance activity. Coyote and Indian Basin are operated and maintained by third parties that own interests in those systems.

OIL AND NGL LOGISTICS

NGL Transportation and Fractionation Facilities

EPN Texas. In February 2001, we acquired EPN Texas from subsidiaries of El Paso Corporation. EPN Texas includes more than 500 miles of intrastate NGL gathering and transportation pipelines and three fractionation plants located in south Texas. The intrastate NGL pipeline system is comprised of 379 miles of pipeline used to gather and transport unfractionated NGL from various processing plants to the Shoup Plant, located in Corpus Christi, the largest of EPN Texas' three fractionators. The system also includes 161 miles of pipelines that deliver fractionated products such as ethane, propane, butane and natural gasoline to refineries and petrochemical plants along the Texas Gulf Coast and to common carrier NGL pipelines. The three fractionation facilities have a combined capacity of approximately 96 MBbls/d. Utilization rates in the fractionation industry can fluctuate dramatically from month to month, depending on the needs of producers. However, the average utilization rate for EPN Texas for years ended December 31, 2002, 2001 and 2000 was 74 percent, 73 percent and 89 percent.

Additional Texas NGL Facilities. As part of the November 2002 San Juan assets acquisition, we acquired from subsidiaries of El Paso Corporation additional NGL assets located in Texas. These assets include over 500 miles of NGL pipelines that transport propane and butane to refineries and petrochemical users from Corpus Christi to Houston and within the Houston-Texas City area. These assets also provide access to the Mont Belvieu NGL markets. Portions of these NGL assets are shut-in pending refurbishment and expansion, which is expected to be completed by May 2003. These NGL assets also include the Almeda fractionator, which has fractionation capacity of 24 MBbls/d. The average utilization rate for the Almeda fractionator for the year ended December 31, 2002 was less than two percent due to the portions that were shut-in pending refurbishment and expansion. The average utilization rate for the Almeda fractionator for years ended December 31, 2001 and 2000 was 32 percent and 26 percent.

Offshore Oil Pipeline Systems

We own interests in three offshore oil pipeline systems, which extend over 340 miles and have a combined capacity of approximately 635 MBbls/d of oil with the addition of pumps and the use of friction reducers. In addition to being strategically located in the vicinity of some prolific oil-producing regions in the Gulf of Mexico, our oil pipeline systems are parallel to and interconnect with key segments of some of our natural gas pipeline systems and offshore platforms, which contain separation and handling facilities. This distinguishes us from our competitors by allowing us to provide some producing properties with a unique single point of contact through which they may access a wide range of midstream services and assets.

The following table and discussions describe our offshore oil pipelines.

	POSEIDON	ALLEGHENY	TYPHOON(1)
Ownership interest	36%	100%	100%
In-service date	1996	1999	2001
Approximate capacity(2)	400	135	100
Aggregate miles of pipe	288	43	16
Average throughput for the years ended:(3)			
December 31, 2002	49	18	28
December 31, 2001	56	13	23
December 31, 2000	57	18	--

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(1) The average throughput reflects 100 percent of the throughput. We acquired the Typhoon oil pipeline together with the other San Juan assets in November 2002, from subsidiaries of El Paso Corporation.

(2) All capacity measures are on a MBbls/d basis, and with respect to Poseidon, include 100 percent of the design capacity. Poseidon and Allegheny's capacity measures can be achieved with the addition of pumps and use of

friction reducers.

(3) All average throughput measures are on a MBbls/d basis, and with respect to Poseidon, net to our interests.

Poseidon System. Poseidon is a major offshore sour crude oil pipeline system that we built in response to the increased demand for additional sour crude oil pipeline capacity in the central Gulf of Mexico. The Poseidon system is owned by Poseidon Oil Pipeline Company, L.L.C., in which we own a 36 percent membership interest. We began operating the Poseidon system in January 2001. The Poseidon system consists of:

- 117 miles of 16 to 20-inch diameter pipeline extending from our 50 percent owned Garden Banks 72 platform to our 50 percent owned Ship Shoal 332 platform;

- 122 miles of 24-inch diameter pipeline extending from the Ship Shoal 332 platform to Houma, Louisiana;

- 32 miles of 16-inch diameter pipeline extending from Ewing Bank Block 873 to the 24-inch pipeline in the area of South Timbalier Block 212; and

- 17 miles of 16-inch pipeline extending from Garden Banks Block 260 to South Marsh Island Block 205.

Poseidon Oil Pipeline Company, L.L.C. is party to a revolving credit agreement that requires it to maintain a debt service reserve of two quarters' interest. Other than that debt service reserve amount and any other reserve amounts agreed upon by more than a 72 percent interest of Poseidon's members, Poseidon distributes monthly all of its available cash to its members. Poseidon is managed by a management committee consisting of representatives from each of its members.

Allegheny System. Our Allegheny system is an offshore crude oil system consisting of 43 miles of 14-inch diameter pipeline that connects the Allegheny field in the Green Canyon area of the Gulf of Mexico with Poseidon at our 50 percent owned Ship Shoal 332 platform. Oil production from the Allegheny field is committed to this system.

Typhoon Oil Pipeline. The Typhoon oil pipeline is an offshore crude oil pipeline consisting of 16 miles of 12-inch diameter pipeline that connects the Typhoon field discovery in the Green Canyon area of the Gulf of Mexico to the Shell Boxer platform, a delivery point into the Poseidon pipeline.

NGL storage

Hattiesburg Propane Storage. In January 2002, we acquired a 3.3 MMBbl propane storage business and leaching operation located in Hattiesburg, Mississippi from Suburban Propane, L.P. for approximately $8 million. As part of that transaction, we entered into a long-term propane storage agreement with Suburban Propane, L.P. for a portion of the acquired propane storage capacity.

Anse La Butte NGL Storage. In December 2001, we acquired Anse La Butte, a 3.2 MMBbl NGL multi-product storage facility near Breaux Bridge, Louisiana. As part of the transaction, we entered into long-term storage agreements with a third party and with El Paso Field Services, a subsidiary of El Paso Corporation, for a significant portion of the storage capacity.

Texas Leased NGL Storage Facilities. As part of the November 2002 San Juan assets acquisition, we acquired leases for three NGL storage facilities in Texas with aggregate capacity of approximately 18.1 MMBbls. The leases covering these facilities expire in 2006 and 2012.

Construction Projects

Marco Polo Project. We will construct and own a 36-mile, 14-inch oil pipeline to support the Marco Polo TLP. The oil pipeline will gather oil from the Marco Polo platform to our Allegheny pipeline in Green Canyon Block 164 with a maximum capacity of 120 MBbls/d. This pipeline is expected to be completed and placed in service in the first quarter of 2004, and is expected to cost $28 million to construct. As of December 31, 2002, we have spent approximately $1.3 million on this pipeline, which is in the development stage. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

Cameron Highway. In February 2002, we announced that we will build and operate the $458 million, 390-mile Cameron Highway oil pipeline with capacity of 500 MBbls/d, which is expected to be in service by the third quarter of 2004, and will provide producers with access to onshore delivery points in Texas. BP p.l.c., BHP Billiton and Unocal have dedicated 86,400 acres of property to this pipeline for the life of the reserves, including the acreage underlying their ownership interests in the Holstein, Mad Dog and Atlantis developments in the deeper water regions of the Gulf of Mexico. In October 2002, we entered into a non-binding letter of intent with Valero Energy Corporation under which Valero would acquire a 50 percent interest in the entity we form to construct, install and own this pipeline, which we will operate. The formation of this joint venture is subject to specific conditions set forth in the letter of intent, including negotiating and executing definitive documentation and obtaining mutually acceptable financing. We are contractually committed to the Cameron Highway project whether or not we obtain a partner or any other financing. We expect that a majority of the costs of this project will be funded through project financing, which we are currently negotiating. However, due to the volatility in the capital markets, it is conceivable that we could have to access capital from other sources, including cash from operations. We estimate that the majority of the capital outlay for the project will occur in 2003 and 2004. As of December 31, 2002, we have spent approximately $14.6 million related to this pipeline, which is in the development stage.

Markets and Competition

A base amount of utilization, 60% to 70%, of our Texas fractionation facilities will occur because most of the natural gas in south Texas must be processed in order to meet downstream pipeline specifications; however, full utilization of our fractionation facilities occurs only when the natural gas producer can receive more net proceeds by processing -- extracting and selling the NGL components contained in the raw natural gas -- than they would receive by merely selling the unprocessed natural gas stream. The spread between natural gas and NGL varies from time to time depending on a complex number of factors including (1) natural gas supply, demand and storage inventories, (2) NGL supply, demand and storage inventories and (3) crude oil prices. Given these intricate factors, the spread between natural gas and NGL prices exhibits weekly and monthly volatility. If a gas producer determines that this spread is too low, that producer will choose to use our facilities at only the minimum level required to meet downstream pipeline gas quality specifications. Regardless of the elections made by the producers, our fractionation facilities would continue to be operated, but at lower utilization, and we will continue to incur operating costs regardless of the utilization level.

Our NGL pipelines provide the sole outlet for natural gas liquids from the seven natural gas processing plants in south Texas owned by subsidiaries of El Paso Corporation. As is the case for the Texas fractionation facilities, the volume of NGL carried by these pipelines is dependent upon the volume of natural gas available for processing and the economics of extraction of natural gas liquids viewed by the natural gas producers. The principal competition for our pipelines that carry NGL from the Texas fractionation facilities include pipeline systems owned by petrochemical companies and other midstream entities. While the petrochemical companies may use their pipeline systems to carry NGL for third parties, their primary use of these assets are to secure hydrocarbon feedstocks for their own plant complexes along the Texas Gulf Coast. In general, our NGL pipelines are well positioned to deliver products such as propane and butane from our Texas fractionation facilities to key end-use markets such as refiners and petrochemical facilities along the Texas Gulf Coast.

In connection with our February 2001 acquisition of EPN Texas, we entered into a 20-year fee-based transportation and fractionation agreement and dedicated 100 percent of the capacity of our fractionation facilities to a subsidiary of El Paso Corporation. In this agreement, all of the NGL derived from processing operations at seven natural gas processing plants in south Texas owned by subsidiaries of El Paso Corporation are delivered to our NGL transportation and fractionation facilities. Effectively, we will 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. El Paso Corporation's subsidiary will bear substantially all of the risks and rewards associated with changes in the commodity prices for NGL.

Our offshore oil pipeline systems were built as a result of the need for additional crude oil capacity to transport new deepwater oil production to shore. Our principal competition includes other oil pipeline systems, built, owned and operated by producers to handle their own production and, as capacity is available, production for others. Our oil pipelines compete for new production on the basis of geographic proximity to the production, cost of connection, available capacity, transportation rates and access to onshore markets. In addition, the ability of our pipelines to access future reserves will be subject to our ability, or the producers' ability, to fund the significant capital expenditures required to connect to the new production.

A substantial portion of the revenues generated by our oil pipeline systems are attributed to production from reserves committed under long-term contracts for the productive life of the relevant field, typically involving both firm and interruptible components. Nonetheless, these reserves and other reserves that may become available to our pipeline systems are depleting assets and will be produced over a finite period. Each of our pipeline systems must access additional reserves to offset the natural decline in production from existing connected wells or the loss of any other production to a competitor. Our oil systems are not subject to regulatory rate-making authority, and the rates we charge for our services are dependent on the quality of the service required by the customer and the amount and term of the reserve commitment by the customer. Generally, we receive a price per barrel of oil or water handled.

For a discussion of our significant customers, see Item 8, Financial Statements and Supplementary Data, Note 13.

Regulatory Environment

Our offshore oil pipeline systems are subject to federal regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico. Each of the oil pipeline systems has continuing programs of inspection and compliance designed to keep all of our facilities in compliance with pipeline safety and pollution control requirements. We believe that our oil pipeline systems are in material compliance with the applicable requirements of these regulations.

In addition, our NGL assets are subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These assets have a continuing program of inspection designed to keep all of our assets in compliance with pollution control and pipeline safety requirements. We believe that these NGL assets are in compliance with the applicable requirements of these regulations. Our NGL pipelines in Texas, some of which we classified as common carriers, are regulated by the Texas Railroad commission.

Environmental

Our oil and natural gas logistics operations are subject to various safety and environmental statutes, including: the Outer Continental Shelf Act, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and similar state statutes. For a discussion of environmental regulations, see Environmental -- Specific Regulations.

Maintenance

Each of our pipeline systems, our fractionation facilities and our processing facilities require regular maintenance. The interior of the EPN Texas, Allegheny, Typhoon and Poseidon pipelines is maintained through the regular cleaning of the line of liquids that collect in the pipelines. Corrosion inhibitors are also injected into all of the systems through the flow stream on a continuous basis. Our Allegheny and Poseidon oil pipeline systems include platforms that are manned on a continuous basis. The personnel on board these platforms are responsible for site maintenance, operations of the platform facilities, measurement of the oil stream at the source of production and corrosion control.

NATURAL GAS STORAGE

We own the Petal and Hattiesburg salt dome natural gas storage facilities located in Mississippi, which are strategically situated to serve the Northeast, Mid-Atlantic and Southeast natural gas markets. In June 2002, we completed a 8.9 Bcf (6.3 Bcf working capacity) expansion of our Petal facility, including a withdrawal facility and a 20,000 horsepower compression station and a 60-mile takeaway pipeline, including a 9,000 horsepower compression station. These two facilities have a combined current working capacity of 13.5 Bcf, and are capable of delivering in excess of 1.2 Bcf/d of natural gas into five interstate pipeline systems: Transco, Destin Pipeline, Gulf South Pipeline, Southern Natural Gas Pipeline and Tennessee Gas Pipeline. Each of these facilities is capable of making deliveries at the high rates necessary to satisfy peak requirements in the electric generation industry. As a result of the successful completion of our Petal expansion and a general increase in the storage business, we have experienced interest from third parties in acquiring an ownership interest in our Petal and Hattiesburg facilities. We are evaluating all our options relating to these facilities, including discussions with various third parties to evaluate their level of interest. At this time, we cannot predict what changes, if any, in our ownership of these facilities will result from our evaluation.

	HATTIESBURG	PETAL
Approximate acres	73	76
Year end 2002 working gas capacity (Bcf)	4.0	9.5

	HATTIESBURG			PETAL		
	2002	2001	2000	2002	2001	2000
Firm storage						
Average working gas capacity available (Bcf)	4.1	4.3	4.3	5.9	3.2	3.2
Average firm subscription (Bcf)	4.1	4.3	4.3	5.6	2.6	2.7
Commodity volumes (Mdth/d)	71.0	46.0	14.0	56.0	17.0	5.0
Interruptible storage						
Contracted volumes (Bcf)	0.1	0.1	0.5	0.1	0.3	--
Commodity volumes (Mdth/d)	1.0	47.0	--	31.0	5.0	--

The Hattiesburg facility is outside of Hattiesburg, Mississippi, and consists of three high-deliverability natural gas storage caverns. The facility has an injection capacity in excess of 175 MMcf/d of natural gas and a withdrawal capacity in excess of 400 MMcf/d of natural gas. The Hattiesburg capacity is currently fully subscribed, primarily with eleven long-term contracts expiring between 2005 and 2006.

The Petal facility is less than one mile from the Hattiesburg facility and consists of two high-deliverability natural gas storage caverns. The Petal facility has an injection capacity in excess of 430 MMcf/d of natural gas and a withdrawal capacity of 865 MMcf/d of natural gas. The Petal capacity is 91 percent subscribed, with 7.0 Bcf dedicated under a 20-year fixed-fee contract to a subsidiary of The Southern Company, one of the largest producers of electricity in the United States, and 1.65 Bcf subscribed to BP Energy Company.

The ability of the facilities to handle these high levels of injections and withdrawals of natural gas makes the facilities well suited for customers who desire the ability to meet short duration load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. The high injection and withdrawal rates also allow customers to take advantage of favorable natural gas prices and also provide customers the opportunity to quickly respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facility. The characteristics of the salt domes at the facilities permit sustained periods of high delivery, the ability to quickly switch from full injection to full withdrawal and the ability to provide an impermeable storage medium.

In addition to our Petal and Hattiesburg facilities, we have the exclusive right to use the Wilson natural gas storage facility under an operating lease that expires in January 2008 and, subject to certain conditions, has one or more optional renewal periods of five years each at fair market rent at the time of renewal. The Wilson facility is comprised of 62 acres, in Wharton County, Texas, and consists of four caverns with a working gas capacity of 6.4 Bcf. The facility has an injection capacity of 150 to 360 MMcf/d of natural gas and a maximum withdrawal capacity of 800 MMcf/d of natural gas. The Wilson capacity is currently 91 percent subscribed with long-term contracts expiring between 2006 and 2007.

Markets and Competition

Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our Petal and Hattiesburg natural gas storage facilities are located in an area in Mississippi that can effectively service the Northeastern, Mid-Atlantic and Southeastern natural gas markets, and the facilities have the ability to deliver all of their stored natural gas within a short timeframe. Our natural gas storage facilities compete with other means of natural gas storage, including other salt dome storage facilities, depleted reservoir facilities, liquified natural gas and pipelines.

Most of the capacity relating to the Petal facility is dedicated under a 20-year, fixed-fee contract. Most of the contracts relating to our Hattiesburg natural gas storage assets are long term, expiring between 2005 and 2006. We believe that the existence of these long-term contracts for storage, and the location of our natural gas storage facilities should allow us to compete effectively with other companies who provide natural gas storage services. We believe that many of our natural gas storage contracts will be renewed, although we also expect that once these firm storage contracts have expired, we will experience greater competition for providing storage services. The competition we experience will be dependent upon the nature of the natural gas storage market existing at that time. In addition to long-term contracts, we actively market interruptible storage services at the Petal facility to enhance our revenue generating ability beyond the firm storage contracts.

For a discussion of our significant customers see Item 8, Financial Statements and Supplementary Data, Note 13.

Regulatory Environment

Our Hattiesburg facility is a regulated utility under the jurisdiction of the Mississippi Public Service Commission. Accordingly, the rates charged for natural gas storage services are subject to approval from this agency. The present rates of the firm long-term contracts for natural gas storage in the Hattiesburg facility were approved in 1990. A portion of its natural gas storage business is also subject to a limited rate jurisdiction certificate issued by FERC. The certificate authorizes us to provide natural gas storage services that may be ultimately consumed outside of Mississippi. Our Petal facility is subject to regulation under the Natural Gas Act of 1938, as amended, and to the jurisdiction of FERC. The Petal facility currently holds certificates of public convenience and necessity that permits us to charge market-based rates. The natural gas pipeline industry has historically been heavily regulated by federal and state government and we cannot predict what further actions FERC, state regulators, or federal and state legislators may take in the future.

In June 2002, the Petal facility filed with the FERC a certificate application to add additional gas storage and injection capacity to Petal's storage system. The filing included a new storage cavern with a working gas storage capacity of 5 Bcf, the conversion and enlargement of an existing subsurface brine storage cavern to a gas storage cavern with a working capacity of up to 3 Bcf and related surface facilities, natural gas, water and brine transmission lines. In February 2003, the FERC approved the facilities proposed by Petal.

The FERC has issued two NOPRs that may affect our Petal operations. See Item 8, Financial Statements and Supplementary Data, Note 10.

The Wilson natural gas storage facility is regulated by the Railroad Commission of Texas and its Section 311 services are regulated by the FERC.

Environmental

Our natural gas storage operations are subject to various safety and environmental statutes, including: the Natural Gas Act, the Natural Gas Policy Act, the Hazardous Materials Transportation Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Clean Water Act, the Endangered Species Act, the Occupational Safety and

Health Act, the Emergency Planning and Community Right-to-Know Act, and similar state statutes. For a discussion of environmental regulation, see Environmental -- Specific Regulations.

Maintenance

Our storage facilities are manned on a continuous basis by personnel responsible for maintenance and operations. Maintenance of the surface facilities is an ongoing process and is performed per equipment manufacturers' recommendations, established preventative maintenance schedules or as required by operating conditions. Maintenance of the Hattiesburg and Petal storage caverns includes a mechanical integrity test performed every five years as required by the Mississippi State Oil and Gas Board. Maintenance of the Wilson storage caverns and brine water disposal caverns includes a mechanical integrity test performed every five years for the storage caverns and every three years for the disposal caverns, as constituted by the Railroad Commission of Texas.

PLATFORM SERVICES

Offshore platforms are critical components of the offshore infrastructure in the Gulf of Mexico, supporting drilling and production operations, and therefore play a key role in the overall development of offshore oil and natural gas reserves. Platforms are used to:

- interconnect the offshore pipeline grid;

- provide an efficient means to perform pipeline maintenance;

- locate compression, separation, production handling and other facilities; and

- conduct drilling operations during the initial development phase of an oil and natural gas property.

We have interests in six multi-purpose offshore hub platforms in the Gulf of Mexico, including the completion of the Falcon Nest fixed leg platform which we brought on line in March 2003. These platforms were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities. Through these facilities, we are able to provide a variety of midstream services to increase deliverability for, and attract new volumes into, our offshore pipeline systems. The following table and discussions describe our platforms.

	EAST CAMERON 373	VIOSCA KNOLL 817	SHIP SHOAL 331(1)	GARDEN BANKS 72	SHIP SHOAL 332(2)	FALCON NEST
Ownership interest	100%	100%	100%	50%	50%	100%
In-service date	1998	1995	1994	1995	1985	2003
Water depth (in feet)	441	671	376	518	438	389
Acquired (A) or constructed (C)	C	C	A	C	A	C
Approximate handling capacity:						
Natural gas (MMcf/d)	190	140	--	80	150	400
Oil and condensate (MBbls/d)	5	5	--	55	12	2

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(1) The Ship Shoal 331 platform is currently used as a satellite landing area. All products transported to the Ship Shoal 331 platform are processed on the Ship Shoal 332 platform.

(2) We sold 50 percent of our interest in the Ship Shoal 332 platform in January 2001.

East Cameron 373. The East Cameron 373 platform is located at the south end of the central leg of Shell's Stingray system. The platform serves as the host for Kerr-McGee Corporation's East Cameron Block 373 production and as the landing site for Garden Banks Blocks 108, 152, 200 and 201 production and the East Cameron Blocks 374 and 380 production.

Viosca Knoll 817. The Viosca Knoll 817 platform is centrally located on the Viosca Knoll system. The platform serves as a base for landing deepwater production in the area, including ExxonMobil's, Shell's, and BP's Ram Powell development. A 7,000 horsepower compressor on the platform facilitates deliveries from the

Viosca Knoll system to multiple downstream interstate pipelines. The platform is also used as a base for oil and natural gas production from our Viosca Knoll Block 817 lease and Walter Oil and Gas' Viosca Knoll 862 lease.

Ship Shoal 331. The Ship Shoal 331 platform is a production facility located approximately 75 miles off the coast of Louisiana. Maritech Resources, Inc. has rights to utilize the platform pursuant to a production handling and use of space agreement.

Garden Banks 72. The Garden Banks 72 platform is located at the south end of the eastern leg of Shell's Stingray system and serves as the western-most termination point of the Poseidon system. The platform serves as a base for landing deepwater production from Newfield Exploration Inc.'s Garden Banks Block 161 development, LLOG Exploration Offshore's Garden Banks Block 205 lease and Amerada Hess Corporation's Garden Banks Block 158 lease. We also use this platform as the host for our Garden Banks Block 72 production and the landing site for production from our Garden Banks Block 117 lease located in an adjacent lease block.

Ship Shoal 332. The Ship Shoal 332 platform serves as a major junction platform for pipelines in the Allegheny and Poseidon systems.

Falcon Nest. In April 2002, we entered into an agreement to construct and own the $53 million Falcon Nest fixed-leg platform, together with related pipelines. Falcon Nest will process natural gas from Pioneer Natural Resources Company's and Mariner Energy, Inc.'s Falcon Field discovery in the Gulf of Mexico. The platform and related pipelines were installed at Mustang Island Block 103 in the northwest portion of the Falcon Field and commissioned in the first quarter of 2003 and natural gas began flowing to the platform from the Falcon Field in March 2003. Pioneer and Mariner have dedicated 69,120 acres of property, including acreage underlying their Falcon Field discovery, to this platform for the life of the reserves. As of December 31, 2002, we have spent approximately $31.0 million on this project. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

Construction Projects

Marco Polo Project. We are constructing the Marco Polo TLP with a maximum handling capacity of 120 MBbls/d of oil and 300 MMcf/d of natural gas. This TLP, which we expect to be in service in the fourth quarter of 2003, was designed and located to process oil and natural gas from Anadarko Petroleum Corporation's Marco Polo Field discovery in the Gulf of Mexico. Anadarko has dedicated 69,120 acres of property to this TLP, including the acreage underlying their Marco Polo Field discovery, for the life of the reserves. Anadarko will have firm capacity of 50 MBbls/d of oil and 150 MMcf/d of natural gas. The remainder of the platform capacity will be available to Anadarko for additional production and/or to third parties that have fields developed in the area. This TLP will be owned by Deepwater Gateway, L.L.C., our 50 percent owned joint venture with Cal Dive International, Inc., a leading energy services company specializing in subsea construction and well operations. We will operate Deepwater Gateway and the Marco Polo TLP will be operated by Anadarko. The total cost of the project is estimated to be $206 million, or approximately $103 million for our share. As of December 31, 2002, Deepwater Gateway has spent approximately $108.1 million on this TLP.

In August 2002, Deepwater Gateway obtained a $155 million project finance loan at a variable interest rate from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. The loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2002, Deepwater Gateway had $27 million outstanding under the project finance loan and has not paid us, our joint venture partner or any of our subsidiaries any distributions.

As of December 31, 2002, we have contributed $33 million, as our 50 percent share, to Deepwater Gateway, which amount satisfies our funding requirement related to the Marco Polo TLP. We expect that the remaining cost associated with the Marco Polo TLP will be funded through the $155 million project finance loan. This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. The loan agreement requires Deepwater Gateway to maintain a debt service reserve equal to six months' interest. Other than the debt service reserve and any other reserve amounts agreed upon by more than 66.7 percent majority interest of Deepwater Gateway's members, Deepwater Gateway will (after the project finance loan is either repaid or converted into a term loan) distribute any available cash to its members quarterly. Deepwater Gateway is not currently generating operating income or cash flow. Deepwater Gateway is managed by a management committee consisting of representatives from each of its members.

Markets and Competition

Our platforms are subject to similar competitive factors as our pipeline systems. These assets generally compete on the basis of proximity and access to existing reserves and pipeline systems, as well as costs and rates. Furthermore, competitors to these platforms may possess greater technical skill and capital resources than we have.

Maintenance

Each of our platforms requires regular maintenance. The platforms are painted to the waterline every three to five years to prevent atmospheric corrosion. Corrosion protection devices are also fastened to platform legs below the waterline to prevent corrosion. Remotely operated vehicles or divers inspect the platforms below the waterline generally every five years. Most of our platforms are manned on a continuous basis. The personnel on board these platforms are responsible for site maintenance, operations of the platform facilities, measurement of the oil and natural gas stream at the source of production and corrosion control.

OTHER

Currently, we own interests in five oil and natural gas properties located in waters offshore of Louisiana. Production is gathered, transported, and processed through our pipeline systems and platform facilities, and sold to various third parties and subsidiaries of El Paso Corporation. We intend to continue to concentrate on fee-based operations that traditionally provide more stable cash flow and de-emphasize our commodity-based activities, including exiting the oil and natural gas production business by not acquiring additional properties.

Producing Properties

The following table sets forth information regarding our producing properties as of December 31, 2002.

	GARDEN BANKS BLOCK 72	GARDEN BANKS BLOCK 73(1)	GARDEN BANKS BLOCK 117	VIOSCA KNOLL BLOCK 817(2)	WEST DELTA BLOCK 35(3)
Working interest.................	50%	--	50%	100%	38%
Net revenue interest.............	40.2%	2.5%	37.5%	80%	29.8%
In-service date..................	1996	2000	1996	1995	1993
Net acres........................	2,880	--	2,880	5,760	1,894
Distance offshore (in miles).....	120	115	120	40	10
Water depth (in feet)............	519	743	1,000	671	60
Producing wells..................	5	--	2	7	3
Cumulative production:					
Natural gas (MMcf)............	5,068	219	2,203	63,278	2,987
Oil (MBbls)...................	1,517	--	1,245	181	15

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(1) We own a 2.5 percent overriding interest in Garden Banks Block 73, which began producing in mid-2000 and continued producing through September 2001. The owner plans to plug and abandon this well in 2003.

(2) 25 percent of our 100 percent working interest in Viosca Knoll Block 817 is subject to a production payment that entitles holders to 25 percent of the proceeds from the production attributable to this working interest (after deducting all leasehold operating expenses, including platform access and production handling fees) until the holders have received the aggregate sum of $16 million. At December 31, 2002, the unpaid portion of the production payment obligation totaled $9.3 million.

(3) The West Delta Block 35 field commenced production in 1993, but our interest in this field was acquired in connection with El Paso Corporation's acquisition of our general partner in 1998. Production data is for the period from August 1998.

Acreage and Wells. The following table sets forth our developed and undeveloped oil and natural gas acreage as of December 31, 2002. Undeveloped acreage refers to those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether or not such acreage contains proved reserves. Gross acres in the following table refer to the number of acres in which a working interest is owned directly by us. The number of net acres is our fractional ownership of the working interest in the gross acres.

	GROSS	NET
Developed acreage..	4,872	3,576
Undeveloped acreage..	23,153	14,518
Total acreage..................................	28,025	18,094

Our gross and net ownership in producing wells in which a working interest is owned directly by us at December 31, 2002, is as follows:

	GROSS	NET
Natural gas..	11.0	

8.6
Oil...
6.0 3.0 ---- ----
Total... 17.0
11.6 ==== ====

We participated through our 38 percent non-operating working interest in a developmental well in West Delta Block 35 in 2001. As an operator, we have not drilled any exploratory or developmental wells since 1998, and we plan to spend $2.6 million in the next three years to develop our proved undeveloped reserves.

Net Production, Unit Prices and Production Costs

The following table sets forth information regarding the production volumes of, average unit prices received for, and average production costs for our oil and natural gas properties for the years ended December 31:

	OIL (MBBLS)			NATURAL GAS (MMCF)		
	2002	2001	2000	2002	2001	2000
Net production(1)	318	343	295	3,237	4,038	7,185
Average realized sales price(1)	$23.36	$23.47	$25.26	$ 3.12	$ 4.52	$ 1.86
Average segment realized production costs(2)	$15.01	$16.11	$10.87	$ 2.50	$ 2.68	$ 1.81

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(1) The information regarding net production and average realized sales prices includes overriding royalty interests. Net oil and natural gas production volumes from our overriding royalty interest in the Prince Field were approximately 50 MBbls and 37 MMcf in 2002 and 37 MBbls and 32 MMcf in 2001. We did not have any production volumes from our overriding royalty interest in the Prince Field in 2000. Average realized oil and natural gas sales prices for 2000 were impacted by hedging activities. Excluding our hedging activities, our average realized sales price would have been $28.12 for oil and $3.91 for natural gas in 2000.

(2) The components of average segment realized production costs, which consist of production expenses per unit of oil or natural gas produced, may vary substantially among wells depending on the methods of recovery employed and other factors. Our production expenses include third party transportation expenses, maintenance and repair, labor and utilities costs, as well as the cost of platform access fees paid by our oil and natural gas subsidiary, included in our oil and natural gas production segment, to subsidiaries included in our platforms segment. These platform access fees are eliminated in our consolidated financial statements. For the year 2002, these platform access fees were approximately $6.8 million and for each of the years 2001 and 2000, these platform access fees were approximately $10 million. On a consolidated basis our average realized production costs were as follows:

	OIL (MBBLS)			NATURAL GAS (MMCF)		
	2002	2001	2000	2002	2001	2000
Average consolidated realized production costs(1)	$7.13	$6.35	$4.23	$1.19	$1.06	$0.70

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(1) The increase in per unit production costs from year to year was a result of production declines coupled with higher offshore oil and natural gas field servicing and direct production costs.

The relationship between average sales prices and average production costs depicted by the table above is not necessarily indicative of true results of operations. For a discussion of oil and natural gas reserve information and estimated future net cash flows, see Item 8, Financial Statements and Supplementary Data, Note 16.

Markets and Competition

We are reducing our oil and natural gas production activities due to its higher risk profile, including risks associated with finding production and commodity prices. Accordingly, our focus is to maximize the production from our existing portfolio of oil and natural gas properties. As a result, the competitive factors that would normally impact exploration and production activities are not as pertinent to our operations. However, the oil and natural gas industry is intensely competitive, and we do compete with a substantial number of other companies, including many with larger technical staffs and greater financial and operational resources in terms of accessing transportation, hiring personnel, marketing production and withstanding the effects of general and industry-specific economic changes.

Regulatory Environment

Our production and development operations are subject to regulation at the federal and state levels. Regulated activities include:

- requiring permits for the drilling of wells;

- maintaining bonds and insurance requirements in order to drill or operate wells;

- drilling and casing wells;

- using and restoring the surface of properties upon which wells are drilled; and

- plugging and abandoning of wells.

Our production and development operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells that may be drilled, the levels of production, and the pooling of oil and natural gas properties.

We presently have interests in, or rights to, offshore leases located in federal waters. Federal leases are administered by the Minerals Management Service (MMS). Individuals and entities must qualify with the MMS prior to owning and operating any leasehold or right-of-way interest in federal waters. Qualification with the MMS generally involves filing certain documents and obtaining an area-wide performance bond and/or supplemental bonds representing security for facility abandonment and site clearance costs.

Environmental

Our production and development operations are subject to various safety and environmental statutes, including: the Outer Continental Shelf Act, the Hazardous Materials Transportation Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act and similar state statutes. For a discussion of environmental regulations, see Environmental -- Specific Regulations.

Operating Environment

Our oil and natural gas production operations are subject to all of the operating risks normally associated with the production of oil and natural gas, including blowouts, cratering, pollution and fires, each of which could result in damage to life or property. Offshore operations are subject to usual marine perils, including hurricanes and other adverse weather conditions, and governmental regulations, including interruption or termination by governmental authorities based on environmental and other considerations. In accordance with customary industry practices, we maintain broad insurance coverage with respect to potential losses resulting from these operating hazards.

ENVIRONMENTAL

GENERAL

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.

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. A description of our environmental matters is included in Item 8, Financial Statements and Supplementary Data, Note 10.

SPECIFIC REGULATIONS

Pipelines. Several federal and state environmental statutes and regulations may pertain specifically to the operations of our pipelines. The Hazardous Materials Transportation Act regulates materials capable of posing an unreasonable risk to health, safety and property when transported in commerce. The Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act authorize the development and enforcement of regulations governing pipeline transportation of natural gas and NGL. Although federal jurisdiction is exclusive over regulated pipelines, the statutes allow states to impose additional requirements for intrastate lines if compatible with federal programs. New Mexico, Texas and Louisiana have developed regulatory programs that parallel the federal program for the transportation of natural gas and NGL by pipelines.

Solid Waste. The operations of our pipelines and plants may generate both hazardous and nonhazardous solid wastes that are subject to the requirements of the Federal Solid Waste Disposal Act, Resource Conservation and Recovery Act, or RCRA, and their regulations, and similar state statutes and regulations. Further, it is possible that some wastes that are currently classified as nonhazardous, via exemption or otherwise, perhaps including wastes currently generated during pipeline operations, may, in the future, be designated as "hazardous wastes," which would then be subject to more rigorous and costly treatment, storage, transportation, and disposal requirements. Such changes in the regulations may result in additional expenditures or operating expenses by us.

Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, and comparable state statutes, also known as "Superfund" laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that cause or contribute to the release of a "hazardous substance" into the environment. These persons include the current owner or operator of a site, the past owner or operator of a site, and companies that transport, dispose of, or arrange for the disposal of the hazardous substances found at the site. CERCLA also authorizes the EPA or state agency, and in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Despite the "petroleum exclusion" of CERCLA Section 101(14) that currently encompasses natural gas, we may nonetheless handle "hazardous substances" within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations.

Air. Our operations may be subject to the Clean Air Act, or CAA, and similar state statutes. The 1990 CAA amendments and accompanying regulations, state or federal, may impose certain pollution control requirements with respect to air emissions from operations, particularly in instances where a company constructs a new facility or modifies an existing facility. We may also be required to incur certain capital expenditures in the next several years estimated to be approximately $10 million in aggregate for the years 2003 through 2007 for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

Water. The Federal Water Pollution Control Act, or FWPCA or Clean Water Act, imposes strict controls against the unauthorized discharge of pollutants, including produced waters and other oil and natural gas wastes into navigable waters. The FWPCA provides for civil and criminal penalties for any unauthorized discharges of oil and other substances and, along with the Oil Pollution Act of 1990, or OPA, imposes substantial potential liability for the costs of oil or hazardous substance removal, remediation and damages. Similarly, the OPA imposes liability for the discharge of oil into or upon navigable waters or adjoining shorelines. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of an unauthorized discharge of pollutants into state waters.

Communication of Hazards. The Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and comparable state statutes require those entities that operate facilities for us to organize and disseminate information to employees, state and local organizations, and the public about the hazardous materials used in our operations and our emergency planning.

EMPLOYEES

Neither we nor El Paso Energy Partners Company, our general partner, has any employees. We reimburse our general partner for all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on behalf of, us, including expenses incurred by us under the general and administrative services agreement.

AVAILABLE INFORMATION

Our website is http://www.elpasopartners.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after these reports are filed with the Securities and Exchange Commission (SEC). Information contained on our website is not part of this report.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business.

We believe we have satisfactory title to the properties owned and used in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions that do not materially detract from the value of the property, or the interests of the property, or the use of such properties in our businesses. We believe that our physical properties are adequate and suitable for the conduct of our business in the future.

Substantially all of our assets and the assets of our subsidiaries (other than our unrestricted subsidiaries, Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and EPN Arizona Gas, L.L.C.), together with our general partner's general and administrative services agreement, are pledged as collateral under our credit facility, the EPN Holding term credit facility and our senior secured acquisition term loan. We repaid the senior secured acquisition term loan in March 2003 with proceeds from an issuance of $300 million 8 1/2% Senior Subordinated Notes, which are unsecured obligations of ours and our guarantor subsidiaries. In addition, our Poseidon and Deepwater Gateway joint ventures currently have credit facilities or credit agreements under which substantially all of their assets are pledged. For a discussion of our credit facilities, see Item 8, Financial Statements and Supplementary Data, Note 6.

ITEM 3. LEGAL PROCEEDINGS

See Item 8, Financial Statements and Supplementary Data, Note 10.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S UNITS AND RELATED UNITHOLDER MATTERS

Our common units are traded on the New York Stock Exchange (NYSE) under the symbol "EPN". As of March 24, 2003, there were 726 holders of record of common units and the closing price on the NYSE for common units was $31.10 per unit.

The following table reflects the high and low sales prices for common units based on the daily composite listing of unit transactions for the New York Stock Exchange and cash distributions declared per common unit during those periods.

	COMMON UNITS HIGH	COMMON UNITS LOW	DISTRIBUTIONS DECLARED PER UNIT COMMON
2002			
Fourth Quarter	$32.7000	$26.0000	$0.6750
Third Quarter	35.8000	20.5000	0.6500
Second Quarter	38.6800	29.9900	0.6500
First Quarter	38.5400..	31.6500	0.6250
2001			
Fourth Quarter	$42.1000	$30.7500	$0.6125
Third Quarter	40.4500	30.8000	0.5750
Second Quarter	35.5000	29.5700	0.5750
First Quarter	33.9900	25.5000	0.5500

In January 2003, we declared a quarterly distribution of $0.6750 per common unit which was paid on February 15, 2003, to unitholders of record on January 31, 2003. Our quarterly distribution rate represents an annual distribution rate of $2.70 per unit, up $0.20 compared to the annual rate of $2.50 declared in the fourth quarter of 2001.

CASH DISTRIBUTIONS

We make quarterly distributions of 100 percent of our available cash, as defined in our partnership agreement, to our unitholders and to our general partner. Our available cash consists generally 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 that it determines are necessary or appropriate to properly conduct our business. 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 any of our agreements or obligations.

The holders of common units and our general partner are not entitled to arrearages of minimum quarterly distributions. Our distributions are effectively made 99 percent to limited unitholders and one percent to our general partner, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Incentive distributions to our general partner increase to 14 percent, 24 percent and 49 percent based on incremental distribution thresholds. Since 1998, quarterly distributions to common unitholders have been in excess of the highest incentive threshold of $0.425 per unit, and as a result, our general partner has received 49 percent of the incremental amount. For the year ended December 31, 2002, we paid $111.8 million in distributions to our common unitholders, including El Paso Corporation, and $42.7 million to our general partner related to incentive distributions as well as our general partner's one percent income distribution.

We issued Series B preference units in 2000 and Series C units in November 2002. The issuance of these units may effect our payment of distributions. See Series B Preference Units and Series C Units below for a discussion of these units. Also, see Item 8, Financial Statements and Supplementary Data, Note 8, for a discussion relating to cash distributions.

RECENT OFFERINGS OF COMMON UNITS

In April 2002, we completed simultaneous offerings of 4,083,938 common units, which included a public offering of 3,000,000 common units and a private offering at the same unit price of 1,083,938 common units to our general partner (pursuant to our general partner's anti-dilution right under our partnership agreement) which was an exempt transaction under Section 4(2) of the Securities Act of 1933 as a transaction not involving a public offering. We used the net cash proceeds of approximately $149 million to reduce indebtedness under the EPN Holding term credit facility. Also in April 2002, we issued in a private offering 159,497 common units at the then-current market price of $37.74 per unit to a subsidiary of El Paso Corporation as partial consideration for our acquisition of the EPN Holding assets. In addition, our general partner contributed approximately $0.6 million in cash to us in order to maintain its one percent capital account balance.

In October 2001, we completed simultaneous offerings 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 (pursuant to our general partner's anti-dilution right under our partnership agreement) which was an exempt transaction under Section 4(2) of the Securities Act of 1933 as a transaction not involving a public offering. We used the net cash proceeds of approximately $212 million to redeem 44,608 Series B preference units with an aggregate liquidation value of $50 million and to reduce indebtedness under our revolving credit facility by $162 million. In addition, our general partner contributed $2.1 million in cash to us in order to satisfy its one percent capital 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 that included 600,000 common units to cover over-allotments for the underwriters. We used the net cash proceeds of approximately $101 million from the offering 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.

SERIES B PREFERENCE UNITS

In August 2000, we issued to a subsidiary of El Paso Corporation 170,000 cumulative redeemable Series B preference units, with a value of $170 million, in exchange for the Petal and Hattiesburg natural gas storage businesses. These 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. The preference units contain no mandatory redemption obligation, but may be redeemed at our option at any time. The issuance of these preference units was an exempt transaction under Section 4(2) of the Securities Act of 1933 as a transaction not involving a public offering. In October 2001, we redeemed 44,608 of the Series B preference units for their liquidation value of $50 million, bringing the total number of units outstanding to 125,392. As of December 31, 2002, the liquidation value of the outstanding Series B preference units was approximately $158 million.

SERIES C UNITS

In November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of Series C units at a price of $32 per unit, $350 million in the aggregate, as part of our consideration paid for the San Juan assets. The issuance of the Series C units was an exempt transaction under Section 4(2) of the Securities Act of 1933 as a transaction not involving a public offering. The Series C units are similar to our existing common units, except that the Series C units are non-voting. After April 30, 2003, the holder of Series C units will have the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit will convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C units will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate can increase on April 30, 2004, to 110 percent of the common unit distribution rate and on April 30, 2005, to 115 percent of the common unit distribution rate. Since all of the outstanding Series C units are owned by one party, there is no market for those units.

EQUITY COMPENSATION PLANS

Refer to the information included in Item 12, Security Ownership of Management, regarding securities authorized for issuance under equity compensation plans.

ITEM 6. SELECTED FINANCIAL DATA

	YEAR ENDED DECEMBER 31,				
	2002	2001	2000	1999	1998
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)				
Operating Results Data(1):					
Operating revenues(2)..............	$ 467,918	$193,406	$112,415	$63,659	$48,731
Income from continuing operations......................	92,552	54,052	20,749	18,817	746
Basic and diluted income (loss) from continuing operations per common unit(3)..................	0.80	0.35	(0.02)	(0.34)	0.02
Distributions per common unit......	2.60	2.31	2.15	2.10	2.08
Distributions per preference unit(4).........................	--	--	0.83	1.10	1.83

	AS OF DECEMBER 31,				
	2002	2001	2000	1999	1998
	(IN THOUSANDS)				
Financial Position Data(1):					
Total assets.......................	$3,130,896	$1,357,420	$869,471	$583,585	$442,726
Revolving credit facility..........	491,000	300,000	318,000	290,000	338,000
Senior secured term loans(5).......	557,500	--	--	--	--
Limited recourse term loan(6)......	--	95,000	45,000	--	--
Long-term debt(7)..................	857,786	425,000	175,000	175,000	--
Partners' capital(8)...............	949,852	500,726	311,071	96,489	82,896

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(1) Our operating results and financial position reflect the acquisitions of:
- the San Juan assets in November 2002;
- the EPN Holding assets in April 2002;
- the Chaco plant and the remaining 50 percent interest we did not already own in Deepwater Holdings in October 2001;
- EPN Texas in February 2001;
- the Petal and Hattiesburg natural gas storage facilities in August 2000;
- EPIA in March 2000; and
- an additional 49 percent interest in Viosca Knoll in June 1999.

The acquisitions were accounted for as purchases and therefore operating results of these acquired entities are included in our results prospectively from the purchase date. In addition, operating results and financial position reflect the sale of our and Deepwater Holdings' interests in several offshore Gulf of Mexico assets in January and April of 2001 as a result of an FTC order related to El Paso Corporation's merger with The Coastal Corporation.

(2) As a result of the disposition of our Prince assets in April 2002, the results of operations for these assets have been accounted for as discontinued operations and their related revenue has been excluded from operating revenues from their in-service date of September 2001 to their disposal date of April 2002. Operating revenues for 1999 and 1998 have been

restated to exclude earnings from unconsolidated affiliates.

(3) Reflects our 1999 adoption of a preferable accounting method for allocating partnership income to our general partner and our preference and common unitholders. 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. 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.

(4) In October 2000, all publicly held preference units were converted into common units or redeemed.

(5) The increase in 2002 reflects:

- $160 million EPN Holding term credit facility;
- $160 million senior secured term loan; and
- $237.5 million senior secured acquisition term loan.

(6) The balance in 2001 and 2000 relates to a project finance loan to build the Prince TLP in the Prince Field. With the completion of the Prince TLP, we converted the project finance loan to a limited recourse loan in December 2001. In connection with the EPN Holding asset acquisition, we repaid this loan in full in April 2002.

(7) The increase in 2002 reflects the issuance of our $200 million 10 5/8% Senior Subordinated Notes in November 2002 and the issuance of our $230 million 8 1/2% Senior Subordinated Notes in May 2002. The increase in 2001 reflects the issuance of our $250 million 8 1/2% Senior Subordinated Notes in May 2001. The increase in 1999 reflects the issuance of our $175 million 10 3/8% Senior Subordinated Notes in May 1999.

(8) Reflects the issuance of:

- 10.9 million Series C units acquired by a subsidiary of El Paso Corporation in November 2002;
- 4.1 million common units, which included 1.1 million common units purchased by an affiliate of our general partner in April 2002;
- 5.6 million common units, which included 1.5 million common units purchased by an affiliate of our general partner in October 2001;
- 2.3 million common units in March 2001;
- $170 million Series B preference units to a subsidiary of El Paso Corporation in August 2000; and
- 4.6 million common units in July 2000.

In addition, we redeemed $50 million liquidation value of our Series B preference units in October 2001.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

GENERAL

Our objective is to operate as a growth-oriented master limited partnership (MLP) with a focus on increasing our cash flow, earnings and return to our unitholders by becoming one of the industry's leading providers of midstream energy services. Our strategy is to maintain and grow a diversified, balanced base of strategically located and efficiently operated midstream energy assets with stable and long-term cash flows. We own or have interests in:

- over 15,700 miles of natural gas gathering and transportation pipelines with capacity of over 10.3 Bcf/d;

- over 340 miles of offshore oil pipelines with capacity of 635 MBbls/d;

- over 1,000 miles of NGL pipelines with varying capacity of up to 38 MBbls/d;

- five processing/treating plants with capacity of over 1.4 Bcf/d of natural gas and 50 MBbls/d of NGL;

- four NGL fractionating plants with capacity of 120 MBbls/d of NGL;

- five NGL storage facilities with aggregate capacity of over 24 MMBbls;

- three natural gas storage facilities with aggregate working gas capacity of over 19 Bcf; and

- six offshore hub platforms, including the Falcon nest platform which we brought online in March 2003.

In addition, we currently have midstream projects underway in the Gulf of Mexico with gross estimated capital costs of approximately $904 million, including 426 miles of oil pipeline, 202 miles of natural gas pipeline and two platforms, including the Falcon Nest platform which was completed in March 2003.

Our strategy contemplates substantial growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets, while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively, diversify our asset portfolio and, thereby, provide more stable cash flow. Consequently, to fully realize our strategy, we strive to access the right mix of short, medium, long-term and permanent capital on a cost-effective basis. We have expanded our credit facilities, obtained project financing and issued debt and equity securities to meet our financial needs over the past three years; however, we will need substantial new capital, including future periodic debt and equity offerings, to continue to finance our strategy. Significant milestones in the implementation of our strategy over the past three years include the following:

YEAR	TRANSACTION
2000	Acquired the natural gas pipeline system of EPIA; Placed the East Breaks joint venture pipeline system in service; Acquired the Petal and Hattiesburg salt dome natural gas storage facilities; Increased our ownership interest in Viosca Knoll

to 100 percent; 2001 Completed asset redeployment by selling several of our offshore Gulf of Mexico assets to third parties; Acquired the NGL transportation and fractionation assets of EPN Texas; Placed the Prince TLP facility into service; Increased our ownership in HIOS and East Breaks to 100 percent; Acquired interests in the titleholder of and other interests in the Chaco cryogenic natural gas processing plant;

YEAR	TRANSACTION
2002	Acquired Hattiesburg propane storage and leaching facility; Acquired substantial Texas and New Mexico midstream natural gas assets through the EPN Holding transaction (as part of this transaction, we disposed of the Prince TLP and our interests in the Prince Field); Completed the Petal expansion and takeaway pipeline construction; and Acquired the San Juan assets.

GENERAL PARTNER RELATIONSHIP

El Paso Energy Partners Company, a Delaware corporation, is our sole general partner. The business and affairs of our general partner are managed by a board of directors, comprised of two management directors who are also our executive officers and three independent directors who meet the independent director requirements established by the NYSE and the Sarbanes-Oxley Act of 2002. El Paso Energy Partners Company recently announced that the size of the board will be increased by the addition of two more independent directors. Through its board of directors, our general partner manages our day-to-day operations.

Our corporate governance structure and independence initiatives

The market is requesting that public companies institute dramatic governance changes designed to achieve independence, qualitatively and quantitatively. Some of the more immediate and fundamental proposed changes establish and require a higher standard for determining director independence and require a greater percentage of the members of the board to be independent. For example, under rules recently proposed by the NYSE:

- at least a majority of the members of the board of a listed company must be "independent directors;"

- each public company board must form several specific committees -- audit, governance and compensation -- that must be comprised entirely of independent directors; and

- the chairperson of the audit committee must be a "financial expert."

The Securities and Exchange Commission and the NYSE have developed definitions and other guidance to help establish minimum qualifications for "independent directors" and "financial experts." We are in compliance with all of these rules, regulations and standards as they apply to our general partner.

We continually strive to improve our corporate governance model. We recently identified and evaluated a number of changes that could be made to our corporate structure to better address potential conflicts of interest and to better balance the risks and rewards of significant relationships with our affiliates. With respect to the potential changes identified, which are referred to as Independence Initiatives, we have already implemented the following:

- reconstituted our board of directors with at least a majority of non-management, independent directors;

- established a governance and compensation committee of our board of directors consisting solely of independent directors; and

- significantly reduced the percentage of revenue we derive from affiliates of El Paso Corporation.

We are in the process of implementing the following Independence Initiatives:

- seeking financial assurances from El Paso Corporation and its affiliates regarding our existing customer/contractual relationships with them;

- adding two more independent directors to our board of directors;

- reorganizing our structure, further reducing the interrelationships with El Paso Corporation, into a Delaware limited liability company that will be required to have:

  - no material assets other than its interests in us;

  - no material operations other than those relating to our operations;

  - no material debt or other obligations other than those owed to us or our creditors;

  - no material liens other than those securing obligations owed to us or our creditors; and

  - no employees;

- changing our name; and

- negotiating several agreements that could partially mitigate our risks associated with our ongoing contractual arrangements with El Paso Corporation or any of its subsidiaries, including a master netting agreement and a resource support agreement.

Approval must be received from our general partner's board of directors and from El Paso Corporation prior to consummating the reorganization of the general partner and executing the master netting agreement and resource support agreement.

Under the partnership agreement, our general partner has the responsibility to, among other things, manage and operate our assets. In addition, under our partnership agreement, our general partner had agreed not to voluntarily withdraw as general partner on or prior to December 31, 2002. Now that this obligation of the general partner has expired, our general partner can withdraw with 90 days notice. We have no employees today, a condition that is common among MLPs. Although this arrangement has worked well for us in the past and continues to work well for us, we are evaluating the direct employment of the personnel who manage the day-to-day operations of our assets.

OUR RELATIONSHIP WITH EL PASO CORPORATION

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

- owns 100 percent of our general partner, which means that, historically, El Paso Corporation and its affiliates have employed the personnel who operate our businesses. We reimburse our general partner and its affiliates for the costs they incur on our behalf, and we pay our general partner its proportionate share of distributions -- relating to its one percent general partnership interest and the related incentive distributions -- we make to our partners each calendar quarter.

- is a significant stakeholder in us -- it owns approximately 26.5 percent, or 11,674,245, of our common units, all 10,937,500 of our newly issued Series C units, which we issued in November 2002 for $350 million, all 125,392 of our outstanding Series B preference units (with a liquidation value at December 31, 2002 of approximately $158 million), and our one percent general partner interest. As holders of some of our common units and all of our Series C units, subsidiaries of El Paso Corporation receive their proportionate share of distributions we make to our partners each calendar quarter.

- is a customer of ours. As with other large energy companies, we have entered into a number of contracts with El Paso Corporation and its affiliates.

- has in the past publicly announced its intention to use us as its primary vehicle for growth and development of its midstream energy business; however, El Paso Corporation is neither contractually nor legally bound to use us as its primary vehicle for growth and development of midstream energy assets, and may reconsider its relationship with us at any time, without notice.

Historically, we have entered into transactions with El Paso Corporation and its subsidiaries to acquire or sell assets. We have instituted specific procedures for evaluating and valuing our material transactions with El Paso Corporation and its subsidiaries. Before we consider entering into a transaction with El Paso

Corporation or any of its subsidiaries, we determine whether the proposed transaction (i) would comply with the requirements under our indentures and credit agreements, (ii) would comply with substantive law, and (iii) would be fair to us and our limited partners. In addition, our general partner's board of directors utilizes an Audit and Conflicts Committee comprised solely of independent directors. This committee:

- evaluates and, where appropriate, negotiates the proposed transaction;

- engages an independent financial advisor and independent legal counsel to assist with its evaluation of the proposed transaction; and

- determines whether to reject or approve and recommend the proposed transaction.

We will only consummate any proposed material acquisition or disposition with El Paso Corporation if, following our evaluation of the transaction, the Audit and Conflicts Committee approves and recommends the proposed transaction and our general partner's full board of directors approves the transaction.

Our relationship with El Paso Corporation has contributed significantly to our past growth, and we have important ongoing contractual arrangements with El Paso Corporation and some of its subsidiaries. However, we are a stand-alone operating company with significant assets and operations. Our assets, operations and financial condition are separate and independent from those of El Paso Corporation. Our credit facilities and other financing arrangements do not contain cross default provisions or other triggers tied to El Paso Corporation's financial condition or credit ratings. Nonetheless, due to our relationship with El Paso Corporation, adverse developments concerning El Paso Corporation could adversely affect us, even if we have not suffered any similar developments.

The outstanding senior unsecured indebtedness of El Paso Corporation has been downgraded to below investment grade and is currently rated Caa1 by Moody's Investors Service (Moody's) and B by Standard & Poor's (S&P). These downgrades are a result, at least in part, of the outlook for the consolidated business of El Paso Corporation and its need for liquidity. In the event that El Paso Corporation's liquidity needs are not satisfied, El Paso Corporation could be forced to seek protection from its creditors in bankruptcy.

We have publicly disclosed our efforts to further distinguish ourselves from El Paso Corporation. As a result of this announcement, various parties have expressed an interest in purchasing all or a portion of our general partner. El Paso Corporation has the sole responsibility for determining the ultimate ownership status of the general partner interest. We have publicly acknowledged that we are meeting with parties interested in acquiring an equity stake in the general partner but cannot confirm that such interest will result in firm proposals or, if such firm proposals are received, that El Paso Corporation will consider such proposals. If El Paso Corporation sells 50 percent or more of its interest in our general partner without obtaining consent from our lenders, we will experience a "change in control" under our credit agreements and indentures, which will effectively cause all amounts outstanding under those debt instruments to become due.

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

RELATED PARTY TRANSACTIONS

In our normal course of business we enter into transactions with various entities controlled directly or indirectly by El Paso Corporation. For the year ended December 31, 2002, $93 million of our related party revenue came from El Paso Merchant Energy North America Company (Merchant Energy), a direct subsidiary of El Paso Corporation. In November 2002, El Paso Corporation announced its intention to exit the energy trading business. Accordingly, we expect that we may have to replace our month-to-month, market priced sales of natural gas to Merchant Energy, which in 2002 represented revenue of approximately $60 million, with similar arrangements with third parties. In addition, Merchant Energy could sell or transfer to third parties the natural gas transportation and storage agreements they have with us, or Merchant Energy could request a cancellation of the transportation and storage agreements. In 2002, these agreements represented revenue of approximately $33 million. At present, Merchant Energy continues to fully utilize these agreements. As discussed above, one of our Independence Initiatives is to reduce our related party transactions in 2003. Revenues related to our sales of natural gas to Merchant Energy were $1.6 million in January 2003 and $1.2 million in February 2003, decreasing from $8.3 million in December 2002.

For the year ended December 31, 2002, $97 million of our related party revenue came from El Paso Field Services (Field Services), an indirect subsidiary of El Paso Corporation and a direct subsidiary of El Paso Tennessee Pipeline Co. This revenue stream is primarily related to our EPN Texas fractionation facilities, our Chaco plant and our Indian Basin plant. Field Services pays us a monthly fixed fee of $0.024 for each gallon of NGL that we fractionate into component parts at our EPN Texas fractionation facilities. Field Services receives the NGL we fractionate at our facilities from producers in south Texas. The fractionated NGL are re-delivered to Field Services at the tailgate of the plants and then sold by Field Services to various petrochemical and refining customers located along the Texas Gulf Coast. Prior to our acquisition of the San Juan assets, Field Services paid us a fee of $0.1344 per dekatherm of natural gas that we processed at the Chaco plant. With the November 2002 acquisition of the San Juan assets, we purchased, among other assets, the contracts Field Services had with the San Juan Basin producers and the related party nature of this processing revenue stream ended. During 2002, Field Services paid us market based rates for the NGL that we retained as a fee for processing services at our Indian Basin plant. Beginning in 2003, we are selling the NGL to third parties. Our revenues from Field Services were $4.6 million in January 2003 and $2.9 million in February 2003, decreasing from $9.1 million in December 2002.

In connection with our San Juan assets acquisition, we entered into a 10-year transportation agreement with El Paso Field Services. Beginning January 1, 2003, we will receive a fee of $1.5 million per year for transportation on our NGL pipeline acquired in the transaction which extends from Corpus Christi to near Houston. See Item 8, Financial Statements and Supplementary Data, Note 9 for a further discussion of our related party transactions.

LIQUIDITY AND CAPITAL RESOURCES

Our ability to execute our growth strategy and complete our current projects is dependent upon our access to the capital necessary to fund our projects and acquisitions. High profile business failures, allegations of corporate malfeasance, a slow economic recovery and increased unemployment among other factors have negatively affected the United States capital markets during 2002. Our business and industry have also experienced the adverse affects of the challenging economic climate during 2002, but we have succeeded in our capital raising efforts to fund many of our planned projects and acquisitions. Our continued success with capital raising efforts, including the formation of joint ventures to share costs and risks, will be the critical factor which determines how much we actually spend. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs and, although we currently intend to make the forecasted expenditures, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in the capital markets.

CAPITAL RESOURCES

Despite the widely known difficulties in the credit and equity markets, we successfully raised approximately $948 million in the fourth quarter of 2002 by (1) entering into our $160 million senior secured term loan; (2) issuing $200 million of 10 5/8% senior subordinated notes; (3) entering into our $237.5 million senior secured acquisition term loan and (4) issuing $350 million of our Series C units to a subsidiary of El Paso Corporation. We used the proceeds we received from the $160 million senior secured term loan to reduce amounts outstanding on our $600 million revolving credit facility. We used the net proceeds from our $200 million senior subordinated notes, our $237.5 million senior secured acquisition term loan and our $350 million Series C units we issued to a subsidiary of El Paso Corporation to purchase the San Juan assets from subsidiaries of El Paso Corporation. The continued strong operating performance of our existing assets has enabled us to increase our borrowing capacity under our financial covenants, effectively increasing our ability to access cash for executing our operating and growth objectives.

In February 2002, our shelf registration statement, as filed with the Securities and Exchange Commission, covering up to $1 billion of securities representing limited partnership interests, became effective.

In October 2002, we amended the terms of our $600 million revolving credit facility and the EPN Holding term credit facility in connection with our entering into the senior secured term loan. The modifications included, among other things, (1) entering into the $160 million senior secured term loan maturing in 2007 as a term component of our revolving credit facility, which we collectively refer to as our credit facility; (2) designating the EPN Holding term credit facility as "senior secured" indebtedness in addition to our credit facility, which is cross-collateralized on an equal basis with all of the collateral currently pledged under our credit facility and the EPN Holding term credit facility; (3) aligning, effectively, the covenants in our credit facility and the EPN Holding term credit facility, including eliminating the restrictions for distributing cash out of EPN Holding; and (4) terminating the $25 million revolving credit facility that was formerly part of the EPN Holding term credit facility.

In November 2002, we further amended our credit facility and the EPN Holding term credit facility in connection with our borrowing of $237.5 million under the senior secured acquisition term loan to modify the interest rates the facilities bear. The modified interest rate we are charged under the terms of the amendment will remain in effect until the senior secured acquisition term loan is repaid in full. Under the amended terms of these agreements, the loans bear interest at our option at either (i) 2.25% plus a variable base rate (equal to the greater of the prime rate as determined by JP Morgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JP Morgan Chase Bank plus 1.00%); or (ii) LIBOR plus 3.50%. The applicable rates on our revolving credit facility will revert to the historical rate schedule at LIBOR plus rates ranging from 0.875% to 2.50% or one of the variable base rates described above plus rates ranging from 0.0% to 1.50% following repayment of the $237.5 million senior secured acquisition term loan subject to our meeting certain ratios and attaining certain ratings as set forth in our credit facility. For the EPN Holding term credit facility, the applicable rates will revert to the historical rate schedule at LIBOR plus rates ranging from 1.75% to 2.50% or one of the variable base rates described above plus rates ranging from 0.50% to 1.25%, following repayment of the $237.5 million senior secured acquisition term loan, subject to our meeting certain ratios set forth in the EPN Holding term credit facility. The senior secured acquisition term loan was repaid in March 2003.

Our credit facility, EPN Holding term credit facility and senior secured acquisition term loan contain covenants that include restrictions on our and our subsidiaries' ability to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies and amend some of our contracts, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries and restrict our ability to make distributions to our unitholders. The financial covenants associated with these facilities are as follows:

(a) Consolidated tangible net worth cannot be less than $710.0 million plus 75 percent of the net proceeds we receive from the future sale or issuance of any equity securities by us;

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

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

(d) The ratio of our consolidated total indebtedness on the last day of any fiscal quarter through December 31, 2003 to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 5.25 to 1.0. The ratio of consolidated total indebtedness to consolidated EBITDA will decline to 5.0 to 1.0 beginning January 1, 2004.

Among other things, each credit agreement includes as an event of default the failure of El Paso Corporation and its subsidiaries to own more than 50 percent of our general partner unless our creditors agree otherwise. At

December 31, 2002, we are in compliance with the covenants of our credit agreements and indentures and we have available for use the entire $109 million remaining under our revolving credit facility.

We have features contained in our debt instruments described as ratings triggers. These triggers are contained in our:

- indentures governing our $200 million 10 5/8% Senior Subordinated Notes due 2012, our $230 million 8 1/2% Senior Subordinated Notes due 2011, our $250 million 8 1/2% Senior Subordinated Notes due 2011 and our $175 million 10 3/8% Senior Subordinated Notes due 2009, where many covenants will be suspended in the event we achieve an investment grade credit rating;

- $237.5 million senior secured acquisition term loan, where the interest rates we are charged will increase by 1.00% to 1.50% if our credit ratings decline below the higher of BB+ by S&P or Ba1 by Moody's. This loan was repaid in March 2003;

- $600 million credit facility, where we will receive a 0.38% to 0.50% reduction in interest rate if we achieve an investment grade credit rating; and

- $160 million senior secured term loan, if, at any time, our senior long-term unsecured debt rating issued by S&P is below BB+ and either our (a) senior, long-term unsecured debt rating issued by Moody's is below Ba2, or (b) our senior secured debt rating issued by Moody's is below Ba1, the interest rate on that term loan increases by 1.00%.

In August 2002, Deepwater Gateway, L.L.C., our joint venture that is constructing the Marco Polo TLP, obtained a $155 million project finance loan from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. Deepwater Gateway may elect that all or a portion of the project finance loan bear interest at either i) LIBOR plus 1.75% or ii) an alternate base rate (equal to the greater of the prime rate, the base CD rate plus 1% or the federal funds rate plus 0.5%, as those terms are defined in the project finance loan agreement) plus 0.75%. Deepwater Gateway must also pay commitment fees of 0.375% per year on the unused portion of the project finance loan. The loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the project finance loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2002, Deepwater Gateway has $27 million outstanding under the project finance loan at an average interest rate of 3.38% and had not paid us or any of our subsidiaries any distributions.

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

Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, is party to a $185 million credit agreement under which it has outstanding obligations that may restrict its ability to pay distributions to its owners. The interest rate Poseidon is charged on balances outstanding under its credit facility is dependent on its leverage ratio as defined in the Poseidon credit facility. Poseidon's interest rate at December 31, 2002 was LIBOR plus 1.50% for Eurodollar loans and a variable base rate equal to the greater of the Prime Rate or 0.50% plus the Federal Funds rate, (as those terms are defined in the Poseidon credit facility) plus 0.50% for base rate loans. In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of the $148 million outstanding under its credit facility at 3.49% through January 2004. Poseidon, under its credit facility, currently pays LIBOR plus 1.50%, resulting in an effective interest rate of 4.99% on the hedged notional amount. Poseidon's interest rate will decrease by 0.25% if their leverage ratio declines below 2.00 to 1.00 or by 0.50% if their leverage ratio declines to 1.00 to 1.00 or less. Additionally, Poseidon pays commitment fees on the unused portion of the credit facility at rates that vary from 0.25% to 0.375%.

This credit agreement requires Poseidon to maintain a debt service reserve equal to two quarters' interest and is collateralized by substantially all of Poseidon's assets. As of December 31, 2002, the remaining $73 million was at an average interest rate of 3.38%.

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

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

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

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

(c) the ratio of total indebtedness of Poseidon to EBITDA for the four quarters ending on the last day of the current quarter shall not exceed 3.00 to 1.00.

Poseidon was in compliance with the above covenants as of December 31, 2002.

SERIES B PREFERENCE UNITS

In August 2000, we issued 170,000 Series B preference units with a value of $170 million to acquire the Petal and Hattiesburg natural gas storage businesses from a subsidiary of El Paso Corporation. In October 2001, we redeemed 44,608 of the Series B preference units for a $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, 2002, the liquidation value of the outstanding Series B preference units was approximately $158 million. These 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.

SERIES C UNITS

In connection with our acquisition of the San Juan assets in November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of our Series C units, a new class of our limited partner interests, at a price of $32 per unit, $350 million in the aggregate. The Series C units are similar to our existing common units, except that the Series C units are non-voting limited partnership interests. After April 30, 2003, the holder of Series C units will have the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit will convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C unit will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate can increase on April 30, 2004 to 110 percent of the common unit distribution rate and on April 30, 2005 to 115 percent of the common unit distribution rate.

FORECASTED EXPENDITURES

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our operating and growth objectives. These estimates may change due to factors beyond our control, such as weather-related issues, changes in supplier prices or poor economic conditions. Further, estimates may change as a result of decisions made at a later date which may include scope changes or decisions to take on additional partners.

The table below depicts our estimate of expenditures on projects, acquisitions, operating lease payments and principal repayments of debt obligations for the year ending December 31, 2003 (in millions). These expenditures are net of anticipated project financings, contributions in aid of construction and contributions from joint venture partners including the anticipated formation of a joint venture with a 50 percent partner for the development of our Cameron Highway oil pipeline project, and project financing to fund a portion of the construction costs. Actual results may vary from these projections. We are contractually committed to the Cameron Highway project whether or not we obtain a partner or project financing.

	QUARTERS ENDING				NET TOTAL FORECASTED 2003 EXPENDITURES
	MARCH 31, 2003	JUNE 30, 2003	SEPTEMBER 30, 2003	DECEMBER 31, 2003	
NET FORECASTED CAPITAL PROJECT EXPENDITURES	$ 92	$66	$60	$41	$259
OTHER FORECASTED CAPITAL EXPENDITURES					
Capital expenditures for the Texas NGL assets	15	11	4	1	31
Maintenance capital	12	12	13	8	45
TOTAL OTHER FORECASTED CAPITAL EXPENDITURES	27	23	17	9	76
FORECASTED LEASE PAYMENTS AND DEBT OBLIGATION REPAYMENTS					
Senior secured term loan	--	2	--	3	5
Operating lease obligations	1	1	1	2	5
TOTAL FORECASTED LEASE PAYMENTS AND DEBT OBLIGATION REPAYMENTS	1	3	1	5	10
TOTAL FORECASTED EXPENDITURES	$120	$92	$78	$55	$345

DEBT REPAYMENT AND OTHER OBLIGATIONS

See Item 8, Financial Statements and Supplementary Data, Note 6, for a detailed discussion of our debt obligations.

The following table presents the timing and amounts of our debt repayment and other obligations for the years following December 31, 2002, that we believe could affect our liquidity (in millions):

DEBT REPAYMENT AND OTHER OBLIGATIONS	<1 YEAR	1-3 YEARS	3-5 YEARS	AFTER 5 YEARS	TOTAL
Revolving credit facility......................	$--	$491	$ --	$ --	$ 491
EPN Holding term credit facility................	--	160	--	--	160
Senior secured term loan.......................	5	10	145	--	160
Senior secured acquisition term loan...........	--	238	--	--	238
10 3/8% senior subordinated notes issued May 1999, due June 2009..........................	--	--	--	175	175
8 1/2% senior subordinated notes issued May 2001, due June 2011..........................	--	--	--	250	250
8 1/2% senior subordinated notes issued May 2002, due June 2011..........................	--	--	--	230	230
10 5/8% senior subordinated notes issued November 2002, due Dec 2012..................	--	--	--	200	200
Operating lease obligations....................	5	10	10	3	28
Total debt repayment and other obligations....	$10	$909	$155	$858	$1,932

We expect to renew our credit facility and raise additional capital during the next year through the issuance of additional common units and obtaining project financing for our Cameron Highway joint venture. We repaid our $238 million senior secured acquisition term loan in March 2003 with proceeds from an issuance of $300 million 8 1/2% Senior Subordinated Notes due 2010. We expect to use any capital we raise through the issuance of additional common units to reduce amounts outstanding under our credit facilities, to finance growth opportunities and for general partnership purposes. Our ability to raise additional capital may be negatively affected by many factors, including our relationship with El Paso Corporation.

CASH FROM OPERATING ACTIVITIES

Net cash provided by operating activities was $176.0 million for the year ended December 31, 2002, compared to $87.4 million for the same period in 2001. The increase was primarily attributable to operating cash flows generated by our acquisitions of the Chaco plant in October 2001, the remaining 50 percent interest in Deepwater Holdings that we did not already own in October 2001, the EPN Holding assets in April 2002 and the San Juan assets in November 2002. This increase was partially offset by lower cash distributions in 2002 from Poseidon, an unconsolidated affiliate.

CASH FROM INVESTING ACTIVITIES

Net cash used in investing activities was approximately $1.2 billion for the year ended December 31, 2002. Our investing activities include our November 2002 purchase of the San Juan assets, our April 2002 purchase of the EPN Holding assets, capital expenditures related to the expansion of our Petal natural gas storage facility and other asset purchases and capital projects. Further contributing to the expenditures were additions to investments in unconsolidated affiliates relating to our Marco Polo project. These expenditures were partially offset by proceeds from the April 2002 sale of our Prince TLP and nine percent Prince overriding royalty interest to El Paso Production Company and other asset sales. The Prince assets sales are reflected as net cash provided by investing activities of discontinued operations in our statement of cash flows.

CASH FROM FINANCING ACTIVITIES

Net cash provided by financing activities was approximately $1.1 billion for the year ended December 31, 2002. During 2002, our cash provided by financing activities included the issuances of long-term debt and common units, as well as borrowings under our credit facility, EPN Holding term credit facility, senior secured term loan and senior secured acquisition term loan. Cash used in our financing activities included repayments on our EPN Holding term credit facility, Argo term loan, our credit facility and other financing obligations, as well as distributions to our partners.

ACQUISITIONS AND CONSTRUCTION PROJECTS

ACQUISITIONS

San Juan Assets

In November 2002, we acquired the San Juan assets from subsidiaries of El Paso Corporation for $782 million, $766 million after adjustments for capital expenditures and working capital. The acquired assets include a natural gas gathering system located in the San Juan Basin of New Mexico, including El Paso Corporation's remaining interests in the Chaco cryogenic natural gas processing plant; NGL transportation and fractionation assets located in Texas; and an oil and natural gas gathering system located in the deeper water regions of the Gulf of Mexico. As part of this transaction, El Paso Corporation is required to repurchase the Chaco processing plant from us for $77 million in October 2021, and at that time, we will have the right to lease the plant from El Paso Corporation for a period of ten years with the option to renew the lease annually thereafter. With the close of this transaction, the monthly fee under our general and administrative services agreement with subsidiaries of El Paso Corporation increased by $1.3 million, bringing our total monthly fee to $2.9 million. The following is a description of the San Juan assets.

- The assets located in the San Juan Basin include:

  - approximately 5,300 miles of natural gas gathering pipelines, known as the San Juan gathering system, with capacity of over 1.1 Bcf/d connected to approximately 9,500 wells producing natural gas from the San Juan Basin located in northwest New Mexico and southwest Colorado;

  - approximately 250,000 horsepower of compression;

  - the 58 MMcf/d Rattlesnake CO_2 treating facility;

  - a 50 percent interest in Coyote Gas Treating, LLC, the owner of a 250 MMcf/d treating facility; and

  - the remaining interests in the Chaco cryogenic natural gas processing plant that we did not already own and the price risk management positions related to this facility's operations.

- The offshore pipeline assets include:

  - The Typhoon gas pipeline, a 35-mile, 20-inch natural gas pipeline originating on the Chevron/BHP "Typhoon" platform in the Green Canyon area of the Gulf of Mexico extending to the ANR Patterson System in Eugene Island Block 371; and

  - The Typhoon oil pipeline, a 16-mile, 12-inch oil pipeline originating on the Chevron/BHP "Typhoon" platform and extending to a platform in Green Canyon Block 19 with onshore access through various oil pipelines.

- The Texas NGL assets include:

  - a 163-mile, 4 to 6-inch propane pipeline extending from Corpus Christi to McAllen and the Hidalgo truck terminal facilities;

  - the Markham butane shuttle, a 124-mile, 8-inch pipeline with capacity of approximately 20 MBbls/d running between Corpus Christi and a leased storage facility at Markham with capacity of approximately 3.8 MMBbls;

- a 49-mile, 6-inch pipeline with capacity of approximately 15 MBbls/d extending from the Almeda fractionator to Texas City and the Texas City terminal;

- the Almeda fractionator, a 24 MBbls/d fractionator consisting of two trains, with both trains currently out of service, and related leased storage facilities of approximately 14.3 MMBbls; and

- a 201-mile, 8 to 10-inch pipeline with capacity of approximately 35 MBbls/d extending from Corpus Christi to the Almeda fractionator in Pasadena. This pipeline is currently out of service.

We are required to make approximately $49 million of capital expenditures to place the 201-mile 8 to 10-inch pipeline back in service and make repairs and upgrades on the Markham butane shuttle and the Almeda fractionator.

We financed our acquisition of the San Juan assets through long-term debt and equity as outlined below (in millions):

Series C units	$350
Senior secured acquisition term loan	238
Senior subordinated notes	194
Initial purchase price	782
Less working capital and capital expenditure adjustments	16
Net purchase price	$766

We issued 10,937,500 of our Series C units to El Paso Corporation for a value of $350 million.

The remaining balance of the purchase price was paid in cash. We funded this portion of the purchase price with net proceeds of $238 million from a senior secured acquisition term loan, which was repaid in March 2003 with our issuance of $300 million 8 1/2% Senior Subordinated Notes, and $194 million from our issuance of $200 million Senior Subordinated Notes, both of which are discussed in Item 8, Financial Statements and Supplementary Data, Note 6.

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

EPN Holding Assets

In April 2002, EPN Holding acquired from subsidiaries of El Paso Corporation midstream assets located in Texas and New Mexico, including one of the largest intrastate pipeline systems in Texas based on miles of pipe. The acquired assets include:

- the EPGT Texas intrastate pipeline system;

- the Waha natural gas gathering system and treating plant located in the Permian Basin region of Texas;

- the Carlsbad natural gas gathering system located in the Permian Basin region of New Mexico;

- an approximate 42.3 percent non-operating interest in the Indian Basin natural gas processing and treating facility located in southeastern New Mexico and the price risk management activities associated with the plant;

- a 50 percent undivided interest in the Channel natural gas pipeline system located along the Gulf coast of Texas;

- the TPC Offshore natural gas pipeline system located off the Gulf coast of Texas; and

- a leased interest in the Wilson natural gas storage facility located in Wharton County, Texas.

The $750 million sales price was adjusted for the assumption of $15 million of working capital related to natural gas imbalances. The net consideration of $735 million for the EPN Holding assets was comprised of the following (in millions):

Cash	$420
Assumed short term indebtedness payable to El Paso Corporation (none of which is outstanding as of December 31, 2002)	119
Common units	6
Sale of our Prince TLP and our nine percent Prince overriding royalty interest	190
	$735

To finance substantially all of the cash consideration related to this acquisition, EPN Holding entered into a $535 million term loan facility with a syndicate of commercial banks, of which $375 million has been repaid. The remaining amount was restructured in October 2002, as discussed in Item 8, Financial Statements and Supplementary Data, Note 6.

CONSTRUCTION PROJECTS

Medusa Project. We are constructing the $28 million, 37-mile Medusa natural gas pipeline extension of our Viosca Knoll gathering system with capacity to handle 160 MMcf/d of natural gas, which is expected to be in service in the third quarter of 2003. The pipeline is designed and located to gather production from Murphy Exploration and Production Company's Medusa development in the Gulf of Mexico. Murphy has dedicated 34,560 acres of property to this pipeline for the life of the reserves, which means that all natural gas produced from this acreage will flow through this pipeline. As of December 31, 2002, we have spent approximately $17.2 million related to this pipeline extension, which is currently under construction. We expect to receive contributions in aid of construction from Tennessee Gas Pipeline Company, a subsidiary of El Paso Corporation, of $2 million for benefits they expect to receive from our construction of the pipeline extension. We expect to fund the remaining project costs through internally generated funds and borrowings on our credit facility.

Marco Polo Project. In December 2001, we announced an agreement with Anadarko Petroleum Corporation under which we will construct, install and own the Marco Polo TLP with capacity to handle 120 MBbls/d of oil and 300 MMcf/d of natural gas. This TLP, which we expect to be in service in the fourth quarter of 2003, was designed and located to process oil and natural gas from Anadarko Petroleum Corporation's Marco Polo Field discovery in the Gulf of Mexico. Anadarko has dedicated 69,120 acres of property to this TLP, including the acreage underlying their Marco Polo Field discovery, for the life of the reserves. Anadarko will have firm capacity of 50 MBbls/d of oil and 150 MMcf/d of natural gas. The remainder of the platform capacity will be available to Anadarko for additional production and/or to third parties that have fields developed in the area. This TLP will be owned by Deepwater Gateway, L.L.C., our 50 percent owned joint venture with Cal Dive International, Inc., a leading energy services company specializing in subsea construction and well operations. We will operate Deepwater Gateway and the Marco Polo TLP will be operated by Anadarko. The total cost of the project is estimated to be $206 million, or approximately $103 million for our share. As of December 31, 2002, Deepwater Gateway has spent approximately $108.1 million on this TLP.

In August 2002, Deepwater Gateway obtained a $155 million project finance loan from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. The loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2002, Deepwater Gateway had $27 million outstanding under the project finance loan and had not paid us, our joint venture partner or any of our subsidiaries any distributions.

As of December 31, 2002, we have contributed $33 million, as our 50 percent share, to Deepwater Gateway, which amount satisfies our funding requirement related to the Marco Polo TLP. We expect that the remaining costs associated with the Marco Polo TLP will be funded through the $155 million project finance loan. This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. The loan agreement requires Deepwater Gateway to maintain a debt service reserve equal to six months' interest. Other than that debt service reserve and any other reserve amounts agreed upon by more than 66.7 percent majority interest of Deepwater Gateway's members, Deepwater Gateway will (after the project finance loan is either repaid or converted into a term loan) distribute any available cash to its members quarterly. Deepwater Gateway is not currently generating income or cash flow. Deepwater Gateway is managed by a management committee consisting of representative from each of its members.

In addition, we will construct and own a 36-mile, 14-inch oil pipeline and a 75-mile, 18 and 20-inch natural gas pipeline to support the Marco Polo TLP. The natural gas pipeline, with a maximum capacity of 400 MMcf/d, will gather natural gas from the Marco Polo platform in Green Canyon Block 608 and transport it to the Typhoon natural gas pipeline in Green Canyon Block 237. We intend to integrate the Marco Polo natural gas pipeline and the Typhoon natural gas pipeline. The oil pipeline will gather oil from the Marco Polo platform to our Allegheny pipeline in Green Canyon Block 164 with a maximum capacity of 120 MBbls/d. These pipelines are expected to be completed and placed in service in the first quarter of 2004, and are expected to cost a total of $96 million to construct. As of December 31, 2002, we have spent approximately $2.6 million on these pipelines, which are in the development stage. Additionally, we expect to receive contributions in aid of construction from ANR Pipeline Company and El Paso Field Services, subsidiaries of El Paso Corporation, totaling $17.5 million for benefits they anticipate receiving from our construction of the natural gas pipeline. As of December 2002, we received approximately $2 million from ANR as contributions in aid of construction of this pipeline. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

Cameron Highway. In February 2002, we announced that we will build and operate the $458 million, 390-mile Cameron Highway Oil Pipeline with capacity of 500 MBbls/d, which is expected to be in service by the third quarter of 2004 and will provide producers with access to onshore delivery points in Texas. BP p.l.c., BHP Billiton and Unocal have dedicated 86,400 acres of property to this pipeline for the life of the reserves, including the acreage underlying their ownership interests in the Holstein, Mad Dog and Atlantis developments in the deeper water regions of the Gulf of Mexico. In October 2002, we entered into a non-binding letter of intent with Valero Energy Corporation under which Valero would acquire a 50 percent interest in the entity we form to construct, install and own this pipeline, which we will operate. The formation of this joint venture is subject to specific conditions set forth in the letter of intent, including negotiating and executing definitive documentation and obtaining mutually acceptable financing. We are contractually committed to the Cameron Highway project whether or not we obtain a partner or any other financing. We expect that a majority of the costs of this project will be funded through project financing which we are currently negotiating. However, due to the volatility in the capital markets, it is conceivable that we could have to access capital from other sources, including cash from operations. We estimate that the majority of the capital outlay for the project will occur in 2003 and 2004. As of December 31, 2002, we have spent approximately $14.6 million related to this pipeline, which is in the development stage.

Phoenix (formerly known as Red Hawk). We announced that we will build and operate a new $63 million pipeline, now known as the Phoenix gathering system to gather natural gas production from the Red Hawk Field located in the Garden Banks area of the Gulf of Mexico. We have entered into related agreements with Kerr-McGee Oil and Gas Corporation, a wholly owned subsidiary of Kerr-McGee Corporation, and Ocean Energy, Inc., which each hold a 50 percent working interest in the Red Hawk Field. Kerr-McGee Oil and Gas Corporation and Ocean Energy, Inc. have dedicated multiple blocks at and in the proximity of the Red Hawk Field to this pipeline for the life of the reserves, subject to certain release provisions. The 76-mile pipeline, capable of transporting up to approximately 450 MMcf/d of natural gas, will originate in 5,300 feet of water at the Red Hawk Field and connect to the ANR Pipeline system at Vermillion

Block 397. We plan to place the new pipeline in service during the second quarter of 2004. As of December 31, 2002, we have spent approximately $0.1 million related to this pipeline, which is in the development stage. We expect to receive contributions in aid of construction from ANR Pipeline Company, a subsidiary of El Paso Corporation, of $6.1 million for benefits they expect to receive from our construction of this pipeline. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

COMPLETED PROJECTS

Petal Expansion. In June 2002, we completed a $68 million, 8.9 Bcf (6.3 Bcf working capacity) expansion of our Petal natural gas storage facility, including a withdrawal facility and a 20,000 horsepower compression station located near Hattiesburg, Mississippi. This brings the total working gas capacity of the Petal facility to 9.5 Bcf, of which 7 Bcf is dedicated to a subsidiary of The Southern Company, one of the largest producers of electricity in the United States, under a 20-year fixed-fee contract. In June 2002, we also completed a $100 million, 60-mile pipeline addition, including a 9,000 horsepower compression station, with capacity of 1.25 Bcf/d (currently FERC-certified to 700 MMcf/d) that interconnects with the storage facility and offers direct interconnects with the Southern Natural Gas, Transco and Destin pipeline systems. In June 2002, the interconnects with Southern Natural Gas and Destin were placed into service. In September 2002, the Transco interconnect was placed in service.

Falcon Nest. In April 2002, we entered into an agreement to construct and own the $53 million Falcon Nest fixed-leg platform, together with related pipelines, with capacity to handle 400 MMcf/d of natural gas. Falcon Nest will process natural gas from Pioneer Natural Resources Company's and Mariner Energy, Inc.'s Falcon Field discovery in the Gulf of Mexico. The platform and related pipelines were installed at Mustang Island Block 103 in the northwest portion of the Falcon Field and commissioned in the first quarter of 2003 and natural gas began flowing to the platform from the Falcon Field in March 2003. Pioneer and Mariner have dedicated 69,120 acres of property, including acreage underlying their Falcon Field discovery, to this platform for the life of the reserves. As of December 31, 2002, we have spent approximately $31.0 million on this project. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

OTHER MATTERS

As a result of current circumstances generally surrounding the energy sector, the creditworthiness of several industry participants has been called into question, including El Paso Corporation, the indirect parent of our general partner. As a result of these general circumstances, we have established an internal group to monitor our exposure to, and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties. If these general conditions worsen and, as a result, several industry participants file for Chapter 11 bankruptcy protection, it could have a material adverse effect on our financial position, results of operations or cash flows.

RESULTS OF OPERATIONS

Our business activities are segregated into four distinct operating segments:

- Natural gas pipelines and plants;

- Oil & NGL logistics;

- Natural gas storage; and

- Platform services.

In light of our expectation of acquiring additional natural gas pipeline and processing assets, effective January 1, 2002, we revised and renamed our business segments to reflect the change in composition of our operations. In October 2001, we acquired the Chaco plant and reflected the operations of this asset in our Oil and NGL logistics segment. With the change in our segments, we moved the Chaco processing plant to our Natural gas pipelines and plants segment. As a result of our sale of the Prince TLP and our nine percent overriding interest in the Prince Field in April 2002, the results of operations from these assets are reflected as discontinued operations in our statements of income for all periods presented and are not reflected in our segment results below. Beginning in 2002, operations from our oil and natural gas production activities are reflected in "Other."

To the extent possible, results of operations have been reclassified to conform to the current business segment presentation, although these results may not be indicative of the results which would have been achieved had the revised business segment structure been in effect during those periods. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. For a further discussion of the individual segments, see Item 8, Financial Statements and Supplementary Data, Note 14.

We use earnings before interest and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for several items, including: earnings from unconsolidated affiliates, minority interest of consolidated subsidiaries, gains and losses on sales of assets and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense, income tax benefit and discontinued operations. The following is a reconciliation of our operating results to EBIT and income from continuing operations for the years ended December 31:

NATURAL GAS NATURAL PIPELINES & OIL AND GAS PLATFORM PLANTS NGL LOGISTICS STORAGE SERVICES OTHER(1) TOTAL ----- ------ ------------- -------- ------- - -------- --------- FOR THE YEAR ENDED DECEMBER 31, 2002 Operating revenues from external customers............................ $ 357,581 $ 48,173 $ 28,602 $16,672 $ 16,890 $ 467,918 Operating intersegment revenues......... 227 -- -- 9,283 (9,510) -- Operating expenses..................... (236,240) (27,114) (20,476) (7,206) (15,599) (306,635) Operating income..................... 121,568 21,059 8,126 18,749 (8,219) 161,283 Earnings from unconsolidated affiliates........................... 194 13,445 -- -- -- 13,639 Net loss on sale of assets............. (473) -- -- -- -- (473) Minority interest in consolidated subsidiaries......................... 60 -- -- -- -- 60 Other income........................... 22 3 -- 114 1,398 1,537 --------- ------ -- -------- ------- -------- -------- - EBIT................................. $ 121,371 $ 34,507 $ 8,126 $18,863 $ (6,821) 176,046 ========= ======== ======== ======= ======== Interest and debt expense............... (83,494) --------- Income from continuing operations..... $ 92,552 ========= FOR THE YEAR ENDED DECEMBER 31, 2001 Operating revenues from external customers............................ $ 100,683 $ 32,327 $ 19,373 $15,385 $ 25,638 $ 193,406 Operating intersegment revenues......... 381 -- -- 12,620 (13,001) -- Operating expenses..................... (78,715) (12,092) (11,789) (7,251) (13,673) (123,520) --------- -------- -------- ------- -------- --------- Operating income..................... 22,349 20,235 7,584 20,754 (1,036) 69,886 Earnings (loss) from unconsolidated affiliates........................... (9,761) 18,210 -- -- -- 8,449 Net loss on sale of assets............. (7,309) -- -- (4,058) -- (11,367) Minority interest in consolidated subsidiaries......................... (51) -- -- -- (49) (100) Other income........................... 22,185 -- 20 3,426 3,095 28,726 --------- -------- -------- ------- -------- --------- EBIT................................. $ 27,413 $ 38,445 $ 7,604 $20,122 $ 2,010 95,594 ========= ======== ======== ======= ======== Interest and debt expense............... (41,542) --------- Income from continuing operations..... $ 54,052 ========= FOR THE YEAR ENDED DECEMBER 31, 2000 Operating revenues from external customers............................ $ 63,499 $ 8,307 $ 6,182 $13,875 $

20,552 $ 112,415 Operating intersegment revenues......... 629 -- -- 12,958 (13,587) -- Operating expenses..................... (37,945) (1,431) (3,992) (4,342) (22,654) (70,364) --------- -------- -------- ------- -------- --------- Operating income..................... 26,183 6,876 2,190 22,491 (15,689) 42,051 Earnings from unconsolidated affiliates........................... 10,213 12,718 -- -- -- 22,931 Minority interest in consolidated subsidiaries......................... (17) -- -- -- (78) (95) Other income........................... 608 1,728 3 -- 38 2,377 --------- -------- -------- ------- -------- --------- EBIT................................. $ 36,987 $ 21,322 $ 2,193 $22,491 $(15,729) 67,264 ========= ======== ======== ======= ======== Interest and debt expense............... (46,820) Income tax benefit..................... 305 --------- Income from continuing operations..... $ 20,749 =========

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(1) Represents predominately our oil and natural gas production activities as well as intersegment eliminations. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments.

We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our business and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures.

SEGMENT RESULTS

NATURAL GAS PIPELINES AND PLANTS

The Natural gas pipelines and plants segment includes the EPGT Texas intrastate pipeline system, the Viosca Knoll system, the HIOS system, the East Breaks system, the EPIA system, the Chaco cryogenic natural gas processing plant, the Indian Basin processing and treating facility, the San Juan natural gas gathering system and related assets, and the Typhoon natural gas pipeline. The natural gas gathering and transportation pipelines, which receive natural gas from producing properties in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and the Gulf of Mexico, primarily earn revenue from fixed-fee-based services or market-based rates that are usually related to the monthly natural gas price index for volume gathered. Offshore pipelines often involve life-of-reserve commitments with both firm and interruptible components, whereas onshore pipelines generally have contracts for a specific number of years or are month to month. The Chaco plant receives and processes natural gas from the San Juan Basin. The Indian Basin facility receives and processes natural gas from the Permian Basin. EPIA provides transportation services as well as marketing services through the purchase of natural gas from regional producers and others, and the sale of natural gas to local distribution companies and others. Beginning in 2001, we entered into fixed-for-floating commodity price swaps to hedge our commodity price exposure to EPIA's fixed price sales of natural gas, resulting in a fixed margin on the sales. These fixed price sales agreements represent less than two percent of EPIA's revenue or an average of 70 MDth/d. There was no significant impact on our realized cost of natural gas from these swaps for the year ended December 31, 2002. However, as a result of these swaps, our realized cost of natural gas may differ from the actual market prices of natural gas in future periods.

Starting in April 2002, in connection with our EPN Holding acquisition, we had swaps in place for our interest in the Indian Basin processing plant to hedge the price received for the sale of natural gas liquids. All of these hedges expired by December 31, 2002. We did not have any ineffectiveness in our hedging relationship since all sale prices are based on the same index and volumes as the hedged transactions. In connection with our acquisition of the San Juan assets in November 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 relating to gathering activities for changes in natural gas prices in the San Juan Basin. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transactions.

The following table presents EBIT derived from our Natural gas pipelines and plants segment and the related volumes associated with the indicated pipeline or plant (in thousands, except for volumes):

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Natural gas pipelines and plants revenues	$ 357,808	$101,064	$ 64,128
Cost of natural gas	(108,819)	(51,542)	(28,160)
Natural gas pipelines and plants margin	248,989	49,522	35,968
Other operating expenses	(127,421)	(27,173)	(9,785)
Other income (loss)	(197)	5,064	10,804
EBIT	$ 121,371	$ 27,413	$ 36,987
Volumes (Gross MDth/d)			
Texas Intrastate(1)	2,484	--	--
San Juan Gathering(2)	120	--	--
Permian gathering systems(1)	261	22	--
Viosca Knoll Gathering	565	551	612
HIOS	740	979	870
Other natural gas pipelines	399	416	232
Processing plants(2)	733	133	--
Gulf of Mexico assets sold	--	243	1,008
Total natural gas volumes	5,302	2,344	2,722

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(1) We purchased the Texas Intrastate assets, and the Carlsbad and Waha systems, which are included in the Permian gathering systems, in April 2002, as part of the EPN Holding acquisition.

(2) We purchased the San Juan gathering system, the remaining interest in the Chaco processing plant and the Typhoon natural gas pipeline in November 2002, as part of the San Juan assets acquisition.

In connection with our April 2002 EPN Holding acquisition, we added assets to this segment with contracts under which we purchase natural gas from producers at the wellhead for an index price less an amount that compensates us for gathering services. We then sell the natural gas into the open market at points on our system at the same index prices. Accordingly, our operating revenues and costs of natural gas are impacted by changes in energy commodity prices, while our margin is unaffected. For these reasons, we believe that gross margin (revenue less cost of natural gas) provides a more accurate and meaningful basis for analyzing operating results for the Natural gas pipelines and plants segment.

YEAR ENDED 2002 COMPARED TO YEAR ENDED 2001

Natural gas pipelines and plants margin for the year ended December 31, 2002, was $199.5 million higher than in 2001, primarily attributed to these asset acquisitions:

	(IN MILLIONS)
EPN Holding assets (April 2002)	$125.5
San Juan gathering and remaining Chaco interest (November 2002)	39.7
HIOS and East Breaks (October 2001, margin of $7.9 million in 2001)	28.0
Other (from June 2001 through August 2002, margin of $2.9 million in 2001)	7.4
Total	$200.6

The margin on the assets we owned for the full years in 2001 and 2002 decreased by $0.6 million in 2002 as a result of Hurricane Isidore in September 2002 and Hurricane Lili in October 2002, partially offset by additional volumes from production in the Camden Hills and Aconcagua Fields areas of the Gulf of Mexico, which are delivered to our Viosca Knoll system.

Other operating expenses for the year ended December 31, 2002 were $100.2 million higher than the same period in 2001 primarily due to our April 2002 purchase of the EPN Holding assets, our purchase of the

Chaco plant in October 2001, our consolidation of Deepwater Holdings and the purchase of the San Juan assets in November 2002. Excluding the operating costs of the newly acquired assets, other operating expenses increased by $2.3 million primarily due to an increase in EPIA's operating fee and an increase in gas imbalance cost on Viosca Knoll.

Other income for the year ended December 31, 2002, was $5.3 million lower than the same period in 2001 primarily due to our recognition in 2001 of $22.0 million in additional consideration from El Paso Corporation associated with the sale of our Gulf of Mexico pipeline assets in 2001, partially offset by net losses of $7.8 million due to the sale of our interests in the Tarpon and Green Canyon pipeline assets in January 2001. Also contributing to this decrease were lower earnings from unconsolidated affiliates of $9.8 million, which primarily relates to Deepwater Holdings' sale of Stingray, UTOS and the West Cameron dehydration facility and the sale of our interest in Nautilus and Manta Ray Offshore in 2001. Other loss for 2002 reflects additional losses associated with the sale of our Gulf of Mexico assets, offset by a gain on the sale of other assets and earnings from Coyote Gas Treating, LLC, an unconsolidated affiliate in which we acquired an interest in as part of the San Juan assets acquisition in November 2002.

YEAR ENDED 2001 COMPARED TO YEAR ENDED 2000

Natural gas pipelines and plants margin for the year ended December 31, 2001, was $13.5 million higher than in 2000. Approximately $17.4 million is due to our consolidation of Deepwater Holdings, our purchase of the Chaco plant in October 2001, our Indian Basin lateral, which went into service in June 2001, and an increase of $1.8 million due to higher volumes on EPIA as a result of a full twelve months of ownership in 2001 as well as larger spreads between natural gas sales prices and the cost to purchase natural gas in 2001. We acquired EPIA in March 2000. These increases were partially offset by a $3.2 million decrease due to lower volumes on the Viosca Knoll gathering system due to Tropical Storm Barry in August 2001 and a $3.0 million decrease due to the sale of the Tarpon and Green Canyon pipeline assets in January 2001.

Other operating expenses for the year ended December 31, 2001, were $17.4 million higher than in 2000, primarily due to our consolidation of Deepwater Holdings, our purchase of the Chaco plant in October 2001, and the abandonment and impairment of the Manta Ray pipeline in January 2001, which was partially offset by lower operating expenses resulting from our sales of assets in January 2001. We abandoned the Manta Ray pipeline as a result of our January 2001 sale of the Manta Ray Offshore system.

Other income for the year ended December 31, 2001, was $5.7 million lower than in 2000, primarily due to lower earnings from unconsolidated affiliates of $20.0 million, which primarily relates to Deepwater Holdings' sale of Stingray, UTOS, and the West Cameron dehydration facility and the sale of our interest in Nautilus and Manta Ray Offshore during the first six months of 2001 and the related losses on these sales. Also, we had a decrease in earnings from unconsolidated affiliates due to our consolidation of Deepwater Holdings in October 2001. Further contributing to the decrease in other income were net losses on sales of assets of $7.8 million due to the sales of our interests in the Tarpon and Green Canyon pipeline assets in January 2001 and a gain on the sale of other assets in 2000. These decreases were offset by $22 million of additional consideration from El Paso Corporation related to the sales of our Gulf of Mexico pipeline assets.

OIL AND NGL LOGISTICS

The Oil and NGL logistics segment includes the NGL transportation pipelines and fractionation plants of EPN Texas, the Poseidon, Allegheny and Typhoon offshore oil pipelines, the Almeda fractionator and other Texas NGL assets. The EPN Texas plants fractionate NGL into ethane, propane, butane and natural gasoline products which are used by refineries and petrochemical plants along the Texas Gulf Coast. We receive a fixed fee for each barrel of NGL transported and fractionated by the EPN Texas facilities from a subsidiary of El Paso Corporation. We have dedicated 100 percent of EPN Texas' fractionation facilities' capacity to this subsidiary of El Paso Corporation. The crude oil pipeline systems serve production activities in the Gulf of Mexico. Revenues from our oil pipelines are generated by production from reserves committed under long-term contracts for the productive life of the relevant field.

In connection with our San Juan assets acquisition in November 2002, we added the Typhoon Oil Pipeline to this segment. Typhoon Oil Pipeline's transportation agreement with two customers provides that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. Typhoon Oil reflects these sales in gathering and processing revenues and the related purchases as cost of oil. For these reasons, we believe that gross margin (revenue less cost of oil) provides a more accurate and meaningful basis for analyzing operating results for the Oil and NGL logistics segment.

The following table presents EBIT derived from our Oil and NGL logistics segment and the volumes associated with the indicated asset.

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Oil and NGL logistics revenues	$ 48,173	$ 32,327	$ 8,307
Cost of oil	(10,528)	--	--
Oil and NGL logistics margin	37,645	32,327	8,307
Other operating expenses	(16,586)	(12,092)	(1,431)
Other income	13,448	18,210	14,446
EBIT	$ 34,507	$ 38,445	$ 21,322
Liquid volumes (Bbl/d)			
EPN Texas	70,737	63,212	--
Allegheny Oil Pipeline	17,570	12,985	17,569
Typhoon Oil Pipeline(1)	1,211	--	--
Unconsolidated affiliate Poseidon Oil Pipeline(2)	135,652	155,453	157,436
Total liquid volumes	225,170	231,650	175,005

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(1) We purchased the Typhoon oil pipeline in November 2002, as part of the San Juan assets acquisition.

(2) Represents 100 percent of Poseidon volumes.

YEAR ENDED 2002 COMPARED TO YEAR ENDED 2001

Margin for the year ended December 31, 2002, was $5.3 million higher than the same period in 2001, primarily due to our acquisitions of the EPN Texas transportation and fractionation assets in February 2001, the Hattiesburg propane storage facility in January 2002, and the Anse La Butte NGL storage facility in December 2001. Additionally, in November 2002, we purchased Texas NGL facilities and an oil gathering system located in the deep water regions of the Gulf of Mexico, referred to as Typhoon Oil. Excluding assets purchased, our margin was $1.2 million higher primarily as a result of higher volumes on Allegheny.

Other operating expenses for the year ended December 31, 2002, were $4.5 million higher than the same period in 2001 primarily due to our acquisitions of the EPN Texas transportation and fractionation assets in February 2001, the Hattiesburg propane storage facility in January 2002, the Anse La Butte NGL storage facility in December 2001, the Typhoon Oil Pipeline and Texas NGL facilities in November 2002. Excluding assets purchased, our other operating expenses were $1.0 million lower as a result of modifying the operating agreement in connection with the EPN Holding acquisition in April 2002 between EPN Texas and El Paso Field Services.

Other income for the year ended December 31, 2002, was $4.8 million lower than the same period in 2001 primarily due to a decrease in earnings from unconsolidated affiliates due to lower volumes on Poseidon Oil Pipeline partially attributable to Hurricane Isidore in September 2002 and Hurricane Lili in October 2002. Offsetting this impact, were additional volumes related to new contracts entered into by Poseidon Oil Pipeline. These contracts started in November 2002 and December 2002 and have a six month duration. We will realize our 36 percent share of the volume increase through earnings from unconsolidated affiliates over the next four months.

YEAR ENDED 2001 COMPARED TO YEAR ENDED 2000

Revenues for the year ended December 31, 2001, were $24.0 million higher and other operating expenses were $10.7 million higher than in 2000, primarily due to the purchase of EPN Texas in February 2001. Excluding this acquisition, revenues were down $1.2 million due to decreased volumes on Allegheny as a result of platform shut-ins attributable to maintenance and tropical storm activity in late 2001.

Other income for the year ended December 31, 2001, was $3.8 million higher than in 2000, primarily due to an increase in earnings from unconsolidated affiliates of $5.5 million related to lower average interest rates on Poseidon's revolving credit facility in 2001 and lower earnings in 2000 resulting from Poseidon's pipeline rupture in January 2000. Partially offsetting this increase was the receipt of $1.7 million for business interruption insurance proceeds in 2000 related to the Poseidon pipeline rupture.

NATURAL GAS STORAGE

The Natural gas storage segment includes the Petal and Hattiesburg storage facilities, which were acquired in August 2000, and a leased interest in the Wilson natural gas storage facility, located in Wharton County, Texas, which we acquired in April 2002. The Petal and Hattiesburg storage facilities serve the Northeast, Mid-Atlantic and Southeast natural gas markets. In June 2002, we completed a 8.9 Bcf (6.3 Bcf working capacity) expansion of our Petal facility. As a result of the successful completion of this expansion and a general increase in the storage business, we have experienced interest from third parties in acquiring an ownership interest in our Petal and Hattiesburg facilities. We are evaluating all our options relating to these facilities, including discussions with various third parties to evaluate their level of interest. At this time, we cannot predict what changes, if any, in our ownership of these facilities will result from our evaluation.

For the years ended December 31, 2002, 2001 and 2000, the revenues from these facilities consist primarily of fixed reservation fees for natural gas storage capacity. Natural gas storage capacity revenues are recognized and due during the month in which capacity is reserved by the customer, regardless of the capacity actually used. We also receive fees for injections and withdrawals by our customers and interruptible storage fees. The following table presents EBIT derived from our Natural gas storage segment:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Natural gas storage revenue	$ 28,602	$ 19,373	$ 6,182
Operating expenses	(20,476)	(11,789)	(3,992)
Other income	--	20	3
EBIT	$ 8,126	$ 7,604	$ 2,193
Storage volumes			
Year end working gas capacity (Bcf)	13.5	7.5	7.5
Firm storage			
Average working gas capacity available (Bcf)	10.0	7.5	7.5
Average firm subscription (Bcf)	9.7	6.9	7.0
Commodity volumes(1) (Mdth/d)	127.0	63.0	19.0
Interruptible storage			
Contracted volumes (Bcf)	0.2	0.4	0.5
Commodity volumes(1) (Mdth/d)	32.0	52.0	--

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(1) Combined injections and withdrawals volumes.

YEAR ENDED 2002 COMPARED TO YEAR ENDED 2001

Natural gas storage revenue for the year ended December 31, 2002, was $9.2 million higher than the same period in 2001 primarily due to the expansion of the Petal storage facility and our acquisition of the Wilson storage facility lease in April 2002. Excluding the increase in margin from the Petal expansion and our acquisition of the Wilson storage facility lease, margin was down $2.3 million primarily as a result of a decrease in revenues attributable to interruptible storage services.

Operating expenses for the year ended December 31, 2002, were $8.7 million higher than the same period in 2001 primarily due to the expansion of our Petal storage facility in the second quarter of 2002, the acquisition of the Wilson storage facility lease in April 2002 and a favorable resolution of an imbalance settlement in 2001.

YEAR ENDED 2001 COMPARED TO YEAR ENDED 2000

The overall change in revenue and operating expenses is primarily the result of owning the Petal and Hattiesburg storage facilities for the full year of 2001. Fourth quarter 2001 revenues were $4.3 million compared to $4.6 million in 2000. This decrease was due to lower interruptible storage volumes in the fourth quarter of 2001. The overall change in operating expenses is primarily the result of owning the Petal and Hattiesburg storage facilities for the full year of 2001. Operating expenses for the fourth quarter of 2001 were not significantly changed from the fourth quarter of 2000.

We did not have any natural gas storage operations prior to August 2000.

PLATFORM SERVICES

The Platform services segment consists of the East Cameron 373, Viosca Knoll 817, Garden Banks 72, Ship Shoal 331, and Ship Shoal 332 platforms. These offshore platforms are used to interconnect our offshore pipeline grid, assist in performing pipeline maintenance, and conduct drilling operations during the initial development phase of an oil or natural gas property. Platform revenues are based on fixed and commodity charges. Fixed fees are recognized during the month reserved by the customer, regardless of how much capacity is actually used. Commodity fees are variable in nature and recognized when the service is provided. As part of our acquisition of the EPN Holding assets from subsidiaries of El Paso Corporation in April 2002, we sold the Prince TLP to a subsidiary of El Paso Corporation. The following table presents EBIT derived from our Platform services segment and volumes associated with each platform.

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Platform services revenue	$25,955	$28,005	$26,833
Operating expenses	(7,206)	(7,251)	(4,342)
Other income (loss)	114	(632)	--
EBIT	$18,863	$20,122	$22,491
Natural gas platform volumes (MDth/d)			
East Cameron 373	130	170	115
Viosca Knoll 817	8	12	3
Garden Banks 72	13	7	15
Total natural gas platform volumes	151	189	133
Oil platform volumes (Bbl/d)			
East Cameron 373	1,602	1,927	101
Viosca Knoll 817	2,064	2,049	1,982
Garden Banks 72	1,070	1,487	3,408
Total oil platform volumes	4,736	5,463	5,491

YEAR ENDED 2002 COMPARED TO YEAR ENDED 2001

Platform services revenue for the year ended December 31, 2002, was $2.1 million lower than in the same period in 2001 primarily due to the expiration in June 2002, in accordance with the original contract terms, of the fixed fee portion of the Viosca Knoll 817 platform access fee contract with Flextrend Development Company, our wholly owned subsidiary with production activities. The decrease was partially offset by one-time billing adjustments for fixed monthly platform access fees and a gas dehydration fee contract on the East Cameron 373 platform.

Other income for the year ended December 31, 2002, reflects income from an intersegment investment that is eliminated in our Other segment in consolidation. Other loss for the year ended December 31, 2001, included approximately $4.0 million of losses recognized on the sales of the Gulf of Mexico platform assets, partially offset by $3.4 million of additional consideration from El Paso Corporation related to the sale of these assets.

YEAR ENDED 2001 COMPARED TO YEAR ENDED 2000

Platform services revenue for the year ended December 31, 2001, was $1.2 million higher than in 2000, primarily due to increased volumes on East Cameron 373. The increase was partially offset by lower volumes on Garden Banks 72 due to a temporary shut-in of wells.

Operating expenses for the year ended December 31, 2001, were $2.9 million higher than in 2000, primarily due to the favorable resolution of litigation in June 2000.

Other loss for the year ended December 31, 2001, included approximately $4.0 million of losses recognized on the sales of the Gulf of Mexico platform assets, partially offset by $3.4 million of additional consideration from El Paso Corporation related to the sale of these assets.

OTHER

Our oil and natural gas production interests in the Garden Banks 72, Garden Banks 117 and Viosca Knoll 817 Blocks principally comprise the non-segment activity. Production from these properties is gathered, transported, and processed through our pipeline systems and platform facilities. Oil and natural gas production volumes are produced and sold to various third parties and subsidiaries of El Paso Corporation at the market price. Revenue is recognized in the period of production. These revenues may be impacted by market changes, hedging activities, and natural declines in production reserves. We are reducing our oil and natural gas production activities by not acquiring additional properties due to their higher risk profile, including risks associated with finding production and commodity prices. Accordingly, our focus is to maximize the production from our existing portfolio of oil and natural gas properties.

YEAR ENDED 2002 COMPARED TO YEAR ENDED 2001

EBIT related to non-segment activity for the year ended December 31, 2002, was $8.8 million lower than in the same period in 2001. The decrease was primarily due to lower natural gas and oil prices through most of 2002, as well as lower volumes attributable to a decrease in production as a result of normal decline of existing reserves. Further contributing to the decrease in income before interest and income taxes is decreased interest income on the additional consideration from El Paso Corporation related to the sale of the Gulf of Mexico assets as well as lower revenue due to Hurricane Isidore in September 2002 and Hurricane Lili in October 2002.

YEAR ENDED 2001 COMPARED TO YEAR ENDED 2000

EBIT related to non-segment activity for the year ended December 31, 2001 was $17.7 million higher than the same period in 2000. The increase was a result of higher realized natural gas prices, higher oil production volumes and lower depletion from natural gas production as a result of upward revisions of prior estimates of reserve quantities.

INTEREST AND DEBT EXPENSE

YEAR ENDED 2002 COMPARED TO YEAR ENDED 2001

Interest and debt expense on continuing operations, net of capitalized interest, for the year ended December 31, 2002, was approximately $42.0 million higher than the same period in 2001. This increase is primarily due to an increase in the average outstanding balance of our revolving credit facility, the amounts outstanding under the EPN Holding term credit facility which we entered to purchase the EPN Holding assets in April 2002, and the $230 million 8 1/2% senior subordinated notes issued in May 2002. Additionally, interest expense increased by approximately $5.2 million as a result of additional indebtedness we incurred in the fourth quarter of 2002 (see Item 8, Financial Statements and Supplementary Data, Note 6) in connection with our San Juan assets acquisition including additional interest expense associated with amending our credit facility and the EPN Holding term credit facility. Capitalized interest for the year ended December 31, 2002 was $5.6 million compared to $11.8 million for the same period in 2001.

We expect our interest and debt expense to increase in 2003 by approximately $43.2 million due to the additional debt we incurred during the fourth quarter of 2002, and the change in interest rates resulting from amending our credit facility and the EPN Holding term credit facility. We computed the expected increase employing the weighted average interest rates in effect and balances outstanding at December 31, 2002.

YEAR ENDED 2001 COMPARED TO YEAR ENDED 2000

Interest and debt expense, net of capitalized interest, for the year ended December 31, 2001, was approximately $5.3 million lower than 2000. This decrease primarily relates to an increase in capitalized interest of approximately $4.1 million due to an increase in our construction activity in 2001, as well as lower average interest rates in 2001. The overall decrease in interest expense was partially offset by the issuance of $250 million of 8 1/2% Senior Subordinated Notes in May 2001.

COMMITMENTS AND CONTINGENCIES

See Item 8, Financial Statements and Supplementary Data, Note 10, for a discussion of our commitments and contingencies.

CRITICAL ACCOUNTING POLICIES

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by analyzing similar situations and the accounting guidance governing them, and often consult with our independent accountants about the appropriate interpretation and application of these policies. In addition, the preparation of our financial statements in conformity with accounting policies 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. Our critical accounting policies are discussed below. Each of these areas involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

Reserves for Contingencies

We accrue reserves for contingent liabilities including, but not limited to, environmental remediation and clean-up costs, and potential legal claims, when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our estimates for these liabilities are based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Our actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon the outcome or expectations based on the facts surrounding each exposure.

We currently have a reserve for environmental matters; however, we have no reserves for non-environmental legal matters. New environmental developments, such as increasingly strict environmental laws and regulations and new claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial cost and future liabilities. Also, new legal matters, adverse rulings or anticipated adverse rulings on pending legal matters, or proposed settlements on pending legal matters could result in substantial cost or future liabilities.

Asset Impairment

The asset impairment accounting rules require us to determine if an event has occurred indicating that a long-lived asset may be impaired. In certain cases, a clearly identifiable triggering event does not occur, but rather a series of individually insignificant events over a period of time leads to an indication that an asset may be impaired. We continually monitor our businesses and the market and business environments and make our judgments and assessments concerning whether a triggering event has occurred. If an event occurs, we must make an estimate of our future cash flows from these assets to determine if the asset is impaired. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal, regulatory and other factors. Changes in the economic and business environment in the future, such as production declines that are not replaced by new discoveries, long term decreases in the demand or price of oil and natural gas, may lead to an indication that an impairment may have occurred.

Depreciation of Property, Plant and Equipment

We estimate our depreciation based on an estimated useful life and residual salvage values. Estimated dismantlement, restoration and abandonment costs are taken into account in determining depreciation provisions for gathering pipelines, platforms, related facilities and oil and natural gas properties. At the time we place our assets into service, we believe our estimates are accurate. However, circumstances in the future may develop which would cause us to change these estimates and in turn would change our depreciation amounts on a going forward basis. Some of these circumstances include changes in laws and regulations relating to restoration and abandonment requirements; changes in the expected costs for dismantlement, restoration and abandonment as a result of changes, or expected changes, in labor, materials and other related costs associated with these activities; changes in the useful life of an asset based on the actual known life of similar assets, changes in technology, or other factors; and changes in expected salvage proceeds as a result of a change, or expected change, in the salvage market.

Oil and Natural Gas Reserves and Amortization of Oil and Natural Gas Properties

The process of estimating quantities of natural gas and crude oil reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures. We use the units-of-production method to amortize capitalized costs of our oil and natural gas properties. Changes in reserve quantities as described above will cause corresponding changes in depletion expense in periods subsequent to the quantity revision.

Volume Measurement

We record amounts for natural gas gathering and transportation revenue, liquid transportation and handling revenue, natural gas and oil sales and related natural gas and oil purchases, and the sale of production based on volumetric calculations. Variances resulting from such calculations are inherent in our business.

Revenue and Cost of Natural Gas, Oil and Other Products Estimates

Each month we record an estimate for our operating revenues and cost of natural gas, oil and other products along with a true-up of the prior month's estimate to equal prior month's actual data. Accordingly, there is one month of estimate data recorded in our operating revenues and cost of natural gas, oil and other products accounts for the years ended December 31, 2002, 2001 and 2000. The estimates are based on actual volume and price data through the first part of the month then extrapolated to the end of the month, adjusted accordingly for any known or expected changes in volumes or rates through the end of the month.

Price Risk Management Activities

We account for price risk management activities based upon the fair value accounting methods prescribed by SFAS No. 133 which prescribes our accounting for hedging activities and other derivatives. This accounting rule requires that we determine the fair value of the financial instruments we use in these business activities and reflect them in our balance sheet at their fair values. The changes in the fair value from period to period of cash flow hedges are reported in Other Comprehensive Income (OCI). The gains and losses from the changes in fair value of derivative instruments that are reported in OCI are reclassified to earnings in the periods in which earnings are impacted by the hedged items.

One of the primary factors that can have an impact on our results each period is the price assumptions used to value our cash flow hedges. We use published market price information where available, or quotations from traders in the market to find executable bids and offers. If the fair value of our hedges cannot be determined from readily available market-based information, we use internal valuation techniques or models to estimate the fair value of such instruments. Such modeling techniques generally are only required to extrapolate the prices of the NGL (for which market-based prices are not readily available beyond three to six months) based on historical pricing relationships between natural gas, crude oil and the NGL components. Our estimates also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

At inception and on an ongoing basis, we conduct correlation analysis between the price of the exposure we are hedging, and the hedging instrument. We use hedge accounting where we conclude that the derivative that we will enter into will be highly effective in offsetting the price volatility of the item being hedged. If a financial instrument we have entered into is no longer effective in offsetting price volatility, it can no longer be designated as a cash flow hedge and changes in the fair value would be reported directly in the income statement.

Gas Imbalances

We record imbalance receivables and payables when a customer delivers more or less gas into our pipelines than they take out. We primarily estimate the value of our imbalances at prices representing the estimated value of the imbalances upon settlement. Changes in natural gas prices may impact our valuation. We do not value our imbalances based on current month prices because it is not likely that we would purchase or receive natural gas at that point in time to settle the imbalance.

NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

We continually monitor and revise our accounting policies as developments occur. At this time, there are several new accounting pronouncements that have recently been issued, but are not yet adopted, which will impact our accounting when these rules become effective in the future. Some of these new rules may have an impact on our critical accounting policies.

For further details on our accounting policies, and the estimates, assumptions and judgments we use in applying these policies and a discussion of new accounting rules, see Item 8, Financial Statements and Supplementary Data, Note 1.

RISK FACTORS AND CAUTIONARY STATEMENT

This report contains or incorporates by reference forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and made in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, such expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe", "expect", "estimate", "anticipate" and similar expressions may identify forward-looking statements. All of our forward-looking statements, whether written or oral, are expressly qualified by these ordinary cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

With this in mind, you should consider the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

RISKS RELATED TO OUR BUSINESS

OUR INDEBTEDNESS COULD ADVERSELY RESTRICT OUR ABILITY TO OPERATE, AFFECT OUR FINANCIAL CONDITION AND PREVENT US FROM FULFILLING OUR OBLIGATIONS UNDER OUR DEBT SECURITIES.

We have a significant amount of indebtedness and the ability to incur substantially more indebtedness. As of December 31, 2002, we had approximately $1.0 billion outstanding under four senior secured credit facilities and $858 million outstanding under indentures related to our senior subordinated notes. After our March 2003 issuance of senior subordinated notes, we had approximately $1.2 billion outstanding under indentures related to our senior subordinated notes.

From time to time, our joint ventures also incur indebtedness. As of December 31, 2002, Poseidon Oil Pipeline Company, L.L.C., in which we own a 36 percent interest, had $148 million outstanding under its revolving credit facility and Deepwater Gateway, L.L.C., in which we own a 50 percent interest, had $27 million outstanding under its project finance loan. If Deepwater Gateway 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 Deepwater Gateway up to $22.5 million. Our obligation to make such a payment is collateralized by substantially all of our assets on the same basis as our obligations under our credit facility, our senior secured acquisition term loan and the EPN Holding term credit facility.

We and all of our subsidiaries, except for our unrestricted subsidiaries, must comply with various affirmative and negative covenants contained in the indentures related to our senior subordinated notes, and our credit facilities. Among other things, these covenants limit the ability of us and our subsidiaries, except for our unrestricted subsidiaries, to:

- incur additional indebtedness or liens;

- make payments in respect of or redeem or acquire any debt or equity issued by us;

- sell assets;

- make loans or investments;

- acquire or be acquired by other companies; and

- amend some of our contracts.

We do not have the right to prepay the balance outstanding under our senior subordinated notes without incurring substantial economic penalties. Additionally, we are required to use the net proceeds of any securities offerings we complete to repay our senior secured acquisition term loan. The restrictions under our indebtedness may prevent us from engaging in certain transactions which might otherwise be considered beneficial to us and could have other important consequences to you. For example, they could:

- increase our vulnerability to general adverse economic and industry conditions;

- limit our ability to make distributions to unitholders, including our minimum quarterly distribution amounts, to fund future working capital, capital expenditures and other general partnership requirements; to engage in future acquisitions, construction or development activities; or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness;

- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate; and

- place us at a competitive disadvantage as compared to our competitors that have less debt.

We may incur additional indebtedness (public or private) in the future, either under our existing credit facilities, by issuing debt securities, under new credit agreements, under joint venture credit agreements, under capital leases or synthetic leases, on a project finance or other basis, or a combination of any of these. If we incur additional indebtedness in the future, it would be under our existing credit facility or under arrangements which may have terms and conditions at least as restrictive as those contained in our existing credit facilities and existing indentures. Failure to comply with the terms and conditions of any existing or future indebtedness would constitute an event of default. If an event of default occurs, the lenders will have the right to accelerate the maturity of such indebtedness and foreclose upon the collateral, if any, securing that indebtedness. If an event of default occurs under our joint ventures' credit facilities, we may be required to repay amounts previously distributed to us and our subsidiaries. In addition, if El Paso Corporation and its subsidiaries no longer own more than 50 percent of our general partner, that will (1) be an event of default, unless our creditors agreed otherwise, under our credit facilities and (2) require us to offer to repurchase all of our senior subordinated notes at 101 percent of their par value. Any such event could limit our ability to fulfill our obligations under our debt securities and to make cash distributions to unitholders, including our minimum quarterly distribution amounts, which could adversely affect the market price of our securities.

WE MAY NOT BE ABLE TO FULLY EXECUTE OUR GROWTH STRATEGY IF WE ENCOUNTER TIGHT CAPITAL MARKETS OR INCREASED COMPETITION FOR QUALIFIED ASSETS.

Our strategy contemplates substantial growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively, diversify our asset portfolio and, thereby, provide more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, additional potential joint ventures, stand-alone projects and other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business, increase our market position and, ultimately, increase distributions to unitholders.

We will need new capital to finance the future development and acquisition of assets and businesses. Limitations on our access to capital will impair our ability to execute this strategy. Expensive capital will limit our ability to develop or acquire accretive assets. Although we intend to continue to expand our business, this strategy may require substantial capital, and we may not be able to raise the necessary funds on satisfactory terms, if at all. For example, if our common unitholders do not approve the conversion of our outstanding Series C units into common units when requested and, accordingly our Series C units receive a preferential distribution rate, issuance of common units will become a more expensive method of raising capital for us in the future.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in our not being the successful bidder more often or our acquiring assets at a higher relative price than we have paid historically. Either occurrence would limit our ability to fully execute our growth strategy. Our ability to execute our growth strategy may impact the market price of our securities.

OUR GROWTH STRATEGY MAY ADVERSELY AFFECT OUR RESULTS OF OPERATIONS IF WE DO NOT SUCCESSFULLY INTEGRATE THE BUSINESSES THAT WE ACQUIRE OR IF WE SUBSTANTIALLY INCREASE OUR INDEBTEDNESS AND CONTINGENT LIABILITIES TO MAKE ACQUISITIONS.

We may be unable to integrate successfully businesses we acquire. We may incur substantial expenses, delays or other problems in connection with our growth strategy that could negatively impact our results of operations. Moreover, acquisitions and business expansions involve numerous risks, including:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;

- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including unfamiliarity with their markets; and

- diversion of the attention of management and other personnel from day-to-day business, the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, depletion and amortization expenses. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect upon our business, as discussed above.

OUR ACTUAL CONSTRUCTION, DEVELOPMENT AND ACQUISITION COSTS COULD EXCEED OUR FORECAST, AND OUR CASH FLOW FROM CONSTRUCTION AND DEVELOPMENT PROJECTS MAY NOT BE IMMEDIATE.

Our forecast contemplates significant expenditures for the development, construction or other acquisition of energy infrastructure assets, including some construction and development projects with significant technological challenges. For example, underwater operations, especially those in water depths in excess of 600 feet, are very expensive and involve much more uncertainty and risk and if a problem occurs, the solution, if one exists, may be very expensive and time consuming. Accordingly, there is an increase in the frequency and amount of cost overruns related to underwater operations, especially in depths in excess of 600 feet. We may not be able to complete our projects, whether in deep water or otherwise, at the costs currently estimated. If we experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;

- delaying other planned projects;

- incurring additional indebtedness; or

- issuing additional debt or equity.

Any or all of these methods may not be available when needed or may adversely affect our future results of operations.

Our revenues and cash flow may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline or platform or expand an existing facility, the design, construction, development and installation may occur over an extended period of time and we may not receive any material increase in revenue or cash flow from that project until after it is placed in service and customers enter into binding arrangements. If our revenues and cash flow do not increase at projected levels because of substantial unanticipated delays, we may not meet our obligations as they become due and we may have to reduce or eliminate distributions to unitholders.

THE FUTURE PERFORMANCE OF OUR ENERGY INFRASTRUCTURE OPERATIONS, AND THUS OUR ABILITY TO SATISFY OUR DEBT REQUIREMENTS AND MAINTAIN CASH DISTRIBUTIONS, DEPENDS ON SUCCESSFUL EXPLORATION AND DEVELOPMENT OF ADDITIONAL OIL AND NATURAL GAS RESERVES BY OTHERS.

The oil, natural gas and other products available to our energy infrastructure assets are derived from reserves produced from existing wells, which reserves naturally decline over time. In order to offset this natural decline, our energy infrastructure assets must access additional reserves. Additionally, some of the projects we have planned or recently completed, including our Falcon Nest platform, our Deepwater Gateway joint venture and our Cameron Highway project, are dependent on reserves that we expect to be produced from newly discovered properties that producers are currently developing.

Finding and developing new oil and natural gas reserves is very expensive, especially offshore. The flextrend (water depths of 600 to 1,500 feet) and deepwater (water depths greater than 1,500 feet) areas of the Gulf of Mexico in particular will require large capital expenditures by producers for exploration and development drilling, installing production facilities and constructing pipeline extensions to reach the new wells. Many economic and business factors out of our control can adversely affect the decision by any producer to explore for and develop new reserves. These factors include relatively low oil and natural gas prices, cost and availability of equipment, regulatory changes, capital budget limitations or the lack of available capital. Additional reserves, if discovered, may not be developed in the near future or at all. For example, because of the level to which hydrocarbon prices declined during 1998 and the first quarter of 1999, overall oil and natural gas activity declined in relation to prior years. If hydrocarbon prices decline to those levels again or if capital spending by the energy industry decreases or remains at low levels for prolonged periods, our results of operations and cash flow could suffer.

WE WILL BE ADVERSELY AFFECTED IF WE CANNOT NEGOTIATE AN EXTENSION OR REPLACEMENT ON COMMERCIALLY REASONABLE TERMS OF THREE MATERIAL CONTRACTS WHICH ACCOUNT FOR APPROXIMATELY 70 PERCENT OF THE VOLUME ATTRIBUTABLE TO THE SAN JUAN GATHERING SYSTEM DURING 2002 AND WHICH EXPIRE BETWEEN 2006 AND 2008.

For the year ended December 31, 2002, approximately 70 percent of the volume attributable to the San Juan gathering system is derived from contracts with three major customers, Burlington Resources, Conoco and BP. These contracts expire in 2008, 2006 and 2006. If we are not able to successfully negotiate replacement contracts, or if the replacement contracts are on less favorable terms, the effect on us will be adverse. The following table indicates the percentage revenue generated by each contract in relation to the indicated denominator for the year ended December 31, 2002:

BASE REVENUE	BURLINGTON RESOURCES	CONOCO	BP	TOTAL
San Juan gathering revenue(1)...........	30.6%	20.9%	14.5%	66.0%
Total revenue of El Paso Energy Partners, L.P. (1).....................	6.9%	4.7%	3.3%	14.9%

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(1) We have assumed twelve months of San Juan revenues in our calculation of the percentage revenue generated by each customer in order to more accurately reflect annual results. The revenue reflected in our statement of income only includes San Juan as of the acquisition date.

WE WILL BE ADVERSELY AFFECTED IF WE CANNOT NEGOTIATE AN EXTENSION OR A REPLACEMENT ON COMMERCIALLY REASONABLE TERMS OF APPROXIMATELY 900 MILES OF RIGHTS-OF-WAY UNDERLYING THE SAN JUAN GATHERING SYSTEM.

Approximately 900 miles of the San Juan gathering system benefits from rights-of-way granted over Native American lands. These rights-of-way expire in 2005. Although these rights-of-way have been renewed in the past, these rights-of-way may not continue to be renewed on commercially reasonable terms, or on any terms. If these rights-of-way are not renewed or if the fees for these rights-of-way increase substantially, the effect on us will be adverse.

FLUCTUATIONS IN INTEREST RATES COULD ADVERSELY AFFECT OUR BUSINESS.

In addition to our exposure to commodity prices, we also have exposure to movements in interest rates. The interest rates on some of our indebtedness, like our senior subordinated notes, are fixed and the interest rates on some of our other indebtedness, like our credit facility and senior secured acquisition term loan, EPN Holding term credit facility and the credit facilities of our joint ventures, are variable. Our results of operations and our cash flow, as well as our access to future capital and our ability to fund our growth strategy, could be adversely affected by significant increases or decreases in interest rates.

OUR EPN TEXAS FRACTIONATION FACILITIES ARE DEDICATED TO A SINGLE CUSTOMER, THE LOSS OF WHICH COULD ADVERSELY AFFECT US.

In connection with our acquisition of our EPN Texas fractionation facilities, we entered into a 20-year fee-based transportation and fractionation agreement and have dedicated 100 percent of the capacity of our fractionation facilities to a subsidiary of El Paso Corporation. In that agreement, all of the NGL derived from processing operations at seven natural gas processing plants in south Texas owned by subsidiaries of El Paso Corporation are delivered to our NGL transportation and fractionation facilities. Effectively, we will 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. El Paso Corporation's subsidiary will bear substantially all of the risks and rewards associated with changes in the commodity prices for NGL produced at the EPN Texas fractionation facilities.

Our operations are likely to be adversely affected if this arrangement is terminated or if El Paso Field Services does not deliver enough NGL to us to ensure that we can maintain a profitable utilization rate or does not fully perform its obligations under the agreement.

FLUCTUATIONS IN ENERGY COMMODITY PRICES COULD ADVERSELY AFFECT OUR BUSINESS.

Oil, natural gas and other petroleum products prices are volatile and could have an adverse effect on a portion of our revenues and cash flow. Although our strategy involves mitigating our exposure to the volatility in commodity prices, primarily by focusing on fee-based services, all segments of our operations are somewhat affected by price reductions and some of our segments are significantly affected by price reductions. Price reductions can materially reduce the level of oil and natural gas exploration, pipeline volumes, production and development operations, which provide reserves to replace those that are produced over time. In addition, some of our operations, like production, processing and fractionation, are very sensitive to price declines.

Natural gas pipelines and plants -- Price decreases could have an adverse effect on the discovery and development of replacement reserves and on the results of operations of our San Juan natural gas gathering system, our Chaco plant and our Indian Basin plant.

Currently, the primary consequence of commodity price reductions to our pipeline and platform operations is the risk that less replacement reserves will be discovered and developed as a result of a long-term decline in prices. Although the majority of our pipeline and platform operations involve fee-based arrangements for gathering, transporting and handling reserves that are dedicated to the facilities for the life of the reserves, some of our pipelines can be dramatically affected by a reduction in commodity prices because those pipelines purchase and resell the commodity.

The financial results from our San Juan natural gas gathering system, our Chaco plant and our Indian Basin plant can be dramatically affected by a reduction in, or the volatility of, commodity prices. For example, over 95 percent of the volumes handled by the San Juan gathering system are fee-based arrangements, 80 percent of which are calculated as a percentage of a regional natural gas price index. In addition, the San Juan gathering system provides aggregating and bundling services -- in which it purchases gas at the wellhead and resells gas in the open market -- for some smaller producers, which account for less than five percent of the volumes on that system.

Prices for natural gas, NGL and NGL components can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Contemporaneously with the November 2002 San Juan assets acquisition, our tolling arrangement with a subsidiary of El Paso Corporation relating to the Chaco plant was terminated. Accordingly, a substantial portion of our Chaco plant processing arrangements are now exposed to commodity price risk -- specifically prices for NGL. Substantially all of our revenues for natural gas processing services at the Chaco plant and Indian Basin plant will fluctuate directly with the monthly price of NGL.

Utilization rates in the processing industry can fluctuate dramatically from month to month, depending on the needs of producers. The average utilization rate for the Chaco processing plant for the calendar years 2002, 2001, and 2000 was 90 percent, 89 percent and 91 percent. The average utilization rate for the Indian Basin processing plant for the calendar years 2002, 2001 and 2000 was 93 percent, 93 percent and 82 percent.

Natural gas storage -- Natural gas price stability could have an adverse effect on revenue and cash flow from our storage assets.

Prices for natural gas have historically been seasonal and volatile, which has enhanced demand for our storage services. The storage business has benefited from large price swings resulting from seasonal price sensitivity through increased withdrawal charges and demand for non-storage hub services. However, the market for natural gas may not continue to experience volatility and seasonal price sensitivity in the future at the levels previously seen. If volatility and seasonality in the natural gas industry decrease, because of increased storage capacity throughout the pipeline grid, increased production capacity or otherwise, the demand for our storage services and, therefore, the prices that we will be able to charge for those services may decline.

Oil and NGL logistics -- The fractionation business is cyclical and is dependent in part upon the spreads between prices for natural gas, NGL and petroleum products.

Since our fractionation facilities provide fee-based services, for which we receive a fixed fee for each unit of NGL we fractionate, our fractionation operations are not directly affected by fluctuations in prices for natural gas, NGL and NGL components. However, if the spread between prices for natural gas, NGL and NGL components do not provide sufficient profits to natural gas producers, then those producers may decide not to process their natural gas or fractionate their NGL, or to process less natural gas or fractionate less NGL. This could decrease the volumes to our processing and fractionation facilities and, accordingly, negatively affect our operational results. In many cases, processing and fractionating is profitable only when the producer can receive more net proceeds by physically separating the natural gas from the NGL and separating the NGL components from the NGL and selling those products than it would receive by merely selling the raw natural gas stream. The spread between the prices for natural gas and NGL is greatest when the demand for NGL increases for use in petrochemical and refinery feedstock. If, and when, this spread becomes too narrow to justify the costs, producers have the option to sell the raw natural gas stream rather than process and fractionate. In such a case, our processing or fractionation facilities or both will be underutilized. Although our fixed fee-based arrangements limit the direct effects of decreases in commodity prices on our fractionation operations, those arrangements also cause us to forego any benefits we would otherwise experience if commodity prices were to increase.

Utilization rates in the fractionation industry can fluctuate dramatically from month to month, depending on the needs of producers. The monthly utilization rate for our fractionation facilities during the 12 months ending December 31, 2002 was as low as 58 percent and as high as 82 percent. However, our average annual utilization rate for our fractionation facilities for 2002, 2001 and 2000 were 74 percent, 73 percent and 89 percent.

Oil and natural gas production -- Price and volume volatility is substantially out of our control and could have an adverse effect on revenues and cash flow from our producing oil and natural gas properties.

We have exposure to movements in commodity prices relating to our oil and natural gas production, which we partially hedge from time to time using financial derivative instruments. Our results of operations and our cash flow could be materially adversely affected by factors we cannot control, including:

- fluctuations in prices of oil and natural gas;

- future operating costs; and

- risks incident to the operation of oil and natural gas wells.

ENVIRONMENTAL COSTS AND LIABILITIES AND CHANGING ENVIRONMENTAL REGULATION COULD AFFECT OUR CASH FLOW.

Our operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including fines, injunctions or both. Third parties may also have the right to pursue legal actions to enforce compliance. We will make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations, including the handling, manufacture, use, emission or disposal of substances and wastes. Moreover, as with other companies engaged in similar or related businesses, our operations always have some risk of environmental costs and liabilities because we handle petroleum products.

OUR USE OF DERIVATIVE FINANCIAL INSTRUMENTS COULD RESULT IN FINANCIAL LOSSES.

We use financial derivative instruments and other hedging mechanisms from time to time to limit a portion of the adverse effects resulting from changes in oil and natural gas commodity prices and interest rates, although there are times when we do not have any hedging mechanisms in place. To the extent we hedge our commodity price exposure and interest rate exposure, we forego the benefits we would otherwise experience if commodity prices were to increase or interest rates were to decrease. In addition, we could experience losses resulting from our hedging and other derivative positions. Such losses could occur under various circumstances, including if our counterparty does not perform its obligations under the hedge arrangement, our hedge is imperfect, or our hedging policies and procedures are not followed.

WE MAY BE ADVERSELY AFFECTED BY EL PASO CORPORATION'S INTENTIONS OF EXITING THE ENERGY TRADING BUSINESS.

El Paso Corporation announced on November 8, 2002 its intentions to exit the energy trading business. During the year ended December 31, 2002, transportation and storage contracts with El Paso Merchant Energy North America Company accounted for $33 million in revenue. If El Paso Merchant Energy North America abandons this contract and we are unable to successfully negotiate replacement contracts with unaffiliated parties, or if the replacement contracts are on less favorable terms, the effect on us will be adverse.

WE WILL FACE COMPETITION FROM THIRD PARTIES TO GATHER, TRANSPORT, PROCESS, FRACTIONATE, STORE OR OTHERWISE HANDLE OIL, NATURAL GAS AND OTHER PETROLEUM PRODUCTS.

Even if reserves exist in the areas accessed by our facilities and are ultimately produced, we may not be chosen by the producers to gather, transport, process, fractionate, store or otherwise handle any of these reserves. We compete with others, including producers of oil and natural gas, for any such production on the basis of many factors, including:

- geographic proximity to the production;

- costs of connection;

- available capacity;

- rates; and

- access to markets.

FERC REGULATION AND A CHANGING REGULATORY ENVIRONMENT COULD AFFECT OUR CASH FLOW.

The FERC extensively regulates certain of our energy infrastructure assets. This regulation extends to such matters as:

- rate structures;

- rates of return on equity;

- recovery of costs;

- the services that our regulated assets are permitted to perform;

- the acquisition, construction and disposition of assets; and

- to an extent, the level of competition in that regulated industry.

In September 2001, the 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 our HIOS natural gas pipeline and Petal natural gas storage facilities 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. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public hearing was held in May 2002, providing an opportunity to comment further on the NOPR. Following the conference, additional comments were filed by us. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in the form proposed would, at a minimum, place additional administrative and operational burdens on us.

If the standards of conduct NOPR is adopted by the FERC, we will be required to functionally separate our HIOS and Petal interstate facilities from our other entities. Under the proposed rule, we would be required to dedicate employees to manage and operate our interstate facilities independently from our other non-jurisdictional facilities. This employee group would be required to function independently and would be prohibited from communicating non-public transportation information to affiliates. Separate office facilities and systems would be necessary because of the requirement to restrict affiliate access to interstate transportation information. The NOPR also limits the sharing of employees and officers with non-regulated entities. Because of the loss of synergies and shared employee restrictions, a disposition of the interstate facilities may be necessary for us to effectively comply with the rule.

In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. The FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost of service based rate) continues to safeguard against a pipeline exercising market power, as well as other issues related to negotiated rate programs. At this time, we cannot predict the outcome of this NOI.

In August 2002, the FERC issued a NOPR requiring that all cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth: the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to, these arrangements. Finally, the NOPR proposes that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity must maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent must maintain investment grade credit ratings. In August 2002, comments were filed. The FERC held a public conference in September 2002, to discuss the issues raised in the comments. Representatives of companies from the gas and electric industries participated on a panel and uniformly agreed that the proposed regulations should be revised substantially and that the proposed capital balance and investment grade credit rating requirements would be excessive. At this time, we cannot predict the outcome of this NOPR.

Also in August 2002, FERC's Chief Accountant issued an Accounting Release, to be effective immediately, providing guidance on how companies should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. However, the Accounting Release did not address the proposed requirements that the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent have investment grade credit ratings. Requests for rehearing were filed in August 2002. The FERC has not yet acted on rehearing requests.

If the cash management NOPR is adopted by the FERC, our HIOS and Petal interstate facilities will no longer be permitted to participate in a money pool or cash management program. As a result, more frequent distributions or equity contributions may be needed in anticipation of monthly cash flow requirements for those interstate facilities. Also, separate credit facilities and resources may be required to support the capital and day-to-day activities for the interstate facilities separate from other of our subsidiaries and our primary bank accounts.

In April 2002, FERC and the Department of Transportation, Office of Pipeline Safety convened a technical conference to discuss how to clarify, expedite, and streamline permitting and approvals for interstate pipeline reconstruction in the event of disaster, whether natural or otherwise. In January 2003, FERC issued a NOPR proposing (1) expand the scope of construction activities authorized under a pipeline's blanket certificate to allow replacement of mainline facilities; (2) authorize a pipeline to commence reconstruction of the affected system without a waiting period; and (3) authorize automatic approval of construction that would be above the normal cost ceiling. Comments on the NOPR were due on February 27, 2003. At this time we cannot predict the outcome of this rulemaking.

In January, 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. We intend to submit comments on the NOPR, which are due on March 31, 2003. At this time, we cannot predict the outcome of this rulemaking.

Given the extent of this regulation, the extensive changes in FERC policy over the last several years, the evolving nature of regulation and the possibility for additional changes, the current regulatory regime may change and affect our financial position, results of operations or cash flows.

A NATURAL DISASTER, CATASTROPHE OR OTHER INTERRUPTION EVENT INVOLVING US COULD RESULT IN SEVERE PERSONAL INJURY, PROPERTY DAMAGE AND ENVIRONMENTAL DAMAGE, WHICH COULD CURTAIL OUR OPERATIONS AND OTHERWISE ADVERSELY AFFECT OUR CASH FLOW.

Some of our operations involve higher risks of severe personal injury, property damage and environmental damage, any of which could curtail our operations and otherwise expose us to liability and adversely affect our cash flow. For example, our natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. We also operate oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. Virtually all of our operations are exposed to the elements, including hurricanes, tornadoes, storms, floods and earthquakes.

If one or more facilities that are owned by us or that deliver oil, natural gas or other products to us is damaged or otherwise affected by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of our storage contracts obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' natural gas is in our possession. Any event that interrupts the fees generated by our energy infrastructure assets, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying our interest obligations as well as unitholder distributions and, accordingly, adversely impact the market price of our securities. Additionally, the proceeds of any property and business interruption insurance maintained by us may not be paid in a timely manner or be in an amount sufficient to meet our needs if such an event were to occur, and we may not be able to renew it or obtain other desirable insurance on commercially reasonable terms, if at all.

ARTHUR ANDERSEN LLP, THE PUBLIC ACCOUNTANTS THAT AUDITED THE 2000 FINANCIAL STATEMENTS OF OUR JOINT VENTURE POSEIDON OIL PIPELINE COMPANY, L.L.C., HAS BEEN CONVICTED OF A FELONY, WHICH MAY ADVERSELY AFFECT THE ABILITY OF ARTHUR ANDERSEN LLP TO SATISFY ANY CLAIMS THAT MAY ARISE OUT OF ARTHUR ANDERSEN LLP'S AUDIT OF POSEIDON'S FINANCIAL STATEMENTS. IN ADDITION, ARTHUR ANDERSEN LLP HAS NOT CONSENTED TO THE USE OF THEIR OPINION IN THIS FILING. BECAUSE OF THIS, YOUR ABILITY TO EVER CLAIM AGAINST ARTHUR ANDERSEN LLP MAY BE LIMITED.

Arthur Andersen LLP is the independent public accountant that audited the financial statements of our Poseidon joint venture for the year ended December 31, 2000. Arthur Andersen LLP was recently convicted of obstruction of justice in connection with the U.S. government's investigation of Enron Corp. Events arising out of this conviction may adversely affect the ability of Arthur Andersen LLP to satisfy any claims that may arise out of Arthur Andersen LLP's audits of Poseidon's financial statements. Additionally, because the personnel responsible for the audit of Poseidon's financial statements are no longer employed by Arthur Andersen LLP, we have not received Arthur Andersen LLP's consent with respect to the inclusion of those financial statements and the related audit report; accordingly, if those financial statements are inaccurate, your ability to make a claim against Arthur Andersen LLP may be limited or prohibited.

CONFLICTS OF INTEREST RISKS

EL PASO CORPORATION AND ITS SUBSIDIARIES HAVE CONFLICTS OF INTEREST WITH US AND, ACCORDINGLY, YOU.

We have potential and existing conflicts of interest with El Paso Corporation and its affiliates in four general areas:

- we have historically entered into transactions with each other, including some relating to operating and managing assets, acquiring and selling assets, and performing services;

- we share personnel, assets, systems and other resources;

- from time to time, we compete for business and customers; and

- from time to time, we both may have an interest in acquiring the same asset, business or other business opportunity.

We expect to continue to enter into transactions and other activities with El Paso Corporation and its subsidiaries because of the businesses and areas in which we and El Paso Corporation currently operate, as well as those in which we plan to operate in the future. Some more recent transactions in which we, on the one hand, and El Paso Corporation and its subsidiaries, on the other hand, had a conflict of interest include:

- in November 2002, we acquired the San Juan assets from El Paso Corporation for approximately $782 million, net $766 million adjusted for capital expenditures and actual working capital acquired;

- in April 2002, we acquired the EPN Holding assets from El Paso Corporation for approximately $735 million of net consideration; and

- pursuant to a general and administrative services agreement, subsidiaries of El Paso Corporation provide us administrative, operational and other services.

In addition, we and El Paso Corporation and its subsidiaries share and, therefore will compete for, the time and effort of El Paso Corporation personnel who provide services to us, including directors, officers and other personnel. Personnel of the general partner and its subsidiaries do not, and will not be required to, spend

any specified percentage or amount of time on our business. Since these shared personnel function as both our representatives and those of El Paso Corporation and its subsidiaries, conflicts of interest could arise between El Paso Corporation and its subsidiaries, on the one hand, and us and our unitholders, on the other. Additionally, some of these personnel own and have been awarded from time to time financial shares, or options to purchase shares, of El Paso Corporation; accordingly, their financial interests may not always be aligned completely with ours or those of our limited partners.

Some other situations in which an actual or potential conflict of interest arises between us, on the one hand, and our general partner or its affiliates (including El Paso Corporation), on the other hand, and there is a benefit to our general partner or its subsidiaries in which neither us nor our limited partners will share include:

- compensation paid to the general partner, which includes incentive distributions and reimbursements for reasonable general and administrative expenses;

- payments to the general partner and its affiliates for any services rendered to us or on our behalf;

- our general partner's determination of which direct and indirect costs we must reimburse; and

- our general partner's determination to establish cash reserves under certain circumstances and thereby decrease cash available for distributions to unitholders.

In addition, El Paso Corporation's beneficial ownership interest in our outstanding partnership interests could have a substantial effect on the outcome of some actions requiring partner approval. Accordingly, subject to legal requirements, El Paso Corporation makes the final determination regarding how any particular conflict of interest is resolved.

The interests of El Paso Corporation and its subsidiaries may not always be aligned with our interest, and, accordingly, they may not always act in your best interest. El Paso Corporation is neither contractually nor legally bound to use us as its primary vehicle for growth and development of midstream energy assets, and may reconsider at any time, without notice. Further, El Paso Corporation is not required to pursue any business strategy that will favor our business opportunities over the business opportunities of El Paso Corporation or any of its affiliates. El Paso Corporation and its subsidiaries (many of which are wholly owned) operate in some of the same lines of business and in some of the same geographic areas in which we operate.

BECAUSE WE DEPEND UPON EL PASO CORPORATION AND ITS SUBSIDIARIES FOR EMPLOYEES TO MANAGE OUR BUSINESS AND AFFAIRS, A DECREASE IN THE AVAILABILITY OF EMPLOYEES FROM EL PASO CORPORATION AND ITS AFFILIATES COULD ADVERSELY AFFECT US.

We have no employees. In managing our business and affairs, our general partner relies on employees of El Paso Corporation and its affiliates under a general and administrative services agreement between our general partner, on one hand, and subsidiaries of El Paso Corporation, on the other hand. Those employees will act on behalf of and as agents for us. A decrease in the availability of employees from El Paso Corporation and its affiliates could adversely affect us. Although this arrangement has worked well for us in the past and continues to work well for us, in accordance with our recently accounted Independence Initiatives, we are evaluating the direct employment of the personnel who manage the day-to-day operations of our assets.

DUE TO OUR SIGNIFICANT RELATIONSHIPS WITH EL PASO CORPORATION, ADVERSE DEVELOPMENTS CONCERNING EL PASO CORPORATION COULD ADVERSELY AFFECT US, EVEN IF WE HAVE NOT SUFFERED ANY SIMILAR DEVELOPMENTS.

Through its subsidiaries, El Paso Corporation owns 100 percent of our general partner and has historically, with its affiliates, employed the personnel who operate our businesses. El Paso Corporation is a significant stakeholder in our limited partner interests, and as with many other large energy companies, is a significant customer of ours. The outstanding senior unsecured indebtedness of El Paso Corporation has been downgraded to below investment grade, at least in part, as a result of the outlook for the consolidated business of El Paso Corporation and its need for liquidity. In the event that El Paso Corporation's liquidity needs are not satisfied, El Paso Corporation could be forced to seek protection from its creditors in bankruptcy. Although we are making efforts to implement new procedures and other mechanisms to better balance the risks and rewards of our significant relationships with El Paso Corporation and its affiliates, if El Paso Corporation continues to suffer financial stress, we may be adversely affected, even if we have not suffered any similar developments.

OUR GENERAL PARTNER AND ITS AFFILIATES MAY SELL UNITS OR OTHER LIMITED PARTNER INTERESTS IN THE TRADING MARKET, WHICH COULD REDUCE THE MARKET PRICE OF COMMON UNITS.

As of the date of this annual report, our general partner and its affiliates own 11,674,275 common units and 10,937,500 Series C units that may ultimately be converted into common units. In the future, they may acquire additional interest or dispose of some or all of their interest. If they were to dispose of a substantial portion of their interest in the trading markets, it could reduce the market price of common units. Our partnership agreement, and other agreements to which we are party, allow our general partner and certain of its subsidiaries to cause us to register for sale the partnership interests held by such persons, including common units. These registration rights allow our general partner and its subsidiaries to request registration of those partnership interests and to include any of those securities in a registration of other capital securities by us.

OUR PARTNERSHIP AGREEMENT PURPORTS TO LIMIT OUR GENERAL PARTNER'S FIDUCIARY DUTIES AND CERTAIN OTHER OBLIGATIONS RELATING TO US.

Although our general partner owes fiduciary duties to us and will be liable for all our debts, other than non-recourse debts, to the extent not paid by us, certain provisions of our partnership agreement contain exculpatory language purporting to limit the liability of our general partner to us and unitholders. For example, the partnership agreement provides that:

- borrowings of money by us, or the approval thereof by our general partner, will not constitute a breach of any duty of our general partner to us or you whether or not the purpose or effect of the borrowing is to permit distributions on our limited partner interests or to result in or increase incentive distributions to our general partner;

- any action taken by our general partner consistent with the standards of reasonable discretion set forth in certain definitions in our partnership agreement will be deemed not to breach any duty of our general partner to us or to unitholders; and

- in the absence of bad faith by our general partner, the resolution of conflicts of interest by our general partner will not constitute a breach of the partnership agreement or a breach of any standard of care or duty.

Provisions of the partnership agreement also purport to modify the fiduciary duty standards to which our general partner would otherwise be subject under Delaware law, under which a general partner owes its limited partners the highest duties of good faith, fairness and loyalty. The duty of loyalty would generally prohibit our general partner from taking any action or engaging in any transaction as to which it had a conflict of interest. The partnership agreement permits our general partner to exercise the discretion and authority granted to it in that agreement in managing us and in conducting its retained operations, so long as its actions are not inconsistent with our interests. Our general partner and its officers and directors may not be liable to us or to unitholders for certain actions or omissions which might otherwise be deemed to be a breach of fiduciary duty under Delaware or other applicable state law. Further, the partnership agreement requires us to indemnify our general partner to the fullest extent permitted by law, which indemnification, in light of the exculpatory provisions in the partnership agreement, could result in us indemnifying our general partner for negligent acts.

CASH RESERVES, EXPENDITURES AND OTHER MATTERS WITHIN THE DISCRETION OF OUR GENERAL PARTNER MAY AFFECT DISTRIBUTIONS TO UNITHOLDERS AND RESERVES FOR DEBT SERVICE.

Our general partner has broad discretion to make cash expenditures and to establish and make additions to cash reserves for any proper partnership purpose, including reserves for the purpose of:

- providing for future operating and capital expenditures;

- providing for debt service;

- providing funds for up to the next four quarterly distributions;

- providing funds to redeem or otherwise repurchase our outstanding debt or equity;

- stabilizing distributions of cash to capital security holders;

- complying with the terms of any agreement or obligation of ours; and

- providing for a discretionary reserve amount.

The timing and amount of additions to discretionary reserves could significantly reduce potential distributions that certain unitholders could receive or ultimately affect who gets the distribution. The reduction or elimination of a previously established reserve in a particular quarter will result in a higher level of cash available for distribution than would otherwise be available in such quarter. Depending upon the resulting level of cash available for distribution, our general partner may receive incentive distributions which it would not have otherwise received. Thus, our general partner could have a conflict of interest in determining the amount and timing of any increases or decreases in reserves. Our general partner receives the following compensation:

- distributions in respect of its general and limited partner interests in us;

- incentive distributions to the extent that available cash exceeds specified target levels that are over $0.325 per unit per quarter; and

- reimbursements for reasonable general and administrative expenses, and other reasonable expenses, incurred by our general partner and its subsidiaries for or on our behalf.

Our partnership agreement was not, and many of the other agreements, contracts and arrangements between us, on the one hand, and our general partner and its subsidiaries, on the other hand, were not and may not be the result of arm's-length negotiations and, as a result, those agreements may not be as profitable or advantageous to us and may produce a lower distribution for our unitholders than those negotiated at arm's-length.

In addition, increases to reserves (other than the discretionary reserve amount provided for in the partnership agreement) will reduce our cash from operations, which under certain limited circumstances could result in certain distributions to be attributable to interim capital transactions rather than to cash from operations. If a cash distribution was attributable to an interim capital transaction, (i) 99 percent of the distribution would be made pro rata to all limited partners, including the Series B preference unitholders and Series C unitholders, and (ii) the distribution would be deemed a return of a portion of an investor's investment in his partnership interest and would reduce each of our general partner's target distribution levels proportionately.

RISKS INHERENT IN AN INVESTMENT IN OUR SECURITIES

UNITHOLDERS HAVE LIMITED VOTING RIGHTS AND DO NOT CONTROL OUR GENERAL PARTNER.

Unlike the holder of capital stock in a corporation, unitholders have limited voting rights on matters affecting our business. Our general partner, whose directors unitholders do not elect, manages our activities. Our unitholders will have no right to elect our general partner on an annual or any other continuing basis. If our general partner voluntarily withdraws, however, the holders of a majority of our outstanding limited partner interests (excluding for purposes of such determination interests owned by the withdrawing general partner and its affiliates) may elect its successor.

Our general partner may not be removed as our general partner except upon approval by the affirmative vote of the holders of at least 55 percent of our outstanding limited partner interests (including limited partner interests owned by our general partner and its affiliates), subject to the satisfaction of certain conditions. Any removal of our general partner is not effective until the holders of a majority of our outstanding limited partner interests approve a successor general partner. Before the holders of outstanding limited partner interests may remove our general partner, they must receive an opinion of counsel that:

- such action will not result in the loss of limited liability of any limited partner or of any member of any of our subsidiaries or cause us or any of our subsidiaries to be taxable as a corporation or to be treated as an association taxable as a corporation for federal income tax purposes; and

- all required consents by any regulatory authorities have been obtained.

If our general partner were to withdraw or be removed as our general partner, that would effectively result in its concurrent withdrawal or removal as the manager of our subsidiaries.

WE MAY ISSUE ADDITIONAL SECURITIES, WHICH WILL DILUTE INTERESTS OF UNITHOLDERS AND MAY ADVERSELY EFFECT THEIR VOTING POWER.

We can issue additional common units, preference units and other capital securities representing limited partner interests, including securities with rights to distributions and allocations or in liquidation equal or superior to the equity securities held by existing unitholders, for any amount and on any terms and conditions established by our general partner. For example, in 2002, we issued 4,243,435 additional common units and 10,937,500 Series C units, which may ultimately convert into common units. If we issue more limited partner interests, it will reduce each common unitholder's proportionate ownership interest in us. This could cause the market price of the common units to fall and reduce the cash distributions paid to our limited partners. Further, we have the ability to issue partnership interests with voting rights superior to the unitholders. If we issue any such securities, it could adversely affect the voting power of the common units.

OUR GENERAL PARTNER HAS ANTI-DILUTION RIGHTS.

Whenever we issue equity securities to any person other than our general partner and its affiliates, our general partner and its affiliates have the right to purchase an additional amount of those equity securities on the same terms as they are issued to the other purchasers. This allows our general partner and its affiliates to maintain their percentage partnership interest in us. No other unitholder has a similar right. Therefore, only our general partner may protect itself against dilution caused by the issuance of additional equity securities.

UNITHOLDERS MAY NOT HAVE LIMITED LIABILITY IN THE CIRCUMSTANCES DESCRIBED BELOW, INCLUDING POTENTIALLY HAVING LIABILITY FOR THE RETURN OF WRONGFUL DISTRIBUTIONS.

We operate businesses in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas and plan to expand into more states. In some states (but not any of the states in which we currently do business), the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established. To the extent we conduct business in one of those states, a unitholder might be held liable for our obligations as if it was a general partner if:

- a court or government agency determined that we had not complied with that state's partnership statute; or

- our unitholders' rights to act together to remove or replace our general partner or take other actions under our partnership agreement were to constitute "control" of our business under that state's partnership statute.

A unitholder will not be liable for assessments in addition to its initial capital investment in any of our capital securities representing limited partnership interests. However, a unitholder may be required to repay to us any amounts wrongfully returned or distributed to it under some circumstances. Under Delaware law, we may not make a distribution to unitholders if the distribution causes our liabilities (other than liabilities to partners on account of their partnership interests and nonrecourse liabilities) to exceed the fair value of our assets. Delaware law provides that a limited partner who receives such a distribution and knew at the time of the distribution that the distribution violated the law will be liable to the limited partnership for the amount of the distribution for three years from the date of the distribution.

OUR GENERAL PARTNER HAS A LIMITED CALL RIGHT THAT MAY REQUIRE UNITHOLDERS TO SELL THEIR LIMITED PARTNER INTERESTS AT AN UNDESIRABLE TIME OR PRICE.

If at any time our general partner and its affiliates hold 85 percent or more of any class or series of our issued and outstanding limited partner interests, our general partner will have the right to purchase all, but not less than all, of the outstanding securities of that class or series held by nonaffiliates. This purchase would take place as of a record date which would be selected by our general partner, on at least 30 but not more than 60 days' notice. Our general partner may assign and transfer this call right to any of its affiliates or to us. If our general partner (or its assignee) exercises this call right, it must purchase the securities at the higher of (i) the highest cash price paid by our general partner or its affiliates for any unit or other limited partner interest of such class purchased within the 90 days preceding the date our general partner mails notice of the election to call the units or other limited partner interests or (ii) the average of the last reported sales price per unit or other limited partner interest of such class over the 20 trading days preceding the date five days before our general partner mails such notice. Accordingly, under certain circumstances unitholders may be required to sell their limited partner interests against their will and the price they receive for those securities may be less than they would like to receive.

OUR EXISTING UNITS ARE, AND POTENTIALLY ANY LIMITED PARTNER INTERESTS WE ISSUE IN THE FUTURE WILL BE, SUBJECT TO RESTRICTIONS ON TRANSFER.

All purchasers of our existing units, and potentially any purchasers of limited partner interests we issue in the future, who wish to become holders of record and receive cash distributions must deliver an executed transfer application in which the purchaser or transferee must certify that, among other things, he, she or it agrees to be bound by our partnership agreement and is eligible to purchase our securities. A person purchasing our existing units, or possibly limited partner interests we issue in the future, who does not execute a transfer application and certify that the purchaser is eligible to purchase those securities acquires no rights in those securities other than the right to resell those securities. Further, our general partner may request each record holder to furnish certain information, including that holder's nationality, citizenship or other related status. An investor who is not a U.S. resident may not be eligible to become a record holder or one of our limited partners if that investor's ownership would subject us to the risk of cancellation or forfeiture of any of our assets under any federal, state or local law or regulation. If the record holder fails to furnish the information or if our general partner determines, on the basis of the information furnished by the holder in response to the request, that such holder is not qualified to become one of our limited partners, our general partner may be substituted as a holder for the record holder, who will then be treated as a non-citizen assignee, and we will have the right to redeem those securities held by the record holder.

WE MAY NOT BE ABLE TO SATISFY OUR OBLIGATION TO REPURCHASE DEBT SECURITIES UPON A CHANGE OF CONTROL.

Upon a change of control (among other things, the acquisition of 50 percent or more of El Paso Corporation's voting stock, or if El Paso Corporation and its subsidiaries no longer own more than 50 percent of our general partner, or the sale of all or substantially all of our assets), unless our creditors agreed otherwise, we would be required to repay the amounts outstanding under our credit facilities and to offer to repurchase our outstanding senior subordinated notes at 101 percent of the principal amount, plus accrued and unpaid interest to the date of repurchase. We may not have sufficient funds available or be permitted by our other debt instruments to fulfill these obligations upon the occurrence of a change of control. We have publicly disclosed our efforts to further distinguish ourselves from El Paso Corporation. As a result of this announcement, and investors' perception that general partner investments are trading at lower than historical valuations, various parties have expressed an interest in purchasing all or a portion of our general partner. We have been entrusted by the owner of our general partner to meet with a limited number of such investors to gauge the level of their interest and will report back to El Paso Corporation on the outcomes of these meetings. El Paso Corporation has the sole responsibility of determining the ultimate ownership status of the general partner interest. We acknowledge that we are meeting with parties interested in acquiring an equity stake in the general partner but cannot confirm that such interest will result in firm proposals or, if such firm proposals are received, that El Paso Corporation will pursue such proposals.

RISKS RELATED TO OUR LEGAL STRUCTURE

THE INTERRUPTION OF DISTRIBUTIONS TO US FROM OUR SUBSIDIARIES AND JOINT VENTURES MAY AFFECT OUR ABILITY TO MAKE PAYMENTS ON OUR DEBT SECURITIES OR CASH DISTRIBUTIONS TO OUR UNITHOLDERS.

We are a holding company. As such, our primary assets are the capital stock and other equity interests in our subsidiaries and joint ventures. Consequently, our ability to fund our commitments (including payments on our debt securities) and to make cash distributions depends upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us. Distributions from our joint ventures are subject to the discretion of their respective management committees. In addition, from time to time, our joint ventures and some of our subsidiaries have separate credit arrangements that contain various restrictive covenants. Among other things, those covenants limit or restrict each such company's ability to make distributions to us under certain circumstances. Further, each joint venture's charter documents typically vest in its management committee sole discretion regarding distributions. Accordingly, our joint ventures and our unrestricted subsidiaries may not continue to make distributions to us at current levels or at all.

Moreover, pursuant to Deepwater Gateway's credit arrangements, we have agreed to return a limited amount of the distributions made to us by Deepwater Gateway if certain conditions exist.

WE CANNOT CAUSE OUR JOINT VENTURES TO TAKE OR NOT TO TAKE CERTAIN ACTIONS UNLESS SOME OR ALL OF OUR JOINT VENTURE PARTICIPANTS AGREE.

Due to the nature of joint ventures, each participant (including us) in each of our joint ventures, including Poseidon, Deepwater Gateway and Coyote Gas Treating, LLC, has made substantial investments (including contributions and other commitments) in that joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features include a corporate governance structure that requires at least a majority in interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100 percent) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, we cannot cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the particular joint venture or us. As of December 31, 2002, our aggregate investments in Deepwater Gateway, Coyote Gas Treating, L.L.C. and Poseidon totaled $33 million, $0.7 million and $40 million.

WE DO NOT HAVE THE SAME FLEXIBILITY AS OTHER TYPES OF ORGANIZATIONS TO ACCUMULATE CASH AND EQUITY TO PROTECT AGAINST ILLIQUIDITY IN THE FUTURE.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts reserved for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

CHANGES OF CONTROL OF OUR GENERAL PARTNER MAY ADVERSELY AFFECT YOU.

Our results of operations and, thus, our ability to pay amounts due under the debt securities and to make cash distributions could be adversely affected if there is a change of control of our general partner. For example, El Paso Corporation and its subsidiaries are parties to various credit agreements and other financing arrangements, the obligations of which may be collateralized (directly or indirectly). El Paso Corporation and its subsidiaries have used, and may use in the future, their interests, which include our general partner interest, common units, Series C units and Series B preference units as collateral. These arrangements may allow such lenders to foreclose on that collateral in the event of a default. Further, El Paso Corporation could sell our general partner or any of the common units or other limited partner interests it holds. El Paso Corporation's sale of 50 percent or more of our general partner would constitute a change of control under our existing credit agreement and indentures. In such a circumstance, our indebtedness for borrowed money would effectively become due and payable unless our creditors agreed otherwise, and we might be required to refinance our indebtedness, potentially on less advantageous terms. In addition, El Paso Corporation could sell control of our general partner to another company with less familiarity and experience with our businesses and with different business philosophies and objectives. In such a situation, we may not be able to refinance our indebtedness. Any such acquirer also may not continue our current business strategy, or even a business strategy economically compatible with our current business strategy.

TAX RISKS

WE HAVE NOT RECEIVED A RULING OR ASSURANCES FROM THE IRS ON ANY MATTERS AFFECTING US.

We have not requested, and do not intend to request, any ruling from the Internal Revenue Service (IRS) with respect to our classification, or the classification of any of our subsidiaries which are organized as limited liability companies or partnerships, as a partnership for federal income tax purposes. Accordingly, the IRS may propose positions that differ from the conclusions expressed by us. It may be necessary to resort to administrative or court proceedings in an effort to sustain some or all of those conclusions, and some or all of those conclusions ultimately may not be sustained. The limited partners and our general partner will bear, directly or indirectly, the costs of any contest with the IRS.

OUR TAX TREATMENT DEPENDS ON OUR PARTNERSHIP STATUS AND IF THE IRS TREATS US AS A CORPORATION FOR TAX PURPOSES, IT WOULD ADVERSELY AFFECT DISTRIBUTIONS TO OUR UNITHOLDERS AND OUR ABILITY TO MAKE PAYMENTS ON OUR DEBT SECURITIES.

Based upon the continued accuracy of the representations of our general partner, we believe that under current law and regulations we and our subsidiaries which are limited liability companies or partnerships have been and will continue to be classified as partnerships for federal income tax purposes or will be ignored as separate entities for federal income tax purposes. However, as stated above, we have not requested, and will not request, any ruling from the IRS as to this status. In addition, you cannot be sure that those representations will continue to be accurate. If the IRS were to challenge our federal income tax status or the status of one of our subsidiaries, such a challenge could result in (i) an audit of each unitholder's entire tax return and (ii) adjustments to items on that return that are unrelated to the ownership of units or other limited partner interests. In addition, each unitholder would bear the cost of any expenses incurred in connection with an examination of its personal tax return. Except as specifically noted, this discussion assumes that we and our subsidiaries which are organized as limited liability companies or partnerships have been and are treated as single member limited liability companies disregarded from their owners or partnerships for federal income tax purposes.

If we or any of our subsidiaries which are organized as limited liability companies, limited partnerships or general partnerships were taxable as a corporation for federal income tax purposes in any taxable year, its income, gains, losses and deductions would be reflected on its tax return rather than being passed through (proportionately) to unitholders, and its net income would be taxed at corporate rates. This would materially and adversely affect our ability to make payments on our debt securities. In addition, some or all of the distributions made to unitholders would be treated as dividend income and would be reduced as a result of the federal, state and local taxes paid by us or our subsidiaries.

WE MAINTAIN UNIFORMITY OF OUR LIMITED PARTNER INTERESTS THROUGH NONCONFORMING DEPRECIATION CONVENTIONS.

Since we cannot match transferors and transferees of our limited partner interests, we must maintain uniformity of the economic and tax characteristics of the limited partner interests to their purchasers. To maintain uniformity and for other reasons, we have adopted certain depreciation conventions. The IRS may challenge those conventions and, if such a challenge were sustained, the uniformity or the value of our limited partner interests may be affected. For example, non-uniformity could adversely affect the amount of tax depreciation available to unitholders and could have a negative impact on the value of their limited partner interests.

UNITHOLDERS CAN ONLY DEDUCT CERTAIN LOSSES.

Any losses that we generate will be available to offset future income (except certain portfolio net income) that we generate and cannot be used to offset income from any other source, including other passive activities or investments unless the unitholder disposes of its entire interest.

UNITHOLDERS' PARTNERSHIP TAX INFORMATION MAY BE AUDITED.

We will furnish each unitholder a Schedule K-1 that sets forth its allocable share of income, gains, losses and deductions. In preparing this schedule, we will use various accounting and reporting conventions and various depreciation and amortization methods we have adopted. We cannot guarantee that this schedule will yield a result that conforms to statutory or regulatory requirements or to administrative pronouncements of the IRS. Further, our tax return may be audited, and any such audit could result in an audit of each unitholder's individual tax return as well as increased liabilities for taxes because of adjustments resulting from the audit.

UNITHOLDERS' TAX LIABILITY RESULTING FROM AN INVESTMENT IN OUR LIMITED PARTNER INTERESTS COULD EXCEED ANY CASH UNITHOLDERS RECEIVE AS A DISTRIBUTION FROM US OR THE PROCEEDS FROM DISPOSITIONS OF THOSE SECURITIES.

A unitholder will be required to pay federal income tax and, in certain cases, state and local income taxes on its allocable share of our income, whether or not it receives any cash distributions from us. A unitholder may not receive cash distributions equal to its allocable share of taxable income from us. In fact, a unitholder may incur tax liability in excess of the amount of cash distribution we make to it or the cash it receives on the sale of its units or other limited partner interests.

TAX-EXEMPT ORGANIZATIONS AND CERTAIN OTHER INVESTORS MAY EXPERIENCE ADVERSE TAX CONSEQUENCES FROM OWNERSHIP OF OUR SECURITIES.

Investment in our securities by tax-exempt organizations and regulated investment companies raises issues unique to such persons. Virtually all of our income allocated to a tax-exempt organization will be unrelated business taxable income and will be taxable to such tax-exempt organization. Additionally, very little of our income will qualify for purposes of determining whether an investor will qualify as a regulated investment company. Furthermore, an investor who is a nonresident alien, a foreign corporation or other foreign person will be required to file federal income tax returns and to pay taxes on his share of our taxable income because he will be regarded as being engaged in a trade or business in the United States as a result of his ownership of units or other limited partnership units. We have the right to redeem units or other limited partner interests held by certain non-U.S. residents or holders otherwise not qualified to become one of our limited partners.

WE ARE REGISTERED AS A TAX SHELTER. ANY IRS AUDIT WHICH ADJUSTS OUR RETURNS WOULD ALSO ADJUST EACH UNITHOLDER'S RETURNS.

We have been registered with the IRS as a "tax shelter." The tax shelter registration number is 93084000079. As a result, we may be audited by the IRS and tax adjustments may be made. The right of a unitholder owning less than a one percent profit interest in us to participate in the income tax audit process is limited. Further, any adjustments in our tax returns will lead to adjustments in each unitholder's returns and may lead to audits of each unitholder's returns and adjustments of items unrelated to us. Each unitholder would bear the cost of any expenses incurred in connection with an examination of its personal tax return.

UNITHOLDERS MAY HAVE NEGATIVE TAX CONSEQUENCES IF WE DEFAULT ON OUR DEBT OR SELL ASSETS.

If we default on any of our debt, the lenders will have the right to sue us for non-payment. Such an action could cause an investment loss and cause negative tax consequences for each unitholder through the realization of taxable income by it without a corresponding cash distribution. Likewise, if we were to dispose of assets and realize a taxable gain while there is substantial debt outstanding and proceeds of the sale were applied to the debt, each unitholder could have increased taxable income without a corresponding cash distribution.

WE WILL TREAT EACH PURCHASER OF UNITS AS HAVING THE SAME TAX BENEFITS WITHOUT REGARD TO THE UNITS PURCHASED. THE IRS MAY CHALLENGE THIS TREATMENT, WHICH COULD ADVERSELY AFFECT THE VALUE OF THE UNITS.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization positions that could be challenged. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to your tax returns.

YOU WILL LIKELY BE SUBJECT TO STATE AND LOCAL TAXES IN STATES WHERE YOU DO NOT LIVE AS A RESULT OF AN INVESTMENT IN OUR UNITS.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property and in which you do not reside. You may be required to file state and local income tax returns and pay state and local income taxes in many or all of the jurisdictions in which we do business. Further, you may be subject to penalties for failure to comply with those requirements. We own assets and do business in six states. Four of these states currently impose a personal income tax on partners of partnerships doing business in those states but who are not residents of those states. It is your responsibility to file all United States federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We may utilize derivative financial instruments to manage our exposure to movements in interest rates and commodity prices. In accordance with procedures established by our general partner, we monitor current economic conditions and evaluate our expectations of future prices and interest rates when making decisions with respect to risk management. We generally do not enter into derivative transactions for trading purposes and had no trading activities during 2002 and 2001.

NON-TRADING COMMODITY PRICE RISK

A majority of our commodity sales and purchases 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.

Our customers and producers regularly negotiate contracts with us to provide natural gas gathering, treating and processing services for specific volumes of natural gas and NGL under which we receive variable rate fees that are based on an index plus a margin. In an effort to minimize fluctuations in our cash flow that may result from fluctuations in natural gas and NGL prices, we manage this price risk by simultaneously entering fixed-for-floating commodity price swaps for comparable volumes of natural gas and NGL that settle over the same time periods as the underlying contracts. These commodity price swap transactions are commonly referred to as "hedges," because if effective, they stabilize the amounts we receive for providing natural gas and NGL gathering, treating and processing services that would otherwise fluctuate with changes in natural gas and NGL prices. We settle the commodity price swap transactions by paying the negative difference or receiving the positive difference between the fixed price specified in the contract and the applicable settlement price indicated for the applicable index as published in the periodical "Inside FERC" for natural gas contracts and the price indicated by the Oil Pricing Information Service (OPIS) for NGL contracts for the specified commodity on the established settlement date. No ineffectiveness exists in our hedging relationships because all purchases and sales prices are based on the same index and volumes as the hedge transaction.

Our hedging activities also expose us to credit risk arising from the counterparty to the hedging transaction. We generally manage the credit risk by entering into derivative contracts with established organizations that have investment grade credit ratings from established credit ratings agencies (e.g., Standard & Poor's or Moody's Investors Services). We do not require collateral and do not anticipate non-performance by counterparties to our derivative transactions.

In August 2002 in anticipation of our acquisition of the San Juan assets, we entered into derivative financial instruments to receive fixed prices for specified volumes of natural gas for the 2003 calendar year. The derivative is a fixed-for-floating commodity price swap on 30,000 MMBtu/d of natural gas at a weighted average receive price of $3.525 per Dth for delivery through December 2003. Since the derivative was not associated with our then current operating activities, it did not qualify for hedge accounting under SFAS No. 133. As a result, we accounted for this commodity price swap based upon mark-to-market accounting until we acquired the San Juan assets on November 27, 2002. With the acquisition of the San Juan assets, we designated the previously acquired fixed-for-floating commodity price swaps as a cash flow hedge. We recognized a gain of $0.4 million in income for the change in value from the date we entered the derivative until the San Juan acquisition date.

In connection with our EPN Holding acquisition in April 2002, we obtained a 42.3 percent interest in the Indian Basin natural gas processing plant. Our Indian Basin plant provides NGL processing services for customers and receives a portion of the NGL processed as payment for these services, which we then sell at prevailing market prices. Due to fluctuations in the market price for NGL, we entered into fixed-for-floating commodity price swaps during 2002 whereby we receive a fixed price based on the daily average price for the specified contract month based upon the OPIS posting prices for the particular month for established volumes that settle over the same time periods we expect to receive NGL from our processing activities. All of the fixed-for-floating commodity price swaps associated with our Indian Basin plant were settled as of December 31, 2002.

During 2002, our EPIA operation entered into sales contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time at a fixed price based on the SONAT-Louisiana index (Southern Natural Pipeline index as published by the periodical "Inside FERC") plus a margin. We simultaneously entered into fixed-for-floating commodity price swaps for comparable volumes of natural gas at fixed prices indicated in the SONAT-Louisiana index that settle over the same time periods as the underlying sales contracts. The effect of these transactions is to fix the margins and substantially eliminate the price risk associated with our sales contracts.

No ineffectiveness exists in our hedging relationships because all purchase and sale prices are based on the same index and volumes as the hedge transactions. The following tables present information about our non-trading commodity price swaps at December 31:

EPIA	CONTRACT VALUE FIXED-FOR-FLOATING COMMODITY PRICE SWAPS 2002	2001
Contract volumes (in MDth)	95	765
Weighted average price received (per Dth)	$4.766	$ 2.533
Weighted average price paid (per Dth)	$3.862	$ 4.197
Swap Fair Value ($ in thousands) (a)	$ 86	$(1,272)

- ----------

(a) Fair value is determined from prices indicated in the SONAT-Louisiana index as developed from market data accumulated from a data base we maintain of executed commodity transactions.

SAN JUAN	CONTRACT VALUE FIXED-FOR-FLOATING COMMODITY PRICE SWAPS 2002	2001
Contract volumes (in MDth)	10,950	--
Weighted average price received (per Dth)	$ 3.525	--
Weighted average price paid (per Dth)	$ 3.963	--
Swap Fair Value ($ in thousands)(b)	$(4,796)	--

- ----------

(b) Fair value is determined from prices indicated in the San Juan index as developed from market data accumulated from a data base we maintain of executed commodity transactions.

As reflected in the tables above, at December 31, 2002 we have an unrealized loss associated with our natural gas fixed-for-floating commodity price swaps of approximately $4.7 million. Our exposure to market risk associated with commodity prices increased in 2002 as a result of our acquisitions of the Indian Basin plant and the San Juan assets due to the additional volumes of NGL and natural gas we buy and sell at market prices.

INTEREST RATE RISK

We utilize both fixed and variable rate long-term debt, and are exposed to market risk resulting from the variable interest rates under our credit facility, EPN Holding term credit facility and senior secured acquisition term loan. We are exposed to similar risk under the various joint venture credit facilities and loan agreements. Since we have $858 million outstanding under our indentures at fixed interest rates ranging from 8 1/2% to 10 5/8% at December 31, 2002, we have not benefited from the recent declines in interest rates. On the other hand, had interest rates increased, we would not have incurred additional interest costs.

The table below depicts principal cash flows and related weighted average interest rates of our debt obligations, by expected maturity dates at December

31, 2002. The carrying amounts of our revolving credit facility, EPN Holding term credit facility, the senior secured term loans and the limited recourse loan at December 31, 2002 and 2001, approximate the fair value of these instruments because the variable interest rates on these loans reprice frequently to reflect currently available interest rates. The fair value of the senior subordinated notes has been determined based on quoted market prices for the same or similar issues.

DECEMBER 31, 2002 -------

AVERAGE EXPECTED FISCAL
YEAR OF MATURITY OF
CARRYING AMOUNTS INTEREST

---------- FAIR RATE 2003
2004 2005 2006 2007
THEREAFTER TOTAL VALUE --
------ ---- ------ ------
---- ------ ---------- --
---- ------ (DOLLARS IN
MILLIONS) VARIABLE RATE
DEBT: Revolving credit
facility... 5.1% $--
$491.0 $ -- $-- $ -- $ --
$491.0 $491.0 EPN Holding
term credit
facility..................
4.9% -- -- 160.0 -- -- --
160.0 160.0 Senior
secured term loan....
5.2% 5.0 5.0 5.0 5.0
140.0 -- 160.0 160.0
Senior secured
acquisition term
loan..................
4.9% -- 237.5 -- -- -- --
237.5 237.5 Limited
recourse loan....... -- -
- -- -- -- -- -- -- --
FIXED RATE DEBT: 10 3/8%
senior subordinated notes
due 2009...........
10.4% -- -- -- -- --
175.0 175.0 186.4 8 1/2%
senior subordinated notes
due 2011........... 8.5%
-- -- -- -- -- 250.0
250.0 233.1 8 1/2% senior
subordinated notes due
2011........... 8.5% --
-- -- -- -- 230.0 230.0
214.5 10 5/8% senior
subordinated notes due
2012........... 10.6% --
-- -- -- -- 200.0 200.0
205.5
DECEMBER 31, 2001 -------
------------ CARRYING
FAIR AMOUNT VALUE -------
- ------ (DOLLARS IN
MILLIONS) VARIABLE RATE
DEBT: Revolving credit
facility... $300.0 $300.0
EPN Holding term credit
facility..................
N/A N/A Senior secured
term loan.... N/A N/A
Senior secured
acquisition term
loan................. N/A
N/A Limited recourse
loan....... 95.0 95.0
FIXED RATE DEBT: 10 3/8%
senior subordinated notes
due 2009...........
175.0 185.5 8 1/2% senior
subordinated notes due
2011........... 250.0
252.5 8 1/2% senior
subordinated notes due

2011............ N/A N/A
10 5/8% senior subordinated notes due
2012............ N/A N/A

At December 31, 2002, we had variable rate debt outstanding with an aggregate principal balance of $1,048.5 million and a weighted average interest rate of 5.1%. The following table illustrates the amount of the increase in net income from a decrease in interest rates or the amount of the decrease in income from an increase in interest rates under four possible scenarios based upon the aggregate balance of variable rate debt outstanding at December 31, 2002 (dollars in millions):

AGGREGATE VARIABLE-RATE DEBT SUBJECT TO REPRICING	EFFECT ON INCOME RESULTING FROM A CHANGE IN INTEREST RATES OF: 25 BASIS POINTS*	50 BASIS POINTS*	75 BASIS POINTS*	100 BASIS POINTS*
$1,048.5	$2.6	$5.2	$7.9	$10.5

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

* one basis point is equal to one one-hundredth of one percent.

Poseidon Oil Pipeline Company, L.L.C., one of our unconsolidated affiliates, has a revolving credit facility with $185 million of total borrowing capacity and $148 million outstanding at December 31, 2002. In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of the amounts outstanding on their variable rate revolving credit facility at 3.49% through January 2004. Poseidon, under its credit facility, currently pays an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Operating revenues			
Natural gas pipelines and plants			
Natural gas sales	$ 85,001	$ 59,701	$ 34,531
NGL sales	32,978	--	--
Gathering and transportation	194,336	33,849	28,968
Processing	45,266	7,133	--
	357,581	100,683	63,499
Oil and NGL logistics			
Oil sales	10,636	--	--
Oil transportation	8,364	7,082	8,307
Fractionation	26,356	25,245	--
NGL storage	2,817	--	--
	48,173	32,327	8,307
Platform services	16,672	15,385	13,875
Natural gas storage	28,602	19,373	6,182
Other -- oil and natural gas production	16,890	25,638	20,552
	467,918	193,406	112,415
Operating expenses			
Cost of natural gas, oil and other products	119,347	51,542	28,160
Operation and maintenance	115,162	33,279	14,461
Depreciation, depletion and amortization	72,126	34,778	27,743
Asset impairment charge	--	3,921	--
	306,635	123,520	70,364
Operating income	161,283	69,886	42,051
Other income (loss)			
Earnings from unconsolidated affiliates	13,639	8,449	22,931
Net loss on sale of assets	(473)	(11,367)	--
Minority interest in consolidated subsidiaries	60	(100)	(95)
Other income	1,537	28,726	2,377
Interest and debt expense	83,494	41,542	46,820
Income tax benefit	--	--	(305)
Income from continuing operations	92,552	54,052	20,749
Income (loss) from discontinued operations	5,136	1,097	(252)
Net income	$ 97,688	$ 55,149	$ 20,497

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Income (loss) allocation			
General partner			
Continuing operations	$ 42,082	$ 24,650	$ 15,581
Discontinued operations	51	11	(3)
	$ 42,133	$ 24,661	$ 15,578
Series B unitholders	$ 14,688	$ 17,228	$ 5,668
Series C unitholders	$ 1,507	$ --	$ --
Common unitholders			
Continuing operations	$ 34,275	$ 12,174	$ (500)
Discontinued operations	5,085	1,086	(249)
	$ 39,360	$ 13,260	$ (749)
Basic and diluted earnings per common unit			
Continuing operations	$ 0.80	$ 0.35	$ (0.02)
Discontinued operations	0.12	0.03	(0.01)
Net income (loss)	$ 0.92	$ 0.38	$ (0.03)
Weighted average number of common units outstanding	42,814	34,376	29,077

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS)

DECEMBER 31,	2002	2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 36,099	$ 13,084
Accounts receivable, net		
Trade	139,519	33,162
Affiliates	83,826	23,013
Affiliated note receivable	17,100	--
Other current assets	3,451	557
Total current assets	279,995	69,816
Property, plant and equipment, net	2,724,938	917,867
Intangible assets	3,970	--
Assets held for sale, net	--	185,560
Investment in processing agreement	--	119,981
Investments in unconsolidated affiliates	78,851	34,442
Other noncurrent assets	43,142	29,754
Total assets	$3,130,896	$1,357,420
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	$ 126,724	$ 14,987
Affiliates	86,144	10,068
Accrued interest	15,028	6,401
Current maturities of senior secured term loan	5,000	--
Current maturities of limited recourse term loan	--	19,000
Other current liabilities	21,195	4,159
Total current liabilities	254,091	54,615
Revolving credit facility	491,000	300,000
Senior secured term loans, less current maturities	552,500	--
Limited recourse term loan, less current maturities	--	76,000
Long-term debt	857,786	425,000
Other noncurrent liabilities	23,725	1,079
Total liabilities	2,179,102	856,694
Commitments and contingencies		
Minority interest	1,942	--
Partners' capital		
Limited partners		
Series B preference units; 125,392 units in 2002 and 2001 issued and outstanding	157,584	142,896
Series C units; 10,937,500 units in 2002 issued and outstanding	351,507	--
Accumulated other comprehensive loss allocated to Series C units' interest	(942)	--
Common units; 44,030,314 units in 2002 and 39,738,974 units in 2001 issued and outstanding	437,773	354,019
Accumulated other comprehensive loss allocated to common units' interest	(4,623)	(1,259)
General partner	8,610	5,083
Accumulated other comprehensive loss allocated to general partner's interests	(57)	(13)

- ---------- Total partners' capital........................... 949,852 500,726 --- ------- ---------- Total liabilities and partners' capital........... $3,130,896 $1,357,420 ========== ==========

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

YEAR ENDED DECEMBER 31,	2002	2001	2000
Cash flows from operating activities			
Net income	$ 97,688	$ 55,149	$ 20,497
Less income (loss) from discontinued operations	5,136	1,097	(252)
Income from continuing operations	92,552	54,052	20,749
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	72,126	34,778	27,743
Asset impairment charge	--	3,921	--
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	(13,639)	(8,449)	(22,931)
Distributions from unconsolidated affiliates	17,804	35,062	33,960
Net loss on sale of assets	473	11,367	--
Other noncash items	4,256	4,308	(13)
Working capital changes, net of effects of acquisitions and noncash transactions			
Accounts receivable	(169,106)	(41,954)	(17,351)
Other current assets	(3,144)	125	1,295
Accounts payable, accrued interest and other current liabilities	162,872	(259)	5,210
Noncurrent receivable from El Paso Corporation	8,437	(10,362)	--
Other	(1,875)	(173)	--
Net cash provided by continuing operations	170,756	82,416	48,662
Net cash provided by (used in) discontinued operations	5,244	4,968	(252)
Net cash provided by operating activities	176,000	87,384	48,410
Cash flows from investing activities			
Development expenditures for oil and natural gas properties	(1,682)	(2,018)	(172)
Additions to property, plant and equipment	(202,541)	(508,347)	(1,849)
Proceeds from sale of assets	5,460	109,126	--
Additions to investments in unconsolidated affiliates	(38,275)	(1,487)	(8,979)
Cash paid for acquisitions, net of cash acquired	(1,164,856)	(28,414)	(26,476)
Other	--	--	(381)
Net cash used in investing activities of continuing operations	(1,401,894)	(431,140)	(37,857)
Net cash provided by (used in) investing activities of discontinued operations	186,477	(68,560)	(88,356)
Net cash used in investing activities	(1,215,417)	(499,700)	(126,213)
Cash flows from financing activities			
Net proceeds from revolving credit facility	366,219	559,994	152,043
Repayments of revolving credit facility	(177,000)	(581,000)	(125,000)
Net proceeds from EPN Holding term credit facility	530,136	--	--
EPN Holding term credit facility repayments	(375,000)	--	--
Net proceeds from senior secured acquisition term loan	233,236	--	--
Net proceeds from senior secured term loan	156,530	--	--
Net proceeds from issuance of long-term debt	423,528	243,032	--
Argo term loan repayment	(95,000)	--	--
Net proceeds from issuance of common units	150,159	286,699	100,634
Redemption of Series B preference units	--	(50,000)	--
Redemption of publicly held preference			

units............. -- -- (804) Contributions from general partner........................ 4,095 2,843 2,785 Distributions to partners................................. (154,468) (106,409) (79,330) ----------- --------- --------- Net cash provided by financing activities of continuing operations.. 1,062,435 355,159 50,328 Net cash provided by (used in) financing activities of discontinued operations................................. (3) 49,960 43,554 ----------- --------- --------- Net cash provided by financing activities........... 1,062,432 405,119 93,882 ----------- --------- --------- Net increase (decrease) in cash and cash equivalents........ 23,015 (7,197) 16,079 Cash and cash equivalents at beginning of year.............. 13,084 20,281 4,202 ----------- --------- --------- Cash and cash equivalents at end of year.................... $ 36,099 $ 13,084 $ 20,281 =========== ========= =========

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(IN THOUSANDS)

SERIES B SERIES B
PREFERENCE PREFERENCE
SERIES C SERIES C
PREFERENCE PREFERENCE
COMMON COMMON UNITS
UNITHOLDERS UNITS(1)
UNITHOLDERS UNITS
UNITHOLDERS UNITS
UNITHOLDERS ---------- --
--------- -------- ------
----- ---------- --------
--- ------ -----------
Partners' capital at
January 1,
2000.......... -- $ -- -
- $ -- 290 $ 2,969 26,739
$ 93,277 Net income
(loss)(3)....... -- 5,668
-- -- -- 241 -- (990)
Conversion of preference
units into common
units... -- -- -- --
(211) (2,165) 211 2,165
Redemption of remaining
preference
units.......... -- -- --
-- (79) (804) -- --
Issuance of common
units... -- -- -- -- -- -
- 4,600 100,634 General
partner contribution
related to the issuance
of common
units.....................
-- -- -- -- -- -- -- --
Issuance of Series B
preference
units.......... 170
170,000 -- -- -- -- -- --
Cash
distributions......... --
-- -- -- -- (241) --
(62,284) --- -------- ---
--- -------- ---- -------
- ------ ---------
Partners' capital at
December 31,
2000......... 170 175,668
-- -- -- -- 31,550
132,802 Net
income(3).............. -
- 17,228 -- -- -- -- --
13,260 Other
comprehensive loss... --
-- -- -- -- -- -- (1,259)
Issuance of common
units... -- -- -- -- -- -
- 8,189 286,699
Unamortized unit option
compensation.............
-- -- -- -- -- 2,161
Redemption of Series B
preference
units.......... (45)
(50,000) -- -- -- -- -- -
- General partner
contribution related to
the issuance of common
units.....................
-- -- -- -- -- -- -- --
Cash
distributions......... --
-- -- -- -- -- --
(80,903) --- -------- ---

--- -------- ---- -------- ------ ---------
Partners' capital at December 31, 2001......... 125 142,896 -- -- -- -- 39,739 352,760 Net income(3).............. -- 14,688 -- 1,507 -- -- -- 39,360 Issuance of Series C units..................... -- -- 10,938 350,000 -- -- -- -- Other comprehensive loss... -- -- -- (942) -- -- -- (3,364) Issuance of common units... -- -- -- -- -- -- 4,291 156,072 Unamortized unit option compensation.............. -- -- -- -- -- -- -- 89 General partner contribution related to the issuance of Series C units and common units.... -- -- -- -- -- -- -- -- Cash distributions......... -- -- -- -- -- -- -- (111,767) --- -------- ------ -------- ---- -------- ------ ---------
Partners' capital at December 31, 2002......... 125 $157,584 10,938 $350,565 -- $ -- 44,030 $ 433,150 === ======== ====== ======== ==== ======== ====== =========
GENERAL PARTNER(2) TOTAL ---------- ---------
Partners' capital at January 1, 2000........... $ 243 $ 96,489 Net income (loss) (3)....... 15,578 20,497 Conversion of preference units into common units... -- -- Redemption of remaining preference units.......... -- (804) Issuance of common units... -- 100,634 General partner contribution related to the issuance of common units..................... 2,785 2,785 Issuance of Series B preference units.......... -- 170,000 Cash distributions......... (16,005) (78,530) -------- --------- Partners' capital at December 31, 2000......... 2,601 311,071 Net income(3).............. 24,661 55,149 Other comprehensive loss... (13) (1,272) Issuance of common units... -- 286,699 Unamortized unit option compensation.............. -- 2,161 Redemption of Series B preference units.......... -- (50,000) General partner

contribution related to the issuance of common units..................... 2,843 2,843 Cash distributions......... (25,022) (105,925) -------- --------- Partners' capital at December 31, 2001......... 5,070 500,726 Net income(3).............. 42,133 97,688 Issuance of Series C units...................... -- 350,000 Other comprehensive loss... (44) (4,350) Issuance of common units... -- 156,072 Unamortized unit option compensation.............. -- 89 General partner contribution related to the issuance of Series C units and common units.... 4,095 4,095 Cash distributions......... (42,701) (154,468) -------- --------- Partners' capital at December 31, 2002......... $ 8,553 $ 949,852 ======== =========

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

(1) We issued 10,937,500 of our Series C units to El Paso Corporation for a value of $350 million in connection with our acquisition of the San Juan assets. A discussion of this new class of units is included in Note 8.
(2) El Paso Energy Partners Company, a wholly owned subsidiary of El Paso Corporation, owns a one percent general partner interest in us.
(3) 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,		
	2002	2001	2000
Net income	$97,688	$55,149	$20,497
Other comprehensive income (loss)	(4,350)	(1,272)	--
Total comprehensive income	$93,338	$53,877	$20,497

ACCUMULATED OTHER COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
Beginning balance	$(1,272)	$ --	$ --
Unrealized mark-to-market losses on cash flow hedges arising during period	(6,428)	(1,682)	--
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	1,579	410	--
Accumulated other comprehensive income from investment in unconsolidated affiliate	499	--	--
Ending balance	$(5,622)	$(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, 2002, we had 44,030,314 common units outstanding representing limited partner interests, 125,392 Series B preference units outstanding representing preference interests and 10,937,500 Series C units outstanding representing non-voting limited partner interests. On that date, the public owned 32,356,069 common units, or 73.5 percent of our outstanding common units, and El Paso Corporation, through its subsidiaries, owned 11,674,245 common units, or 26.5 percent of our outstanding common units, all of our Series B preference units, all of our Series C units 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. During 2002, third parties have minority ownership interests in Matagorda Island Area Gathering System and Arizona Gas, L.L.C. The assets, liabilities and operations of these entities are included in our financial statements and we account for the third party ownership interest as minority interest in our balance sheet and as minority interest in consolidated subsidiaries in our statement of income. Our consolidated financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or partners' capital. We have reflected the results of operations from our Prince assets disposition as discontinued operations for all periods presented. See Note 2 for a further discussion of our Prince assets disposition.

Use of Estimates

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

Accounting for Regulated Operations

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

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts which may become uncollectible. Collectibility is reviewed regularly and the allowance is adjusted as necessary, primarily under the specific identification method. At December 31, 2002 and 2001, the allowance was $2.5 million and $1.8 million.

Natural Gas Imbalances

Natural gas imbalances result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. These imbalances are settled in kind through a tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure and are valued at prices representing the estimated value of these imbalances upon settlement. Changes in natural gas prices may impact our valuation. We do not value our imbalances based on current month prices because it is not likely that we would purchase or receive natural gas at that point in time to settle the imbalance. Natural gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our accompanying consolidated balance sheets. Our imbalances at December 31, 2002, arose as a result of our acquisitions during 2002. We did not have significant imbalances at December 31, 2001. Our imbalance receivables and imbalance payables were as follows at December 31, 2002 (in thousands):

Imbalance Receivables	
Trade	$ 88,929
Affiliates	$ 15,460
Imbalance Payables	
Trade	$104,035
Affiliates	$ 22,316

Property, Plant and Equipment

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

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 depreciated on a straight-line basis over the estimated useful lives which are as follows:

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

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

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

Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depreciation provisions for gathering pipelines, platforms, related facilities and oil and natural gas properties. At December 31, 2002 and 2001, accrued abandonment costs were $24.6 million and $23.5 million. As discussed below, upon our adoption of SFAS No. 143 Accounting for Asset Retirement Obligations the amounts accrued and capitalized will be adjusted to conform to the provisions of that statement.

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

Goodwill and Other Intangible Assets

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

As of December 31, 2002 and 2001, the carrying amount of our equity investment in Poseidon exceeded the underlying equity in net assets by approximately $3.0 million. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount and will test for impairment if an event occurs that indicates there may be a loss in value. Prior to January 1, 2002, we amortized this excess amount using the straight line method over approximately 30 years. This excess amount is reflected on our accompanying consolidated balance sheets in investments in unconsolidated affiliates. Our adoption of this statement did not have a material impact on our financial position or results of operations.

As part of our acquisition of the EPN Holding assets and the San Juan assets, we obtained intangible assets representing contractual rights under dedication and transportation agreements with producers. As of December 31, 2002, the value of these intangible assets was approximately $4.0 million and is reflected on our accompanying consolidated balance sheet as intangible assets. We amortize these intangible assets to expense using the units-of-production method over the expected lives of the reserves ranging from 20 to 45 years.

Impairment and Disposal of Long-Lived Assets

We adopted the provisions of SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets on January 1, 2002. Accordingly, we evaluate the recoverability of selected long-lived assets when adverse events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. We determine the recoverability of an asset or group of assets by estimating the undiscounted cash flows expected to result from the use and eventual disposition of the asset or group of assets at the lowest level for which separate cash flows can be measured. If the total of the undiscounted cash flows is less that the carrying amount for the assets, we estimate the fair value of the asset or group of assets and recognize the amount by which the carrying value exceeds the fair value as an impairment loss in income from operations in the period the impairment is determined.

Additionally, as required by SFAS No. 144, we classify long-lived assets to be disposed of other than by sale (e.g., abandonment, exchange or distribution) as held and used until the item is abandoned, exchanged or distributed. We evaluate assets to be disposed of other than by sale for impairment and recognize a loss for the excess of the carrying value over the fair value. Long-lived assets to be disposed of through sale recognition meeting specific criteria are classified as "Held for Sale" and measured at the lower of their cost or fair value less cost to sell. We report the results of operations of a component classified as held for sale, including any gain or loss recognized in discontinued operations in the period(s) in which they occur and all prior periods presented.

Capitalization of Interest

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

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness using the effective interest method. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated. At December 31, 2002 and 2001, the unamortized amount of our debt issue costs included in other noncurrent assets was $32.6 million and $17.0 million.

Revenue Recognition and Cost of Natural Gas, Oil and Other Products

Revenue from gathering and transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from commodity sales is recognized upon delivery. Commodity storage revenues and platform access revenues consist primarily of fixed fees for capacity reservation and some of the transportation contracts on our Viosca Knoll system and our Indian Basin lateral also contain a fixed fee to reserve transportation capacity. These fixed fees are recognized during the month in which the capacity is reserved by the customer, regardless of how much capacity is actually used. Revenue from processing services, treating services and fractionation services is recognized in the period the services are provided. Interruptible revenues from natural gas storage, which are generated by providing excess storage capacity, are variable in nature and are recognized when the service is provided. Other revenues generally are recorded when services have been provided or products have been delivered.

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

Typhoon Oil Pipeline's transportation agreement with BHP and Chevron Texaco provides that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. We reflect these sales in our revenues and the related purchases as cost of oil.

Environmental Costs

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

Accounting for Price Risk Management Activities

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

- exchange-traded future contracts that involve cash settlement;

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

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

Beginning in 2001, we account for all our derivative instruments in our financial statements under SFAS No. 133, Accounting for Derivatives and Hedging Activities. We record all derivatives in our balance sheet at their fair value as other assets or other liabilities and classify them as current or noncurrent based upon their anticipated settlement date.

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

During 2000, prior to our adoption of SFAS No. 133, 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.

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

During 2002 and 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 reclassify the gains or losses resulting from the sale, maturity, extinguishment or termination of derivative instruments designated as hedges from accumulated other comprehensive income to operating income in our consolidated statements of income. We classify cash inflows and outflows associated with the settlement of our derivative transactions as cash flows from operating activities in our consolidated statements of cash flows.

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

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

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

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, 2002, neither we nor any of our subsidiaries are taxable entities. Tarpon Transmission Company, our only taxable entity in 2000, was sold in January 2001, and as a result, we incurred no income tax liability in 2001 and 2002. 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 statement of income for the year ended 2000 relates solely to Tarpon's book loss at the effective statutory income tax rate for the respective period since no material differences existed between book and taxable income. In January 2001, we sold our interest in Tarpon as a result of a FTC order. All of Tarpon's deferred tax liabilities were assumed by the buyer at the time of sale.

Income (Loss) per Common Unit

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

Basic income (loss) per common unit and diluted income (loss) per common unit are the same for the years ended December 31, 2002, 2001, and 2000, 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 2000 in the basic and diluted net income (loss) per common 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 associated with our EPIA operations, our Indian Basin processing plant, the San Juan assets and our unconsolidated affiliate, Poseidon Oil Pipeline Company, L.L.C.

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.

In December 2002, the Financial Accounting Standards Board (FASB) issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. This statement amends SFAS No. 123, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the methods of accounting for stock-based employee compensation and the effect of the method used on reported results. This statement is effective for the fiscal years ending after December 15, 2002. We have decided that we will continue to use APB No. 25 to value our stock-based compensation and will include data providing the pro forma income impacts of using the fair value method as required by SFAS No. 148.

The following discloses our stock-based compensation impact on net income as required by SFAS No. 148. If compensation expense for the stock-based compensation plans under our Omnibus Plan and Director Plan, as described in Note 8, accounted for under APB 25, had been determined applying the provisions of SFAS No. 123, and using the Black-Scholes weighted average fair value of options granted as described in Note 8, our net income (loss) allocated to the common unitholders and net income (loss) per common unit for 2002, 2001, and 2000 would approximate the pro forma amounts below:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)		
Net income (loss) allocated to common unitholders, as reported	$39,360	$13,260	$ (749)
Less: Incremental stock-based employee compensation expense determined under fair value based method	(744)	(311)	(211)
Pro forma net income (loss) allocated to common unitholders	$38,616	$12,949	$ (960)
Basic and diluted earnings per common unit, as reported	$ 0.92	$ 0.38	$(0.03)
Basic and diluted earnings per common unit, pro forma	$ 0.90	$ 0.38	$(0.03)

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

Business Combinations

In July 2001, the 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.

New Accounting Pronouncements Issued But Not Yet Adopted

Accounting for Asset Retirement Obligations. In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement requires companies to record a liability for the estimated retirement and removal of assets used in their business. The liability is recorded at its fair value, with a corresponding asset which is depreciated over the remaining useful life of the long-lived asset to which the liability relates.

An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002 and relates primarily to our obligations to plug abandoned wells. We expect that we will record a cumulative effect of accounting change of approximately $1.7 million, as an increase to income upon our adoption of SFAS No. 143 on January 1, 2003. We also expect to record non-current retirement assets of approximately $7.0 million with useful lives ranging from 11 to 19 years and non-current retirement liabilities of approximately $5.3 million on January 1, 2003.

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

Reporting Gains and Losses from the Early Extinguishment of Debt. In April 2002, the FASB issued SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. This statement addresses how to report gains or losses resulting from the early extinguishment of debt. Previously, any gains or losses were reported as an extraordinary item. Upon adoption of SFAS No. 145, an entity will be required to evaluate whether the debt extinguishment is extraordinary in nature, or whether they should be included in income from continuing operations. This statement is effective for our 2003 year-end reporting.

Accounting for Costs Associated with Exit or Disposal Activities. In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs, associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activities. This statement is effective for fiscal years beginning after December 31, 2002 and will impact any exit or disposal activities that we initiate after January 1, 2003.

Accounting for Guarantees. In November 2002, the FASB issued FASB Interpretation (FIN) No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. This interpretation requires that companies record a liability for all guarantees issued after December 31, 2002, including financial, performance, and fair value guarantees. This liability is recorded at its fair value upon issuance, and does not affect any existing guarantees issued before January 31, 2003. This standard also requires expanded disclosures on all existing guarantees at December 31, 2002. We have included the required disclosures in Note 10.

Consolidation of Variable Interest Entities. In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities. This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003 for all variable interest entities created before January 31, 2003. We do not believe this statement will have any effect on us.

2. ACQUISITIONS AND DISPOSITIONS

San Juan Assets

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

- 100 percent of El Paso Field Services' San Juan Gathering and Processing Businesses, which include a natural gas gathering system and related compression facilities, the Rattlesnake Treating Plant, a

50-percent equity interest in Coyote Gas Treating, L.L.C. which owns the Coyote natural gas treating facility and the remaining interests in the Chaco cryogenic natural gas processing plant we did not already own, all of which are located in the San Juan Basin of northwest New Mexico and southwestern Colorado;

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

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

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

We purchased the San Juan assets for $782 million, $766 million after adjustments for capital expenditures and actual working capital acquired. We financed the purchase of these assets with net proceeds from an offering of $200 million of 10 5/8% Senior Subordinated Notes due 2012, borrowings of $237.5 million under our senior secured acquisition term loan, our issuance, to El Paso Corporation, of $350 million representing 10,937,500 of our Series C units valued at $32 per unit and currently available funds. We acquired the San Juan assets because they are strategically located in active supply development areas and are supported by long-term contracts that provide us with growing and reliable cash flows consistent with our stated growth strategy.

In connection with this acquisition, El Paso Corporation is required, subject to specified conditions, to repurchase the Chaco plant from us for $77 million in October 2021, and at that time we have the right to lease the plant from them for a period of 10 years with the option to renew the lease annually thereafter.

As a result of our acquisition of the San Juan assets, our financial results from the operation of the Chaco plant is significantly different from our results prior to the purchase as follows:

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

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

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

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

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at November 27, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal. The purchase price allocation is subject to modification pending validation of working capital balances (in thousands):

	AT NOVEMBER 27, 2002
Note receivable	$ 17,100
Property, plant and equipment	763,280
Intangible assets	470
Investment in unconsolidated affiliate	2,500
Total assets acquired	783,350
Imbalances payable	15,601
Other current liabilities	1,543
Total liabilities assumed	17,144
Net assets acquired	$766,206

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we are amortizing to expense using the units-of-production method over the expected lives of the underlying reserves of approximately 20 years. We recorded adjustments to the purchase price of approximately $16 million primarily for capital expenditures and actual working capital acquired. The purchase price allocation is subject to further adjustment as new information becomes available regarding the working capital accounts we acquired.

Our consolidated financial statements include the results of operations of the San Juan assets from the November 27, 2002 purchase date. We have included the assets and operating results of the El Paso Field Services' San Juan Gathering and Processing Businesses and the Typhoon Gas Pipeline in our natural gas pipelines and plants segment and the assets and operating results of the Typhoon Oil Pipeline and Coastal Liquids Partners' NGL Business in our oil and NGL logistics segment from the purchase date. The following selected unaudited pro forma financial information presents our consolidated operating results for the years ended December 31, 2002 and 2001 as if we acquired the San Juan assets on January 1, 2001:

	2002	2001
	(IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)	
Operating revenues	$837,647	$511,335
Income from continuing operations	$ 88,902	$ 77,219
Income allocated to common unitholders from continuing operations	$ 25,738	$ 16,687
Basic and diluted net income per unit from continuing operations	$ 0.60	$ 0.43

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

EPN Holding Assets

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

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

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

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

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

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

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

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

We acquired the EPN Holding assets to provide us with a significant new source of cash flow, greater diversification of our midstream asset base and to provide new long term internal growth opportunities in the Texas intrastate market. We purchased the EPN Holding assets for $750 million, adjusted for the assumption of $15 million of working capital related to natural gas imbalances resulting in net consideration of $735 million comprised of the following:

- $420 million of cash;

- $119 million of assumed short-term indebtedness payable to El Paso Corporation, which we subsequently repaid;

- $6 million in common units; and

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

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

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at April 8, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal. The purchase price allocation is subject to modification pending validation of working capital balances (in thousands):

	AT APRIL 8, 2002
Current assets	$ 2,217
Property, plant and equipment	775,997
Intangible assets	3,500
Total assets acquired	781,714
Current liabilities	25,578
Environmental liabilities	21,136
Total liabilities assumed	46,714
Net assets acquired	$735,000

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we will amortize to expense using the units-of-production method over the expected lives of the underlying reserves ranging from 26 to 45 years. Additionally, we assumed environmental liabilities of $21.1 million for estimated environmental remediation costs associated with the EPGT Texas intrastate pipeline assets as discussed in Note 10.

Our consolidated financial statements include the results of operations of the EPN Holding assets from the April 8, 2002 purchase date. We have included the assets and operating results of the Waha, Carlsbad and Warwink natural gas gathering systems; the Channel and TPC Offshore pipeline systems; and the EPGT Texas pipeline assets (excluding the Wilson Storage facility) in our natural gas pipelines and plants segment. Our 42.3 percent ownership interest in the assets and operating results of the Indian Basin plant are included in our oil and NGL logistics segment and the Wilson storage facility assets and operating results are included in our natural gas storage segment. The following selected unaudited pro forma information depicts our consolidated results of operations for the years ended December 31, 2002 and 2001 as if we acquired the EPN Holding assets on January 1, 2001:

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

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

Prince Assets

In connection with our April 2002 acquisition of the EPN Holding assets from El Paso Corporation, we sold our Prince tension leg platform (TLP), and our nine percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation. The results of operations for these assets have been accounted for as discontinued operations and have been excluded from continuing operations for all periods in our statements of income. Accordingly, the segment results in Note 14 reflect neither the results of operations for the Prince

assets nor the related net assets held for sale. The Prince TLP was previously included in the Platform services segment and related royalty interest was included in the Other segment. Included in income from discontinued operations for the years ended December 31, 2002 and 2001 were revenues of $7.8 million and $8.8 million attributable to these disposed assets. We did not recognize any revenues related to the Prince assets during the year ended December 31, 2000, since these assets were not placed in service until September 2001.

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

	DECEMBER 31, 2001 (IN THOUSANDS)
Property, plant and equipment	$189,432
Accumulated depreciation	(3,872)
Assets held for sale, net	185,560
Unamortized debt issue cost	1,091
Argo term loan	(95,000)
Accrued interest on Argo term loan	(703)
Net assets related to the Prince assets disposition	$ 90,948

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

Deepwater Holdings L.L.C. and Chaco Transaction

In October 2001, we acquired the remaining 50 percent interest that we did not already own in Deepwater Holdings for approximately $81 million, consisting of $26 million cash and $55 million of assumed indebtedness, and at the acquisition date also repaid all of Deepwater Holdings $110 million of indebtedness. HIOS and East Breaks became indirect wholly-owned assets through this transaction. In a separate transaction, we acquired the Chaco cryogenic natural gas processing plant for $198.5 million. The total purchase price was composed of a payment of $77 million to acquire the plant from the bank group that provided the financing for the construction of the facility and a payment of $121.5 million to El Paso Field Services in connection with the execution of a 20-year fee-based processing agreement relating to the processing capacity of the Chaco plant and dedication of natural gas gathered by El Paso Field Services to the Chaco plant. Under the terms of the processing agreement, we received a fixed fee for each dekatherm of natural gas that we processed at the Chaco plant, and we bore all costs associated with the plant's ownership and operations. El Paso Field Services personnel continued to operate the plant. In accordance with the original construction financing agreements, the Chaco plant was under an operating lease to El Paso Field Services. El Paso Field Services had the right to repurchase the Chaco Plant at the end of the lease term in October 2002 for approximately $77 million. We funded both of these transactions by borrowing from our revolving credit facility. We accounted for these transactions as purchases and have assigned the purchase price to the net assets acquired based upon the estimated fair value of the net assets as of the acquisition date. The operating results associated with Deepwater Holdings are included in earnings from unconsolidated affiliates for the periods prior to October 2001. We have included the operating results of Deepwater Holdings and the Chaco plant in our consolidated financial statements from the acquisition date.

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

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

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

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 500 miles of NGL gathering and transportation pipelines. The NGL pipeline system gathers and transports unfractionated and fractionated products. We also acquired three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGL into ethane, propane, butane and natural gasoline products that are used by refineries and petrochemical plants along the Texas Gulf Coast. We accounted for the acquisition as a purchase and assigned the purchase price to the assets acquired based upon the estimated fair value of the assets as of the acquisition date. We have included the operating results of 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, UTOS, Nautilus, Manta Ray Offshore, Nemo, Tarpon, and the Green Canyon pipeline assets, as well as interests in two offshore platforms and one dehydration facility. We recognized net losses from the asset sales of approximately $12 million, and Deepwater Holdings recognized losses of approximately $21 million. Our share of Deepwater Holdings losses was approximately $14 million, which has been reflected in earnings from unconsolidated affiliates in the accompanying 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 three years beginning in 2001 and ending with a $2 million payment 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 year ended December 31, 2000, assuming we acquired EPIA and the Crystal natural gas storage businesses on January 1, 2000:

	2000 (IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)
Operating revenues...	$131,426
Operating income..	$ 45,171
Net income allocated to limited partners..................	$ 1,887
Basic and diluted net income per unit.....................	$ 0.06

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

	AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2002			
	COYOTE(A)	POSEIDON	DEEPWATER GATEWAY(B)	TOTAL
	(IN THOUSANDS)			
END OF PERIOD OWNERSHIP INTEREST	50%	36%	50%	
OPERATING RESULTS DATA:				
Operating revenues	$ 635	$1,086,757	$ --	
Crude oil purchases	--	1,032,496	--	
Gross margin	635	54,261	--	
Other income	2	26,695	20	
Operating expenses	(38)	(4,691)	--	
Depreciation	(110)	(8,356)	--	
Other expenses	(75)	(6,923)	(234)	
Net income (loss)	$ 414	$ 60,986	$ (214)	
OUR SHARE:				
Allocated income (loss)	$ 207	$ 21,955	$ (107)	
Adjustments(c)	(13)	(8,510)	107	
Earnings from unconsolidated affiliate	$ 194	$ 13,445	$ --	$13,639
Allocated distributions	$ 2,000	$ 15,804	$ --	$17,804
FINANCIAL POSITION DATA:				
Current assets	$ 1,575	$ 152,784	$ 10,745	
Noncurrent assets	33,349	218,463	110,309	
Current liabilities	34,559	119,974	28,268	
Noncurrent liabilities	--	148,000	27,000	

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

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

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

AS OF OR FOR THE YEAR ENDED DECEMBER 31, 2001	DEEPWATER HOLDINGS(A)	POSEIDON	DIVESTED INVESTMENTS(B)	OTHER(C)	TOTAL
(IN THOUSANDS)					
END OF PERIOD OWNERSHIP INTEREST.......	100%	36%	--	50%	
OPERATING RESULTS DATA:					
Operating revenues...................	$ 40,933	$1,196,840	$1,982	$145	
Crude oil purchases.................	--	1,126,439	--	--	
Gross margin........................	40,933	70,401	1,982	145	
Other income (loss)..................	--	394	(85)	--	
Operating expenses...................	(16,740)	(1,586)	(590)	(73)	
Depreciation.........................	(8,899)	(10,552)	(953)	--	
Other (expenses) income.............	(5,868)	(7,668)	222	(22)	
Loss on sale of assets..............	(21,453)	--	--	--	
Net income (loss)....................	$(12,027)	$ 50,989	$ 576	$ 50	
OUR SHARE:					
Allocated income (loss) (d)...........	$ (9,925)	$ 18,356	$ 148	$ 25	
Adjustments(e).......................	--	(146)	(9)	--	
Earnings (loss) from unconsolidated affiliates.......................	$ (9,925)	$ 18,210	$ 139	$ 25	$ 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	
Noncurrent liabilities..............		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) Through October 2001 this company processed gas for Deepwater Holdings' Stingray subsidiary. This agreement was terminated in October 2001, and as of this date there are no operations related to this investment.
(d) The income (loss) from Deepwater Holdings is not allocated proportionately with our ownership percentage because the capital contributed by us was a

larger amount of the total capital at the time of formation. Therefore, we were allocated a larger amount of amortization of Deepwater Holdings' excess purchase price of its investments. Also, we were allocated a larger portion of Deepwater Holdings' $21 million loss incurred in 2001 due to the sale of Stingray, UTOS, and the West Cameron dehydration facility. Our total share of the losses relating to these sales was approximately $14 million.

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

	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	$1,466,086	$ 26,478	$110	
Crude oil purchases	--	1,402,721	--	--	
Gross margin	67,122	63,365	26,478	110	
Other income	532	639	2,301	--	
Operating expenses	(25,279)	(22,605)	(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	
Noncurrent liabilities	166,517	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 earnings reported in our Annual Report on Form 10-K and actual earnings reported in the 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.

4. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

DECEMBER 31,	2002	2001
	(IN THOUSANDS)	
Property, plant and equipment, at cost		
Pipelines	$2,317,503	$ 856,335
Platforms and facilities	128,582	125,546
Processing plants	300,897	138,090
Oil and natural gas properties	127,975	125,665
Storage facilities	331,562	156,800
Construction work-in-progress	177,964	99,667
	3,384,483	1,502,103
Less accumulated depreciation, depletion and amortization	659,545	584,236
Total property, plant and equipment, net	$2,724,938	$ 917,867

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. As a result of the San Juan acquisition in November 2002, we now own the gathering system and related facilities previously owned by El Paso Field Services, including the rights of El Paso Field Services under the arrangements relating to the Chaco plant. Prior to this acquisition, our investment in the processing agreement was being amortized on a straight-line basis over the life of the agreement and we recorded amortization expense of $5.6 million in 2002 and $1.5 million in 2001 related to this asset. Under the processing agreement, all previously uncommitted volumes on El Paso Field Services' San Juan Gathering System were dedicated to the Chaco plant. As part of the agreement, natural gas delivered to the Chaco plant by El Paso Field Services had a processing priority over other natural gas.

6. FINANCING TRANSACTIONS

In October 2002, we amended the terms of our $600 million revolving credit facility and the EPN Holding term credit facility in connection with our entering into the senior secured term loan. The modifications included, among other things, (1) entering into a new $160 million senior secured term loan maturing in 2007 as a term component of our revolving credit facility, which we collectively refer to as our credit facility; (2) designating the EPN Holding term credit facility as "senior secured" indebtedness, in addition to our credit facility which is cross-collateralized on an equal basis with all of the collateral currently pledged under our credit facility and the EPN Holding term credit facility; (3) aligning, effectively, the covenants in our credit facility and the EPN Holding term credit facility, including eliminating the restrictions for distributing cash out of EPN Holding; and (4) terminating the $25 million revolving credit facility that was formerly part of the EPN Holding term credit facility.

In November 2002, we further amended our credit facility and the EPN Holding term credit facility in connection with our borrowing of $237.5 million under the senior secured acquisition term loan to modify the interest rates the facilities bear. The modified interest rate we are charged under the terms of the amendment will remain in effect until the senior secured acquisition term loan is repaid in full. Under the amended terms of these agreements, the loans bear interest at our option at either (i) 2.25% plus a variable base rate (equal to the greater of the prime rate as determined by JP Morgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JP Morgan Chase Bank plus 1.00%); or (ii) LIBOR plus 3.50%. Our credit facility, the EPN Holding term credit facility, senior secured term loan and the senior secured acquisition term loan are discussed below.

CREDIT FACILITY

Revolving Credit Facility

As of December 31, 2002, we had $491 million outstanding with an average interest rate of 5.14% under our $600 million revolving credit facility with the total unused amount available. The applicable rates on our revolving credit facility will revert to the historical rate schedule at LIBOR plus rates ranging from 0.875% to 2.50% or one of the variable base rates described above plus rates ranging from 0.0% to 1.50% following repayment of the $237.5 million senior secured acquisition term loan, subject to our meeting certain ratios and attaining certain ratings as set forth in our credit facility. Our interest rate is contingent upon our leverage ratio, as defined in our credit facility, and ratings we are assigned by S&P or Moody's on our long-term unsecured debt. The interest rate we are charged would increase by 0.50% if the credit ratings on our senior unsecured debt are decreased, or, alternatively, would decrease by 0.25% if these ratings are increased or our leverage ratio improves. We pay commitment fees on the unused portion of our revolving credit facility at rates that vary from 0.25% to 0.50% per year. The revolving credit facility matures in May 2004, is guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries (Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and EPN Arizona Gas, L.L.C.), El Paso Energy Partners Finance Corporation and our general partner, and is cross-collateralized with our other credit facilities by substantially all of our assets (excluding our unrestricted subsidiaries) and our general partner's general and administrative services agreement. The covenants and events of default governing the revolving credit facility are described under Credit Facilities Covenants.

Senior Secured Term Loan

In October 2002, in connection with the amendment of our credit facilities discussed above, we obtained a $160 million senior secured term loan with a syndicate of lenders which we used to temporarily reduce indebtedness under our $600 million revolving credit facility. We may elect that all or a portion of the senior secured term loan bear interest at either 2.25% plus a variable base rate (equal to the greater of the prime rate as determined by JP Morgan Chase Bank, the federal funds rate plus 0.5% or the CD rate as determined by JP Morgan Chase Bank plus 1%); or LIBOR plus 3.5%. We may, at our option, make prepayments in amounts not less than $5 million. The senior secured term loan is payable in semi-annual installments of $2.5 million in April and October of each year beginning April 2003 for the first nine installments and the remaining balance at maturity in October 2007. The senior secured term loan is guaranteed by us, all of our subsidiaries (other than our unrestricted subsidiaries) and our general partner; and is cross-collateralized with our credit facility, the EPN Holding term credit facility, and our senior secured acquisition term loan by substantially all of our assets (excluding our unrestricted subsidiaries) and by our general partner's general and administrative services agreement. As of December 2002 we had $160 million outstanding with an average interest rate of 5.22%. The covenants and events of default governing this loan are described under Credit Facilities Covenants.

EPN Holding Term Credit Facility

In connection with our acquisition of the EPN Holding assets from El Paso Corporation in April 2002, EPN Holding entered into a $560 million term credit facility with a group of commercial banks. The term credit facility provided a term loan (the EPN Holding term loan) of $535 million to finance the acquisition of the EPN Holding assets, and a revolving credit facility (the EPN Holding revolving credit facility) of up to $25 million to finance EPN Holding's working capital. EPN Holding's obligations under the term credit facility are guaranteed by us, all of our subsidiaries (other than our unrestricted subsidiaries,), El Paso Energy Partners Finance Corporation and our general partner and is cross-collateralized with our other credit facilities by substantially all of our assets (excluding our unrestricted subsidiaries) and by our general partner's general and administrative services agreement. At the time of its acquisition, EPN Holding borrowed $535 million ($531 million, net of issuance costs) under this term loan and had $25 million available under the EPN Holding revolving credit facility which we have subsequently terminated. The EPN Holding term loan matures in April 2005. We used net proceeds of approximately $149 million from our April 2002 common unit offering, $0.6 million contributed by our general partner to maintain its one percent capital account balance and $225 million of the net proceeds from our May 2002 offering of 8 1/2% Senior Subordinated Notes to reduce indebtedness under the term loan. As of December 31, 2002, the outstanding balance under the EPN Holding term credit facility was $160 million with an average interest rate of 4.92%. Following our repayment of the senior secured acquisition term loan, the interest rate we are charged on balances outstanding under the EPN Holding term credit facility will revert to the historical rate schedule at LIBOR plus rates ranging from 1.75% to 2.50% or one of the variable base rates described above plus rates ranging from 0.50% to 1.25%, subject to our meeting certain ratios set forth in the EPN Holding term credit facility. The interest rate we are charged would increase by 0.25% if our leverage ratio deteriorates to 5.00 to 1.00 or greater, or would decrease by 0.25% if our leverage ratio improves to 4.00 to 1.00 or less. The covenants and events of default governing this credit facility are described under Credit Facilities Covenants.

Senior Secured Acquisition Term Loan

As part of the San Juan assets acquisition, we entered into a $237.5 million senior secured acquisition term loan to fund a portion of the $766 million purchase price of the San Juan assets. The loan bears interest at our option at either (i) 2.25% plus a variable rate (equal to the greater of the prime rate as determined by JP Morgan Chase Bank, the federal funds rate plus ..05% or the CD rate as determined by JP Morgan Chase Bank plus 1%); or (ii) LIBOR plus 3.5% and is subject to a grid based on our credit ratings. The interest rate we are charged on balances outstanding under the senior secured acquisition term loan is dependent on the ratings we are assigned by S&P and Moody's on our senior secured long-term bank debt. Our interest rate is increased by 1.00% when our senior secured long-term bank debt is rated below the higher of BB+ by S&P and Ba1 by Moody's. At December 31, 2002, we had $237.5 million outstanding with an average interest rate of 4.95%. We repaid the senior secured acquisition term loan in March 2003 with proceeds from our issuance of $300 million 8 1/2% Senior Subordinated Notes.

Credit Facilities Covenants

Our credit facility, the EPN Holding term credit facility and our senior secured acquisition term loan contain covenants that include restrictions on our and our subsidiaries' ability to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies and amend some of our contracts, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries and restrict our ability to make distributions to our unitholders. The financial covenants associated with these facilities are as follows:

(a) Consolidated tangible net worth cannot be less than $710.0 million plus 75 percent of the net proceeds we receive from future sales or issuance of any equity securities by us;

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

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

(d) The ratio of our consolidated total indebtedness on the last day of any fiscal quarter through December 31, 2003 to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 5.25 to 1.0. The ratio of consolidated total indebtedness to consolidated EBITDA will decline to 5.0 to 1.0 beginning January 1, 2004.

Among other things, each credit agreement includes as an event of default the failure of El Paso Corporation and its subsidiaries to own more than 50 percent of our general partner unless our creditors agree otherwise. We are in compliance with the financial ratios and covenants contained in each of our credit facilities at December 31, 2002. We have available for use the entire $109 million remaining under our revolving credit facility.

SENIOR SUBORDINATED NOTES

Each issue of our senior subordinated notes is subordinated in right of payment to all existing and future senior debt including our credit facility, the EPN Holding term credit facility and our senior secured acquisition term loan. Additionally, our subordinated notes include provisions that, among other things, restrict our and our subsidiaries ability to acquire assets, incur additional indebtedness or liens, sell assets, acquire or be acquired by other companies, and enter into sale and lease-back transactions unless we meet certain financial ratios and other specific conditions. These restrictive covenants will be suspended should our notes be rated Baa3 or higher by Moody's or BBB- or higher by S&P.

In November 2002, we issued $200 million in aggregate principal amount of 10 5/8% Senior Subordinated Notes. These notes bear interest of 10 5/8% per year, payable semi-annually in June and December, and mature in December 2012. These notes were issued for $198 million, net of discount of $1.5 million to yield 10.75% (proceeds of $194 million, net of issuance costs) which we used to fund a portion of the acquisition of the San Juan assets. These notes are subject to a registration rights agreement whereby, we are required to register these notes on Form S-4 with the SEC within 150 days of their issuance or under certain circumstances be subject to penalties of approximately $10,000 per week until a registration statement is filed with the SEC and declared effective. On February 28, 2003, we filed a Form S-4 with the SEC, however, it has not been declared effective. We may, at our option, prior to December 1, 2005, redeem up to 33 percent of the originally issued aggregate principal amount of the notes at a redemption price of 110.625%. On or after December 1, 2007, we may redeem all or part of these notes at 105.313% of the principal amount.

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

In May 2001, we issued $250 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. 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. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%. On or after June 1, 2006, we may redeem all or part of these notes at 104.250% of the principal amount.

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

Our subsidiaries, except El Paso Energy Partners Finance Corporation and our unrestricted subsidiaries, have guaranteed our obligations under all of the issuances of senior subordinated notes described above. In addition, we could be required to repurchase the senior subordinated notes if certain circumstances relating to change of control or asset dispositions exist. We are currently in compliance with the financial ratios and covenants contained in each of our senior subordinated notes at December 31, 2002.

ARGO TERM LOAN

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

OTHER CREDIT FACILITIES

Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, is party to a $185 million credit agreement under which it has outstanding obligations that may restrict its ability to pay distributions to its owners.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of the $148 million outstanding under its credit facility at 3.49% through January 2004. Poseidon, under its credit facility, currently pays an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. The interest rates Poseidon is charged on balances outstanding under its credit facility is dependent on their leverage ratio as defined in the Poseidon credit facility. Poseidon's interest rate at December 31, 2002 was LIBOR plus 1.50% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 0.50% for Base Rate loans. Poseidon's interest rates will decrease by 0.25% if their leverage ratio declines below 2.00 to 1.00 or by 0.50% if their leverage ratio declines to 1.00 to 1.00 or less. Additionally, Poseidon pays commitment fees on the unused portion of the credit facility at rates that vary from 0.25% to 0.375%. This credit agreement requires Poseidon to maintain a debt service reserve equal to two quarters interest and is collateralized by substantially all of Poseidon's assets. As of December 31, 2002, the remaining $73 million was at an average interest rate of 3.38%.

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

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

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

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

(c) the ratio of total indebtedness of Poseidon to EBITDA for the four quarters ending on the last day of the current quarter shall not exceed 3.00 to 1.00.

Poseidon was in compliance with the above covenants as of December 31, 2002.

In August 2002, Deepwater Gateway, our joint venture that is constructing the Marco Polo TLP, obtained a $155 million project finance loan from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. Deepwater Gateway may elect that all or a portion of the project finance loan bear interest at either i) LIBOR plus 1.75% or ii) an alternate base rate (equal to the greater of the prime rate, the base CD rate plus 1% or the federal funds rate plus 0.5%, as those terms are defined in the project finance loan agreement) plus 0.75%. Deepwater Gateway must also pay commitment fees of 0.375% per year on the unused portion of the project finance loan. The loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the project finance loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2002, Deepwater Gateway had $27 million outstanding under the project finance loan at an average interest rate of 3.38% and had not paid us or any of our subsidiaries any distributions.

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

DEBT MATURITY TABLE

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

2003	$ 5,000
2004	733,500
2005	165,000
2006	5,000
2007	140,000
Thereafter	855,000
Total long-term debt and other financing obligations, including current maturities	$1,903,500

In March 2003, we issued $300 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. These notes bear interest of 8 1/2% per year, payable semi-annually in June and December and matures in June 2010. These notes were issued at par and were used to repay the $238 million senior secured acquisition term loan and temporarily reduce our revolving credit facility.

INTEREST EXPENSE

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

	2002	2001	2000
	(IN THOUSANDS)		
Interest expense incurred	$89,956	$ 54,885	$51,076
Interest capitalized	(5,571)	(11,755)	(4,005)
Net interest expense	$84,385	$ 43,130	$47,071
Less: Interest expense on discontinued operations	891	1,588	251
Net interest expense on continuing operations	$83,494	$ 41,542	$46,820

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:

	2002		2001	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(IN MILLIONS)			
Liabilities:				
Revolving credit facility	$491.0	$491.0	$300.0	$300.0
EPN Holding term credit facility	160.0	160.0	--	--
Senior secured term loan	160.0	160.0	--	--
Senior secured acquisition term loan	237.5	237.5	--	--
Limited recourse term loan	--	--	95.0	95.0
10 3/8% Senior Subordinated Notes	175.0	186.4	175.0	185.5
8 1/2% Senior Subordinated Notes	250.0	233.1	250.0	252.5
8 1/2% Senior Subordinated Notes	234.3	214.5	--	--
10 5/8% Senior Subordinated Notes	198.5	205.5	--	--
Non-trading derivative instruments				
Commodity swap and forward contracts	$ 4.7	$ 4.7	$ 1.3	$ 1.3

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

	2002			2001		
	NOTIONAL VOLUME		MAXIMUM TERM IN YEARS	NOTIONAL VOLUME		MAXIMUM TERM IN YEARS
	BUY	SELL		BUY	SELL	
Commodity Natural Gas (MDth)	95	10,950	<1	765	--	<1

As of December 31, 2002, and 2001, 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 the variable interest rates on these loans reprice frequently to reflect currently available interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments from prices indicated for the same or similar commodity transactions for a specific index.

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of our customers' failure to pay. Our customers are concentrated in the energy sector, and the creditworthiness of several industry participants have been called into question. We maintain credit policies to minimize overall credit risk. We monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

8. PARTNERS' CAPITAL

General

As of December 31, 2002, we had 44,030,314 common units outstanding. Common units totaling 32,356,069 are owned by the public, representing a 73.5 percent common unit interest in us. As of December 31, 2002, El Paso Corporation, through its subsidiaries, owned 11,674,245 common units, or 26.5 percent of our outstanding common units, all of our 125,392 Series B preference units (with a liquidation value of $158 million), all of our 10,937,500 Series C units and our one percent general partner interest.

Offering of Common Units

In April 2002, we completed simultaneous offerings of 4,083,938 common units, which included a public offering of 3,000,000 common units and a private offering, at the same unit price, of 1,083,938 common units to our general partner (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. We used the net cash proceeds of approximately $149 million to reduce indebtedness under EPN Holding's term credit facility. Also in April 2002, we issued in a private offering 159,497 common units at the then-current market price of $37.74 per unit to a subsidiary of El Paso Corporation as partial consideration for our acquisition of the EPN Holding assets. In addition, our general partner contributed approximately $0.6 million in cash to us in April 2002 in order to maintain its one percent capital account balance.

In October 2001, we completed simultaneous offerings 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 (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. 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 170,000 Series B preference units with a value of $170 million to acquire the Petal and Hattiesburg natural gas storage businesses. 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, 2002, the liquidation value of the outstanding Series B preference units was approximately $158 million. These 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.

Series C Units

In November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of Series C units at a price of $32 per unit, $350 million in the aggregate, as part of our consideration paid for the San Juan assets. The issuance of the Series C units was an exempt transaction under Section 4(2) of the Securities Act of 1993 as a transaction not involving a public offering. The Series C units are similar to our existing common units, except that the Series C units are non-voting. After April 30, 2003, the holder of the Series C units will have the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit can convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C units will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate will increase on April 30, 2004, to 110 percent of the common unit distribution rate and on April 30, 2005, to 115 percent of the common unit distribution rate. In addition, our general partner contributed $3.5 million to us in order to satisfy its one percent capital contribution requirement.

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, Series C 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, 2002:

MONTH PAID(1)	COMMON UNIT	COMMON UNITHOLDERS	GENERAL PARTNER
	(PER UNIT)	(IN MILLIONS)	
February	$0.625	$24.8	$ 8.9
May	$0.650	$28.6	$10.9
August	$0.650	$28.6	$10.9
November	$0.675	$29.7	$12.0

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(1) Our Series C units are not included in the above table since they did not receive a distribution until February 2003.

In January 2003, we declared a cash distribution of $0.675 per common and Series C unit, $37.1 million in aggregate, which we paid on February 14, 2003. In addition, we paid distributions to our general partner of $14.6 million in respect of its general partner interest. At the current distribution rates, our general partner receives approximately 29 percent of our total cash distributions for its role as our general partner.

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. No grants of unit options were made in 2002.

In August 1998, we also 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 may designate. Restricted units awards representing 5,429 and 4,090 were granted during 2002 and 2001 with a grant price of $32.23 and $33.00 per unit. No restricted units were granted in 2000. As of December 31, 2002, 7,066 restricted units were outstanding. The value of these units is determined based on the fair market value on the grant date and this cost is amortized to compensation expense over the period of service, which we have estimated to be one year.

We have reflected the issuance of the restricted units as deferred compensation and as an increase in common units. This deferred compensation was approximately $175 thousand and $135 thousand in 2002 and 2001. Our 2001 deferred compensation is fully amortized. The unamortized amount of our total deferred compensation as of December 31, 2002, was approximately $1.2 million.

The following table summarizes activity under the Omnibus Plan and Director Plan (excluding our restricted units) as of and for the years ended December 31, 2002, 2001 and 2000.

	2002		2001		2000	
	# 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	1,614,500	$32.09	925,500	$27.15	937,500	$27.16
Granted	8,000	32.23	1,016,500	35.00	3,000	25.56
Exercised	42,500	27.19	307,500	27.17	--	--
Forfeited	--	--	--	--	7,500	27.19
Canceled	30,000	34.99	20,000	27.19	7,500	27.19
Outstanding at end of year	1,550,000	$32.17	1,614,500	$32.09	925,500	$27.15
Options exercisable at end of year	1,068,500	$30.88	606,500	$27.22	925,500	$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	2002	2001	2000
Expected term in years	8	8	8
Expected volatility	31.05%	27.50%	27.97%
Expected distributions	8.09%	9.55%	9.35%
Risk-free interest rate	3.24%	5.05%	5.35%

The Black-Scholes weighted average fair value of options granted during 2002, 2001, and 2000 was $3.71, $2.62, and $2.63 per unit option, respectively.

Options outstanding as of December 31, 2002, are summarized below:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
$19.86 to $27.80	555,500	5.6	$27.18	555,500	$27.18
$27.80 to $39.72	994,500	8.8	$34.95	513,000	$34.91
$19.86 to $39.72	1,550,000	7.5	$32.17	1,068,500	$30.88

9. RELATED PARTY TRANSACTIONS

The majority of our related party transactions are with affiliates of our general partner. Under an agreement that was in place before an indirect subsidiary of El Paso Corporation purchased our general partner, an affiliate our general partner was obligated to provide individuals to perform the day to day financial, administrative, accounting and operational functions for us. As our activities increased, the fee for such services has also increased. Further, we provide services to various El Paso subsidiaries and, in turn, they provide us services. In addition, we have acquired a number of assets from subsidiaries of El Paso Corporation.

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

	2002	2001	2000
	(IN THOUSANDS)		
Revenues received from related parties:			
Natural gas pipelines and plants	$159,608	$20,710	$ 9,356
Oil and NGL Logistics	26,288	25,249	--
Platform services(1)	--	35	146
Natural gas storage	3,016	2,325	1,268
Other(1)	9,809	5,676	15,722
	$198,721	$53,995	$26,492
Expenses paid to related parties:			
Purchased natural gas costs	$ 22,784	$34,768	$16,751
Operation and maintenance	60,458	33,721	22,817
	$ 83,242	$68,489	$39,568
Reimbursements received from related parties:			
Operation and maintenance	$ 2,100	$11,499	$20,543

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(1) In addition to revenues from continuing operations reflected above, we also received revenues from related parties in 2002 and 2001 of $6.8 million and $8.2 million for our Prince TLP and $1.0 million and $0.7 million for our 9 percent overriding royalty interest which are included in income from discontinued operations on our income statements.

For the years ended December 31, 2002, 2001 and 2000, revenues received from related parties consisted of approximately 42%, 28% and 24% of our revenue from continuing operations.

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

	2002	2001	2000
	(IN THOUSANDS)		
Revenues received from related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	$ 92,675	$16,433	$21,832
El Paso Production Company(1)	9,054	4,230	4,303
Southern Natural Gas Company	112	277	155
Tennessee Gas Pipeline Company	--	638	56
El Paso Field Services	96,880	32,382	--
Unconsolidated Subsidiaries			
Manta Ray Offshore(2)	--	35	146
	$198,721	$53,995	$26,492
Purchased natural gas costs paid to related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	$ 19,226	$28,169	$14,454
El Paso Production Company	2,251	6,412	2,160
Southern Natural Gas Company	245	187	137
Tennessee Gas Pipeline Company	70	--	--
El Paso Field Services	950	--	--
El Paso Natural Gas Company	42	--	--
	$ 22,784	$34,768	$16,751
Operating expenses paid to related parties:			
El Paso Corporation			
El Paso Field Services	$ 60,000	$33,187	$22,265
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company	458	534	552
	$ 60,458	$33,721	$22,817
Reimbursements received from related parties:			
Unconsolidated Subsidiaries			
Deepwater Holdings(3)	$ --	$ 9,399	$20,344
Poseidon Oil Pipeline Company	2,100	2,100	--
Manta Ray Offshore(2)	--	--	199
	$ 2,100	$11,499	$20,543

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(1) In addition to revenues from continuing operations from El Paso Production Company reflected above, during 2002 and 2001 we also received revenues of $7.8 million and $8.9 million from El Paso Production Company which are included in income from discontinued operations in our income statements.

(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) 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 Holding Assets. Our revenues from related parties increased in 2002 as a result of our EPN Holding transaction in which we acquired gathering, transportation and processing contracts with affiliates of our general partner. For the year ended December 31, 2002, we received $68.9 million from El Paso Merchant Energy North America Company, $35.8 million from El Paso Field Services and $4.0 million from El Paso Production Company.

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 years ended December 31, 2002 and 2001, we received revenue of approximately $26.0 million and $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 years ended December 31, 2002 and 2001, we received revenue of $29.6 million and $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 years ended December 31, 2002 and 2001, we received $1.8 million and $0.6 million related to this lease. As a result of the San Juan asset acquisition, the processing agreement and the operating lease were terminated.

Storage facilities. With the April 2002 acquisition of the EPN Holding assets, we purchased contracts held by Wilson Storage with El Paso Merchant Energy North America Company. For the year ended December 31, 2002 we received approximately $2.9 million from El Paso Merchant Energy North America Company for natural gas storage fees. El Paso Merchant Energy North America Company and Tennessee Gas Pipeline Company use our Petal and Hattiesburg storage facilities from time to time. For the years ended December 31, 2002, 2001, and the four months ended December 31, 2000 we received approximately $0.1 million, $1.6 million and $1.2 million from El Paso Merchant Energy North America Company for natural gas storage fees. For the years 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. Prior to April 1, 2002, we received 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 year ended December 31, 2002 and the four months ended December 31, 2001, we received $6.8 million and $8.2 million in platform revenue related to this agreement. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our Prince TLP to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

Production fields. Through 2000 we had agreed to sell substantially all of our oil and natural gas production to El Paso 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 year ended December 31, 2000, oil and natural gas sales related to this agreement totaled approximately $15.7 million. Beginning in the fourth quarter of 2000, we began selling our oil and natural gas directly to third parties and our oil and natural gas sales related to El Paso Merchant Energy North America Company were approximately $9.8 million and $5.7 million for years ended December 31, 2002 and 2001.

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, 2002 and the four months ended

December 31, 2001, we recorded approximately $1.0 million and $0.7 million in revenues related to our overriding royalty interest in the Prince Field. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our 9 percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

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, 2002, 2001 and 2000, we received approximately $6.8 million, $8.3 million and $4.9 million from El Paso Merchant Energy North America Company. For the years ended December 31, 2002, 2001 and 2000, we received approximately $4.5 million, $4.2 million and $4.3 million from El Paso Production Company. For the years ended December 31, 2002, 2001 and 2000, we received approximately $0.1 million, $0.2 million and $0.2 million from Southern Natural Gas Company.

HIOS. In October 2001, HIOS became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings. HIOS is a natural gas transmission system that has entered into interruptible transportation agreements at a non-discounted rate of $0.1244. For the year ended December 31, 2002 and approximately three months ended December 31, 2001, we received $1.4 million and $0.8 million from El Paso Merchant Energy. For the year ended December 31, 2002, we received $0.6 million from El Paso Production Company.

Texas NGL assets. In connection with our acquisition of the San Juan assets in November, 2002, we entered into a 10-year transportation agreement with El Paso Field Services. Pursuant to this agreement, beginning January 1, 2003, we receive a fee of $1.5 million per year for transportation on our NGL pipeline which extends from Corpus Christi to near Houston. In addition, we provide transportation, fractionation, storage and terminaling services to El Paso Field Services, as well as to various third parties, typically under agreements of one year term or less. We received approximately $0.3 million in revenues from El Paso Field Services for the year ended December 31, 2002.

Other. In addition to the revenues discussed above, we received $2.6 million from El Paso Merchant North America and $3.3 million from El Paso Field Services during 2002 for additional gathering and processing services.

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

Expenses paid to related parties

Cost of natural gas. Our cost of natural gas paid to related parties increased in 2002 as a result of our EPN Holding transaction in which we acquired contracts with affiliates of our general partner. For the year ended December 31, 2002, our EPN Holding assets had cost of natural gas expenses of $0.3 million for the Waha facility from El Paso Merchant Energy North America Company and $0.4 million from El Paso Field Services relating to the EPGT gathering system. EPIA's purchases of natural gas include transactions with affiliates of our general partner. For the years ended December 31, 2002, 2001 and 2000, we had natural gas purchases of approximately $18.9 million, $28.2 million and $14.4 million from El Paso Merchant Energy North America Company, $2.3 million, $6.4 million and $2.2 million from El Paso Production Company and $0.2 million, $0.2 million and $0.1 million from Southern Natural Gas Company. We also receive lease and throughput fees from El Paso Field Services for Hattiesburg and Anse La Butte. For the year ended December 31, 2002 we received $0.5 million from El Paso Field Services related to these fees.

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 general and administrative services agreement between subsidiaries of El Paso Corporation and us, a fee of approximately $0.8 million per month was charged to our general partner, and accordingly, to us, which is intended to approximate the amount of resources allocated by El Paso Corporation and its affiliates in providing various operational, financial, accounting and administrative services on behalf of our general partner and us. In April 2002, in connection with our acquisition of EPN Holding assets, our general and administrative services agreement was extended to December 31, 2005, and the fee increased to approximately $1.6 million per month. In November 2002, as a result of the San Juan assets acquisition, the monthly fee under our general and administrative services agreement increased by $1.3 million, bringing our total monthly fee to $2.9 million. We believe this fee approximates the actual costs incurred. 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.

As we became operator of additional facilities or systems, 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:

	2002	2001	2000
	(IN THOUSANDS)		
Basic management fee	$18,092	$ 9,300	$ 9,300
Operating fees(1)	38,422	19,821	10,388
Insurance and other costs	3,486	4,066	2,577
	$60,000	$33,187	$22,265

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(1) Operating fees increased from 2001 to 2002 due to the acquisition of the San Juan assets and EPN Holding assets. The increase from 2000 to 2001 is due to the EPN Texas asset acquisition.

Poseidon charges were for transportation services related to transporting production from our Garden Banks Block 72 and 117 leases.

Cost Reimbursements. In connection with becoming the operator of Poseidon, we entered into an operating agreement in January 2001. For the year ended December 31, 2000, we charged Manta Ray Offshore a management fee pursuant to its management and operations agreements. 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 was a fixed monthly amount covering normal operating activities that was approved by each subsidiary's management committee and was based on historical operating expenses. We recorded these as a reduction to our operation and maintenance expense. To the extent our costs were more than the monthly reimbursement, our operating expenses were higher, and to the extent our costs were lower than the monthly reimbursement, our operating expense were lower. In addition, due to the timing of actual costs, we recognized fluctuations in our results of operations throughout the years.

Acquisitions

We have purchased assets from related parties. See Note 2 for a discussion of these asset acquisitions.

Other Matters

In addition to the related party transactions discussed above, pursuant to the terms of many of the purchase and sale agreements we have entered into with various entities controlled directly or indirectly by El Paso Corporation, we have been indemnified for potential future liabilities, expenses and capital requirements above a negotiated threshold. Specifically, an indirect subsidiary of El Paso Corporation has agreed to indemnify us for specific litigation matters to the extent the ultimate resolutions of these matters result in judgments against us. For a further discussion of these matters see Note 10, Commitments and Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We do not believe these thresholds will be exceeded. We have made no such claims for reimbursement to date and none are contemplated to be made at this time.

We have also entered into contracts with El Paso Merchant Energy for transportation and storage. El Paso Corporation announced on November 8, 2002 its intention to exit the energy trading business which is party to these contracts. El Paso Merchant Energy North America Company could sell or transfer to third parties the natural gas transportation and storage agreements they have with us, or El Paso Merchant Energy North America Company could request a cancellation of the transportation and storage agreements. In 2002, these agreements represented revenue of approximately $33 million. At present, El Paso Merchant Energy North America Company continues to fully utilize these agreements.

We have also entered into capital contribution arrangements with regulated pipelines owned by El Paso Corporation in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. Regulated pipelines often contribute capital toward the construction costs of gathering facilities owned by others which are connected to their pipelines. We have agreements with ANR Pipeline Company and Tennessee Gas Pipeline Company under which we will receive a total of approximately $12 million of capital toward the construction of gathering pipelines to the Marco Polo and Medusa discoveries, payable over the next eighteen months. We will account for these payments as a reduction in property, plant and equipment. As of December 31, 2002, we received approximately $2 million from ANR Pipeline Company as contributions in aid of construction of the Marco Polo pipeline.

At December 31, 2002 and 2001, our accounts receivable due from related parties was $83.8 million and $23.0 million. At December 31, 2002 and 2001, our accounts payable due to related parties was $86.1 million and $10.1 million.

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

	DECEMBER 31, 2002	DECEMBER 31, 2001
	(IN THOUSANDS)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$30,512	$ 1,057
El Paso Production Company	4,346	2,559
Tennessee Gas Pipeline Company	930	1,062
El Paso Field Services(1)	36,071	14,448
El Paso Natural Gas Company	1,033	--
ANR Pipeline Company	671	3,663
Other	627	222
	74,190	23,011
Unconsolidated Subsidiaries		
Poseidon Oil Pipeline Company	--	2
Deepwater Gateway	9,636	--
	9,636	2
Total	$83,826	$23,013

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(1) The December 2002 receivable balance includes approximately $15 million of natural gas imbalances relating to our EPN Holding acquisition.

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

	DECEMBER 31, 2002	DECEMBER 31, 2001
	(IN THOUSANDS)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 8,871	$ 7
El Paso Production Company	14,518	--
Tennessee Gas Pipeline Company	1,319	595
El Paso Field Services(1)	55,648	8,283
El Paso Natural Gas Company	1,475	
El Paso Corporation	4,181	560
Other	132	291
	86,144	9,736
Unconsolidated Subsidiaries		
Poseidon Oil Pipeline Company	--	332
Total	$86,144	$10,068

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(1) The December 2002 payable balance includes approximately $19 million of working capital adjustments relating to our EPN Holding acquisition due to El Paso Field Services; and approximately $22 million of natural gas imbalances relating to our EPN Holding acquisition.

In connection with the San Juan assets acquisition in November 2002, we acquired a 50 percent interest in Coyote Gas Treating LLC. As part of this transaction we assumed a note receivable due from our unconsolidated affiliate, Coyote, for $17.1 million.

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

	DECEMBER 31, 2002	DECEMBER 31, 2001
	(IN THOUSANDS)	
Accounts receivable, net	$ 8,403	$ 7,745
Other noncurrent assets	1,960	10,362
	$10,363	$18,107

10. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Grynberg. In 1997, we were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties Qui Tam Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding.

Will Price (formerly Quinque). 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. Quinque has been dropped as a plaintiff and Will Price has been added. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The plaintiff in this case seeks certification of a nationwide class of gas working interest owners and gas royalty owners to recover royalties that the plaintiff contends these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs motion for class certification has been argued and we are awaiting a ruling.

Our Argo L.L.C. subsidiary received a claim from its contractor related to the Prince TLP. The contractor received a request for additional payments from its subcontractor as a result of variation orders and was seeking to pass these costs along to Argo. After negotiations, the contractor, the subcontractor and Argo agreed upon a settlement in July 2002. This settlement did not have a material adverse effect on our financial position, results of operations or cash flow.

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

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process gas in areas of western Texas related to an asset now owned by EPN Holding. In May 2001, the court ruled in favor of Leapartners and entered a judgment against El Paso Field Services of approximately $10 million. El Paso Field Services has filed an appeal with the Eighth Court of Appeals in El Paso, Texas. Briefs have been filed and oral arguments were heard in November 2002. Review by the Court of Appeals is expected in early 2003.

Also, EPGT Texas Pipeline L.P., now owned by EPN Holding, is involved in litigation with the City of Edinburg concerning the City's claim that EPGT Texas was required to pay pipeline franchise fees under a contract the City had with Rio Grande Valley Gas Company, which was previously owned by EPGT Texas and is now owned by Southern Union Gas Company. An adverse judgment against Southern Union and EPGT Texas was rendered in Hidalgo County State District court in December 1998 and found a breach of contract, and held both EPGT Texas and Southern Union jointly and severally liable to the City for approximately $4.7 million. The judgment relies on the single business enterprise doctrine to impose contractual obligations on EPGT Texas and Southern Union's entities that were not parties to the contract with the City. EPGT Texas has appealed this case to the Texas Supreme Court seeking reversal of the judgment rendered against EPGT Texas. The City seeks a remand to the trial court of its claim of tortious interference against EPGT Texas. Briefs have been filed and oral arguments were held in November 2002, and we are awaiting a decision.

In December 2000, a 30-inch natural gas pipeline jointly owned by El Paso Energy Intrastate, now owned by EPN Holding, and Houston Pipe Line Company LP ruptured in Mont Belvieu, Texas, near Baytown, resulting in substantial property damage and minor physical injury. El Paso Energy Intrastate is the operator of the pipeline. In December 2000 a lawsuit was filed in the state district court in Chambers County, Texas by eight plaintiffs, including two homeowners' insurers. The suits seek recovery for physical pain and suffering, mental anguish, physical impairment, medical expenses, and property damage. Houston Pipe Line Company has been added as an additional defendant. In accordance with the terms of the operating agreement, El Paso Energy Intrastate has agreed to assume the defense of and to indemnify Houston Pipe Line Company. In September 2002, an agreement was reached to settle the claims of two plaintiffs (including one of the insurers). The discovery phase of the lawsuit is proceeding and trial is expected in early 2003.

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

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

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we will establish the necessary accruals. As of December 31, 2002, we had no reserves for our legal matters.

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

Environmental

Each of our operating segments is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2002, we had a reserve of approximately $21 million for remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased as part of the San Juan assets acquisition up to the purchase price of $766 million. We will only be indemnified for unknown liabilities for up to three years from the purchase date. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased. Also, we expect to make capital expenditures for environmental matters of approximately $10 million in the aggregate for the years 2003 through 2007, primarily to comply with clean air regulations.

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

Rates and Regulatory Matters

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

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

Negotiated Rate NOI. In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. The FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost of service based rate) continues to safeguard against a pipeline exercising market power, as well as other issues related to negotiated rate programs. At this time, we cannot predict the outcome of this NOI.

Cash Management NOPR. In August 2002, the FERC issued a NOPR requiring that all cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth: the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to, these arrangements. Finally, the NOPR proposes that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity must maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent must maintain investment grade credit ratings. In August 2002 comments were filed. The FERC held a public conference in September 2002, to discuss the issues raised in the comments. Representatives of companies from the gas and electric industries participated on a panel and uniformly agreed that the proposed regulations should be revised substantially and that the proposed capital balance and investment grade credit rating requirements would be excessive. At this time, we cannot predict the outcome of this NOPR.

Also in August 2002, FERC's Chief Accountant issued an Accounting Release, which was effective immediately, providing guidance on how companies should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. However, the Accounting Release did not address the proposed requirements that the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent have investment grade credit ratings. Requests for rehearing were filed in August 2002. The FERC has not yet acted on the rehearing requests.

If the cash management NOPR is adopted by the FERC, our HIOS and Petal interstate facilities will no longer be permitted to participate in a money pool or cash management program. As a result, more frequent distributions or equity contributions may be needed in anticipation of monthly cash flow requirements for those interstate facilities. Also, separate credit facilities and resources may be required to support the capital and day-to-day activities for the interstate facilities separate from other of our subsidiaries and our primary bank accounts.

Emergency Reconstruction of Interstate Natural Gas Facilities NOPR. In April 2002, FERC and the Department of Transportation, Office of Pipeline Safety convened a technical conference to discuss how to clarify, expedite, and streamline permitting and approvals for interstate pipeline reconstruction in the event of disaster, whether natural or otherwise. In January 2003, FERC issued a NOPR proposing to (1) expand the scope of construction activities authorized under a pipeline's blanket certificate to allow replacement of mainline facilities; (2) authorize a pipeline to commence reconstruction of the affected system without a waiting period; and (3) authorize automatic approval of construction that would be above the normal cost ceiling. Comments on the NOPR were due on February 27, 2003. At this time we cannot predict the outcome of this rulemaking.

Pipeline Safety Notice of Proposed Rulemaking. On January 28, 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. We intend to submit comments on the NOPR, which are due on March 31, 2003. At this time, we cannot predict the outcome of this rulemaking.

Other Regulatory Matters. Our HIOS system is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a separate FERC approved tariff that governs its operations, terms and conditions of service, and rates. We timely filed a required rate case for our HIOS system on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee, and changes to depreciation rates and negative salvage amortization. HIOS' filing reflects zero rate base; therefore, a management fee in place of a return on rate base has been requested. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. The FERC has scheduled a hearing on this matter commencing November 17, 2003.

In June 2002, Petal Gas Storage, which is also subject to the FERC's jurisdiction filed with the FERC a certificate application to add additional gas storage capacity to Petal's storage system. The filing included a new storage cavern with a working gas capacity of 5 Bcf, the conversion and enlargement of an existing subsurface brine storage cavern to a gas storage cavern with a working capacity of 3 Bcf and related surface facilities, natural gas, water and brine transmission lines. In February 2003, the FERC approved the facilities proposed by Petal.

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

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

In December 2002, EPGT Texas requested FERC approval of market-based rates for interstate gas storage services performed at its Wilson storage facility. The filing was in compliance with a requirement to rejustify its existing rates or request new rates by December 20, 2002. The requested market-based rates are currently subject to refund. Falcon also intervened in this filing, complaining that market-based rates should be denied because of their complaint about access on the EPGT pipeline for third party imbalance services. We filed a response stating that their complaint is not relevant to the rate case, that a severance of this issue has been requested in the EPGT pipeline rate case, and requesting a dismissal of their intervention. This matter is pending before the FERC.

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

Operating Lease

We have long-term operating lease commitments associated with the Wilson natural gas storage facility we acquired in April 2002 in connection with the EPN Holding acquisition. The term of the natural gas storage facility and base gas leases runs through January 2008, and subject to certain conditions, has one or more optional renewal periods of five years each at fair market rent at the time of renewal.

The future minimum lease payments under these operating lease commitments as of December 31, 2002 are as follows (in thousands):

2003	$ 5,219
2004	5,219
2005	5,219
2006	5,219
2007	5,219
Remainder	2,609
Total minimum lease payments	$28,704

Rental expense under operating leases was approximately $3.9 million for the year ended December 31, 2002. We did not have any operating leases prior to our acquisition of the EPN Holding assets.

Guarantees

We conduct our business through our wholly-owned subsidiaries, joint ventures and other ownership arrangements to construct, operate and finance the development of our onshore and offshore midstream energy businesses. Third parties routinely require us to provide performance and financial guarantees to support the obligations of our subsidiaries under contracts entered into in connection with our business. The events and circumstances that may require us, on behalf of our subsidiaries, to perform under these guarantees include nonperformance by our joint ventures and other affiliates of services, such as gathering, transportation, processing and storage services, and nonpayment of contractual obligations.

As of December 31, 2002, we had approximately $132.8 million of performance guarantees in connection with the activities of our joint ventures and other affiliates. Such contingent obligations are not recorded in our consolidated financial statements unless they become payable. The most significant of our performance guarantee commitments is related to the construction of the Marco Polo TLP facility. We have guaranteed the payment of approximately $51 million as of December 31, 2002, under the turnkey construction contract between Deepwater Gateway and the construction contractor. We are obligated to perform under this guarantee should Deepwater Gateway fail to satisfy its obligations by drawing under its $155 million project finance loan or Deepwater Gateway's joint venture partners fail to perform under their joint venture agreement. Our commitment under this guarantee is scheduled to expire in 2003.

As discussed in Note 6, we are also obligated under an agreement with certain lenders to make payments on behalf of Deepwater Gateway for all distributions we or any of our subsidiaries receive up to $22.5 million, if Deepwater Gateway defaults on its payment obligations under their project finance loan. Neither we, nor any of our subsidiaries have received any distributions from Deepwater Gateway as of December 31, 2002.

Other Matters

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

11. ACCOUNTING FOR HEDGING ACTIVITIES

A majority of our commodity purchases and sales, which relate to purchases and sales of natural gas associated with our EPIA pipeline and San Juan assets, sales of liquids associated with our interest in the Indian Basin processing plant and sales of oil and natural gas associated with our production operations, 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 2002 and 2001, we entered into cash flow hedges.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of $3.525 per MMBtu and pay a floating price based on the San Juan index. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative under mark-to-market accounting since it did not qualify for hedge accounting under SFAS 133. Through the acquisition date, we recognized a $0.4 million gain in the margin of our Natural gas pipelines and plants segment. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under SFAS No. 133. As of December 31, 2002, the fair value of this cash flow hedge was a liability of $4.8 million. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction. We estimate the entire amount will be reclassified from accumulated other comprehensive income to earnings over the next 12 months. In connection with our San Juan asset purchase, we also acquired the outstanding risk management positions at the Chaco plant. The value of these NGL and natural gas positions was a $0.5 million liability at the acquisition date and this amount was included in the working capital adjustments to the purchase price. These positions expired in December 2002.

At December 31, 2002, in connection with our EPIA operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2001 and 2002 to offset the risk of increasing natural gas prices. As of December 31, 2002, the fair value of these cash flow hedges was an asset of approximately $86 thousand. For the twelve months ended December 31, 2002, the majority of these cash flow hedges expired and we reclassified a loss of $1.4 million from accumulated other comprehensive income to earnings. We estimate the entire amount will be reclassified from accumulated other comprehensive income to earnings over the next six months. As of December 31, 2001, the fair value of these cash flow hedges was a liability of $1.3 million. During the year ended December 31, 2001, we reclassified a gain of $400 thousand from other comprehensive income to earnings. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

Beginning in April 2002, in connection with our EPN Holding acquisition, we had swaps in place for our interest in the Indian Basin processing plant to hedge the price received for the sale of natural gas liquids. All of these hedges expired by December 31, 2002, and we recorded a loss of $163 thousand during 2002 for these cash flow hedges. We did not have any ineffectiveness in our hedging relationship since all sale prices were based on the same index as the hedge transaction.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of its $150 million variable rate revolving credit facility at 3.49% over the life of the swap. Poseidon, under its credit facility, pays an additional 150 basis points over the LIBOR rate resulting in an effective interest rate at 4.99% on the hedged notional amount. As of December 31, 2002, the fair value of its interest rate swap was a liability of $1.4 million resulting in accumulated other comprehensive loss of $1.4 million. We included our 36 percent share of this liability of $0.5 million as a reduction of our investment in Poseidon and as loss in accumulated other comprehensive income which will be reclassified to earnings proportionately over the next twelve months. Additionally, we have recognized in income our 36 percent share of Poseidon's realized loss of $1.2 million for the twelve months ended December 31, 2002, or $0.4 million, through our earnings from unconsolidated affiliates.

Our counterparties for EPIA and Indian Basin hedging activities are El Paso Merchant Energy and El Paso Field Services, affiliates of our general partner. We do not require collateral and do not anticipate non-performance by our counterparties. The counterparty for Poseidon's hedging activity is Credit Lyonnais. Poseidon does not require collateral and does not anticipate non-performance by the counterparty. The counterparty of our San Juan hedging activity is J. Aron and Company, a subsidiary of Goldman Sachs. We do not require collateral and do not anticipate non-performance by the counterparty.

12. SUPPLEMENTAL DISCLOSURES TO THE STATEMENTS OF CASH FLOWS

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

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Interest	$73,598	$41,020	$46,768

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

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN THOUSANDS)		
Acquisition of San Juan assets			
Issuance of Series C units	$350,000	$ --	$ --
Investment in processing agreement classified to property, plant and equipment	114,412	--	--
Acquisition of EPN Holding assets			
Issuance of common units	6,000	--	--
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)

13. MAJOR CUSTOMERS

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

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
El Paso Merchant Energy North America Company	21%	--	--
El Paso Field Services	18%	16%	--
Alabama Gas Corporation	--	14%	20%
Shell Offshore	--	--	13%
Kerr-McGee Corporation	--	--	11%

The 2002 percentage increase in revenue from El Paso Merchant Energy North America Company and El Paso Field Services is primarily due to our EPN Holding and San Juan asset acquisitions completed in 2002. 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:

Each of our segments are business units that offer different services and products that are managed separately since each segment requires different technology and marketing strategies. We have 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. We record intersegment revenues at rates that approximate market. 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 income taxes (EBIT) instead of operating income. We define EBIT as operating income, adjusted for several items, including: earnings from unconsolidated affiliates, minority interest of consolidated subsidiaries, gains and losses on sales of assets and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense, income tax benefit and discontinued operations. We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our business and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating cash flow.

In addition to EBIT, we also measure segment performance using performance cash flows, or an asset's ability to generate cash flow. We believe our presentation of performance cash flows provides additional information which may be used to determine our ability to pay distributions, service our debt obligations, and grow the business. Our management uses performance cash flows, in addition to other information, to evaluate the performance of our assets, determine how resources will be allocated, and develop strategic plans. These measures are used as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to GAAP measures as indicators of our operating performance or as measures of our liquidity. Performance cash flows may not be a comparable measurement among different companies.

Our operating results and financial position reflect the acquisitions of the San Juan assets in November 2002, the EPN Holding assets in April 2002, the Chaco plant and the remaining 50 percent interest we did not already own in Deepwater Holdings in October 2001, EPN Texas in February 2001, the Petal and Hattiesburg natural gas storage facilities in August 2000 and EPIA in March 2000. The acquisitions were accounted for as purchases and therefore operating results of these acquired entities are included prospectively from the purchase date. 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
	(IN THOUSANDS)					
FOR THE YEAR ENDED DECEMBER 31, 2002						
Revenue from external customers..................	$ 357,581	$ 48,173	$ 28,602	$ 16,672	$ 16,890	$ 467,918
Intersegment revenue..........	227	--	--	9,283	(9,510)	--
Depreciation, depletion and amortization...............	44,479	6,481	8,503	4,205	8,458	72,126
Operating income (loss).......	121,568	21,059	8,126	18,749	(8,219)	161,283
Earnings (loss) from unconsolidated investments................	194	13,445	--	--	--	13,639
EBIT.........................	121,371	34,507	8,126	18,863	(6,821)	176,046
Performance cash flows........	167,245	43,347	16,629	29,224	10,427	266,872
Assets.......................	2,279,955	265,900	320,662	140,758	123,621	3,130,896
FOR THE YEAR ENDED DECEMBER 31, 2001						
Revenue from external customers..................	$ 100,683	$ 32,327	$ 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).......	22,349	20,235	7,584	20,754	(1,036)	69,886
Earnings (loss) from unconsolidated investments................	(9,761)	18,210	--	--	--	8,449
EBIT.........................	27,413	38,445	7,604	20,122	2,010	95,594
Performance cash flows........	52,152	47,560	13,209	30,783	17,636	161,340
Assets.......................	563,698	195,839	226,991	115,364	69,968	1,171,860
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..........................	36,987	21,322	2,193	22,491	(15,729)	67,264
Performance cash flows........	55,106	28,527	4,061	24,686	(5,371)	107,009
Assets........................	345,309	65,734	176,420	111,810	48,706	747,979

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(1) Represents predominately our oil and natural gas production activities as well as intersegment eliminations. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

RECONCILIATION OF PERFORMANCE CASH FLOWS BY SEGMENT

NATURAL GAS NATURAL PIPELINES & OIL AND GAS PLATFORM PLANTS NGL LOGISTICS STORAGE SERVICES OTHER TOTAL ----------- ------------- ------- -------- ------- -------- (IN THOUSANDS) YEAR ENDED DECEMBER 31, 2002 Net income........................ $ 97,688 Plus: Interest and debt expense(1)...................... 83,494 Less: Income from discontinued operations...................... 5,136 EBIT.............................. $121,371 $34,507 $ 8,126 $18,863 $(6,821) 176,046 Plus: Depreciation, depletion and amortization.................... 44,479 6,481 8,503 4,205 8,458 72,126 Cash distributions from unconsolidated affiliates..... 2,000 15,804 -- -- -- 17,804 Net cash payment received from El Paso Corporation.............. -- -- -- -- 7,745 7,745 Discontinued operations of Prince facilities................... -- -- -- 6,156 1,045 7,201 Less: Earnings from unconsolidated affiliates...................... 194 13,445 -- -- -- 13,639 Noncash hedge gain........... 411 -- -- -- -- 411 -------- ------- ------- ------- ------- -------- Performance cash flows(2).......... $167,245 $43,347 $16,629 $29,224 $10,427 $266,872 ======== ======= ======= ======= ======= ======== YEAR ENDED DECEMBER 31, 2001 Net income........................ $ 55,149 Plus: Interest and debt expense(1)...................... 41,542 Less: Income from discontinued operations...................... 1,097 EBIT.............................. $ 27,413 $38,445 $ 7,604 $20,122 $ 2,010 95,594 Plus: Depreciation, depletion and amortization.................... 12,378 5,113 5,605 4,154 7,528 34,778 Asset impairment charge......... 3,921 -- -- -- -- 3,921 Cash distributions from unconsolidated affiliates..... 12,850 22,212 -- -- -- 35,062 Net cash payment received from El Paso Corporation.............. -- -- -- -- 7,426 7,426 Discontinued operations of Prince facilities................... -- -- -- 5,889 672 6,561 Loss on sale of Gulf of Mexico assets....................... 7,793 -- -- 4,058 -- 11,851 Less: Earnings (loss) from unconsolidated affiliates........ (9,761) 18,210 -- -- -- 8,449 Non-cash earnings related to future payments from El Paso Corporation...................

21,964 -- -- 3,440 -- 25,404 -----
--- ------- ------- ------- ------
- -------- Performance cash
flows(2).......... $ 52,152
$47,560 $13,209 $30,783 $17,636
$161,340 ======== ======= =======
======= ======= ========

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(1) We finance our activities at the consolidated level and therefore we do not allocate interest and debt expense among our segments.

(2) Performance cash flows is determined by taking earnings before interest and income taxes and adding or subtracting, as appropriate, cash distributions from unconsolidated affiliates; depreciation, depletion and amortization; earnings from unconsolidated affiliates; gains and losses on asset sales; and other nonrecurring items.

RECONCILIATION OF PERFORMANCE CASH FLOWS BY SEGMENT

	NATURAL GAS PIPELINES & PLANTS	OIL AND NGL LOGISTICS	NATURAL GAS STORAGE	PLATFORM SERVICES	OTHER	TOTAL
	(IN THOUSANDS)					
YEAR ENDED DECEMBER 31, 2000						
Net income						$ 20,497
Plus: Interest and debt expense(1)						46,820
Less: Income from discontinued operations						(252)
Income tax benefit						305
EBIT	$36,987	$21,322	$2,193	$22,491	$(15,729)	67,264
Plus: Depreciation, depletion and amortization	8,062	1,391	1,868	4,445	11,977	27,743
Cash distributions from unconsolidated affiliates	20,428	13,532	--	--	--	33,960
Insurance proceeds	--	5,000	--	--	--	5,000
Less: Earnings from unconsolidated affiliates	10,213	12,718	--	--	--	22,931
Litigation resolution	--	--	--	2,250	--	2,250
Hedging activities	--	--	--	--	1,619	1,619
Gain on sale of assets	158	--	--	--	--	158
Performance cash flows(2)	$55,106	$28,527	$4,061	$24,686	$ (5,371)	$107,009

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(1) We finance our activities at the consolidated level and therefore we do not allocate interest and debt expense among our segments.

(2) Performance cash flows is determined by taking earnings before interest and income taxes and adding or subtracting, as appropriate, cash distributions from unconsolidated affiliates; depreciation, depletion and amortization; earnings from unconsolidated affiliates; gains and losses on asset sales; and other nonrecurring items.

15. GUARANTOR FINANCIAL INFORMATION

In May 2001, we purchased our general partner's 1.01 percent non-managing interest owned in twelve of our subsidiaries for $8 million. As a result of this acquisition, all our subsidiaries, but not our equity investees, are wholly owned by us. As of December 31, 2002, our revolving credit facility, EPN Holding term credit facility, senior secured term loan and senior secured acquisition term loan are guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries, and are collateralized by our general and administrative services agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, as of December 31, 2002, all of our senior subordinated notes are jointly, severably, fully and unconditionally guaranteed by us and all our subsidiaries excluding our unrestricted subsidiaries. As of December 31, 2001, our revolving credit facility was guaranteed by us and each of our subsidiaries (excluding Argo, L.L.C. and Argo I, L.L.C. subsidiaries) and was collateralized by our general and administrative services agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, all of our senior subordinated notes were guaranteed by all of our subsidiaries except Argo and Argo I. The consolidating eliminations column on our balance sheets eliminate our investment in consolidating subsidiaries, intercompany payables and receivables and other transactions between subsidiaries.

Non-guarantor subsidiaries for the year ended December 31, 2002, consisted of Argo and Argo I for the quarter ended March 31, 2002, our EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002, and our unrestricted subsidiaries for the quarter ended December 31, 2002. Non-guarantor subsidiaries for all other periods consisted of Argo and Argo I which owned the Prince TLP. As a result of our disposal of the Prince TLP and our related overriding royalty interest in April 2002, the results of operations and net book value of these assets are reflected as discontinued operations in our statements of income and assets held for sale in our balance sheets and Argo and Argo I became guarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2002

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Operating revenues				
Natural gas pipelines and plants				
Natural gas sales	$ --	$ 30,778	$ 54,223	$ 85,001
NGL sales	--	15,050	17,928	32,978
Gathering and transportation	--	71,560	122,776	194,336
Processing	--	5,316	39,950	45,266
	--	122,704	234,877	357,581
Oil and NGL logistics				
Oil sales	--	--	10,636	10,636
Oil transportation	--	--	8,364	8,364
Fractionation	--	--	26,356	26,356
NGL storage	--	--	2,817	2,817
	--	--	48,173	48,173
Platform services	--	--	16,672	16,672
Natural gas storage	--	2,699	25,903	28,602
Other -- oil and natural gas production	--	--	16,890	16,890
	--	125,403	342,515	467,918
Operating expenses				
Cost of natural gas	--	39,280	80,067	119,347
Operations and maintenance	6,056	27,701	81,405	115,162
Depreciation, depletion and amortization	274	10,729	61,123	72,126
	6,330	77,710	222,595	306,635
Operating income (loss)	(6,330)	47,693	119,920	161,283
Other income (loss)				
Earnings from unconsolidated affiliates	--	--	13,639	13,639
Net loss on sales of assets	--	--	(473)	(473)
Minority interest	--	60	--	60
Other income	1,471	5	61	1,537
Interest and debt income (expense)	37,696	(22,048)	(99,142)	(83,494)
Income from continuing operations	32,837	25,710	34,005	92,552
Income from discontinued operations	--	4,004	1,132	5,136
Net income	$32,837	$ 29,714	$ 35,137	$ 97,688

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(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2001

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Operating revenues				
Natural gas pipelines and plants				
Natural gas sales	$ --	$ --	$ 59,701	$ 59,701
Gathering and transportation	--	--	33,849	33,849
Processing	--	--	7,133	7,133
	--	--	100,683	100,683
Oil and NGL logistics				
Oil transportation	--	--	7,082	7,082
Fractionation	--	--	25,245	25,245
	--	--	32,327	32,327
Platform services	--	--	15,385	15,385
Natural gas storage	--	--	19,373	19,373
Other -- oil and natural gas production	--	--	25,638	25,638
	--	--	193,406	193,406
Operating expenses				
Cost of natural gas	--	--	51,542	51,542
Operations and maintenance	(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	(123)	--	70,009	69,886
Other income				
Earnings from unconsolidated affiliates	--	--	8,449	8,449
Net loss on sales of assets	(10,941)	--	(426)	(11,367)
Minority interest	--	--	(100)	(100)
Other income	28,492	--	234	28,726
Interest and debt expense	15,328	--	(56,870)	(41,542)
Income from continuing operations	32,756	--	21,296	54,052
Income from discontinued operations	--	1,308	(211)	1,097
Net income (loss)	$ 32,756	$1,308	$ 21,085	$ 55,149

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2000

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Operating revenues				
Natural gas pipelines and plants				
Natural gas sales	$ --	$ --	$ 34,531	$ 34,531
Gathering and transportation	--	--	28,968	28,968
	--	--	63,499	63,499
Oil and NGL logistics				
Oil transportation	--	--	8,307	8,307
	--	--	8,307	8,307
Platform services	--	--	13,875	13,875
Natural gas storage	--	--	6,182	6,182
Other -- oil and natural gas production	--	--	20,552	20,552
	--	--	112,415	112,415
Operating expenses				
Cost of natural gas	--	--	28,160	28,160
Operation and maintenance	(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
Minority interest	--	--	(95)	(95)
Other income	311	--	2,066	2,377
Interest and debt expense	(70)	--	(46,750)	(46,820)
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

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATING BALANCE SHEETS
DECEMBER 31, 2002

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	Guarantor SUBSIDIARIES	Consolidating ELIMINATIONS	Consolidated TOTAL
	(In thousands)				
Current assets					
Cash and cash equivalents........	$ 20,777	$ --	$ 15,322	$ --	$ 36,099
Accounts receivable, net					
Trade.........................	--	74	139,445	--	139,519
Affiliates....................	709,230	3,055	67,513	(695,972)	83,826
Affiliated note receivable.......	--	--	17,100	--	17,100
Other current assets.............	1,118	--	2,333	--	3,451
Total current assets.....	731,125	3,129	241,713	(695,972)	279,995
Property, plant and equipment, net..............................	6,716	454	2,717,768	--	2,724,938
Intangible assets..................	--	--	3,970	--	3,970
Investments in unconsolidated affiliates......................	--	5,197	73,654	--	78,851
Investments in consolidated affiliates......................	1,787,767	--	693	(1,788,460)	--
Other noncurrent assets............	205,262	--	7,879	(169,999)	43,142
Total assets............	$2,730,870	$ 8,780	$3,045,677	$(2,654,431)	$3,130,896
Current liabilities					
Accounts payable					
Trade.........................	$ --	$ 302	$ 126,422	$ --	$ 126,724
Affiliates....................	18,867	2,982	760,267	(695,972)	86,144
Accrued interest.................	14,221	--	807	--	15,028
Current maturities of senior secured term loan.............	--	--	5,000	--	5,000
Other current liabilities........	1,645	5	19,545	--	21,195
Total current liabilities...........	34,733	3,289	912,041	(695,972)	254,091
Revolving credit facility..........	491,000	--	--	--	491,000
Senior secured term loans, less current maturities..............	397,500	--	155,000	--	552,500
Long-term debt.....................					

857,786 -- -- -- 857,786 Other noncurrent liabilities....... (1) -- 193,725 (169,999) 23,725 Minority interest................. -- 1,942 -- -- 1,942 Partners' capital................. 949,852 3,549 1,784,911 (1,788,460) 949,852 ---------- - ------- ---------- ----------- - --------- Total liabilities and partners' capital...... $2,730,870 $ 8,780 $3,045,677 $(2,654,431) $3,130,896 ========== ======== ========== =========== ==========

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(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2001

(IN THOUSANDS)	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATING ELIMINATIONS	CONSOLIDATED TOTAL
Current assets					
Cash and cash equivalents.......	$ 7,406	$ 2,571	$ 3,107	$ --	$ 13,084
Accounts receivable, net					
Trade.......................	--	191	32,971	--	33,162
Affiliates..................	970,935	2,125	2,303	(952,350)	23,013
Other current assets...........	2,375	264	(2,082)	--	557
Total current assets....	980,716	5,151	36,299	(952,350)	69,816
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............	$1,231,824	$158,974	$1,186,780	$(1,220,158)	$1,357,420
Current liabilities					
Accounts payable					
Trade.......................	$ 587	$ 3,859	$ 10,541	$ --	$ 14,987
Affiliates..................	2	13,563	948,853	(952,350)	10,068
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..........	6,098	37,125	963,742	(952,350)	54,615
Revolving credit facility.........	300,000	--	--	--	300,000
Limited recourse term loan, less current maturities..............	--	76,000	--	--	76,000
Long-term debt....................					

425,000 -- -- -- 425,000 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..... $1,231,824 $158,974 $1,186,780 $(1,220,158) $1,357,420 ========== ======== ========== =========== ==========

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOW
YEAR ENDED DECEMBER 31, 2002

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED TOTAL
	(IN THOUSANDS)			
Cash flows from operating activities				
Net income	$ 32,837	$ 29,714	$ 35,137	$ 97,688
Less income from discontinued operations	--	4,004	1,132	5,136
Income from continuing operations	32,837	25,710	34,005	92,552
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation, depletion and amortization	274	10,730	61,122	72,126
Distributed earnings of unconsolidated affiliates				
Earnings from unconsolidated affiliates	--	--	(13,639)	(13,639)
Distributions from unconsolidated affiliates	--	--	17,804	17,804
Net loss on sale of assets	--	--	473	473
Other noncash items	4,504	(3,240)	2,992	4,256
Working capital changes, net of acquisitions and non-cash transactions	16,810	(15,873)	(3,753)	(2,816)
Net cash provided by continuing operations	54,425	17,327	99,004	170,756
Net cash provided by discontinued operations	--	4,631	613	5,244
Net cash provided by operating activities	54,425	21,958	99,617	176,000
Cash flows from investing activities				
Development expenditures for oil and natural gas properties	--	--	(1,682)	(1,682)
Additions to property, plant and equipment	(4,619)	(9,099)	(188,823)	(202,541)
Proceeds from sale of assets	--	--	5,460	5,460
Additions to investments in unconsolidated affiliates	--	(1,910)	(36,365)	(38,275)
Cash paid for acquisitions, net of cash acquired	--	(729,000)	(435,856)	(1,164,856)
Net cash used in investing activities of continuing operations	(4,619)	(740,009)	(657,266)	(1,401,894)
Net cash provided by (used in) investing activities of discontinued operations	--	(3,523)	190,000	186,477
Net cash used in investing activities	(4,619)	(743,532)	(467,266)	(1,215,417)
Cash flows from financing activities				
Net proceeds from revolving credit facility	359,219	7,000	--	366,219
Repayments of revolving credit facility	(170,000)	(7,000)	--	(177,000)
Net proceeds from EPN Holding term credit facility	--	530,529	(393)	530,136
EPN Holding term credit facility repayments	--	(375,000)	--	(375,000)
Net proceeds from senior secured acquisition term loan	233,236	--	--	233,236
Net proceeds from senior secured term loan	156,530	--	--	156,530
Net proceeds from issuance of long-term				

debt....... 423,528 -- -- 423,528 Argo term loan
repayment.......................... -- --
(95,000) (95,000) Net proceeds from issuance of
common units......... 150,159 -- -- 150,159
Advances with
affiliates..........................
(1,038,734) 581,601 457,133 -- Contributions
from general partner................ 4,095 -- -
- 4,095 Distributions to
partners......................... (154,468) --
-- (154,468) ----------- --------- --------- ---
-------- Net cash provided by (used in)
financing activities of continuing
operations........................ (36,435)
737,130 361,740 1,062,435 Net cash used in
financing activities of discontinued
operations......................... -- (3) --
(3) ----------- --------- --------- -----------
Net cash provided by (used in) financing
activities...............................
(36,435) 737,127 361,740 1,062,432 ----------- -
-------- --------- ----------- Increase
(decrease) in cash and cash equivalents..... $
13,371 $ 15,553 $ (5,909) 23,015 ===========
========= ========= Cash and cash equivalents
Beginning of
period............................... 13,084 --
--------- End of
period.................................... $
36,099 ===========

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(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

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

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	GUARANTOR SUBSIDIARIES	CONSOLIDATED 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	--	34,455	34,778
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
Net loss on sales of assets	10,941	--	426	11,367
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				
Development expenditures for oil and natural gas properties	--	--	(2,018)	(2,018)
Additions to pipelines, platforms and facilities	(896)	--	(507,451)	(508,347)
Proceeds from sale of assets	89,162	--	19,964	109,126
Investments in unconsolidated affiliates	--	--	(1,487)	(1,487)
Cash paid for acquisitions, net of cash acquired	--	--	(28,414)	(28,414)
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 =========

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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

	ISSUER	NON-GUARANTOR SUBSIDIARIES(1)	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
Other noncash items	714	--	(727)	(13)
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				
Development expenditures for 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)
Contributions 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 =========

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(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

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

General

This footnote discusses our oil and natural gas production activities for the years 2001 and 2000. The year 2002 is not presented since these operations are not a significant part of our business as defined by SFAS No. 69, Disclosures About Oil and Gas Producing Activities, and we do not expect it to become significant in the future.

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 and 2000. Estimates of our reserves at December 31, 2001 and 2000, 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 -- 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	1,852	5,913
Production(2)	(345)	(4,172)
Proved reserves -- December 31, 2001	2,708	13,241
Proved developed reserves 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. 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	2000
	(IN THOUSANDS)	
Future cash inflows(1)	$ 80,603	$136,658
Future production costs(2)	(19,252)	(28,933)
Future development costs	(10,530)	(11,531)
Future net cash flows	50,821	96,194
Annual discount at 10% rate	(11,761)	(18,488)
Standardized measure of discounted future net cash flows	$ 39,060	$ 77,706

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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 and $13,080 for 2000. On a consolidated basis, our standardized measure of discounted future net cash flows was $43,789 for 2001 and $89,749 for 2000.

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

	PROVED DEVELOPED	PROVED UNDEVELOPED	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	2000
	(IN THOUSANDS)	
Beginning of year	$ 77,706	$ 17,829
Sales and transfers of oil and natural gas produced, net of production costs	(34,834)	(33,203)
Net changes in prices and production costs	(55,657)	119,457
Extensions, discoveries and improved recovery, less related costs	--	--
Oil and natural gas development costs incurred during the year	2,018	172
Changes in estimated future development costs	535	(511)
Revisions of previous quantity estimates	38,090	7,846
Accretion of discount	7,771	1,783
Changes in production rates, timing and other	3,431	(35,667)
End of		

year... $ 39,060 $ 77,706 ======== ========

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
	(IN THOUSANDS)	
Development costs	$2,018	$172
Capitalized interest	--	--
Total capital expenditures	$2,018	$172

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
	(IN THOUSANDS)
Oil and natural gas properties	
Proved properties	$ 54,609
Wells, equipment, and related facilities	104,766
	159,375
Less accumulated depreciation, depletion and amortization	108,307
	$ 51,068

Results of operations

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

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

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(1) These production costs include platform access fees paid to affiliated entities included in our platform 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:

	QUARTER ENDED (UNAUDITED)				
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR
	(IN THOUSANDS, EXCEPT PER UNIT DATA)				
2002					
Operating revenues	$61,544	$120,489	$122,249	$163,636	$467,918
Operating income	22,397	45,777	42,370	50,739	161,283
Income from continuing operations	14,741	28,685	23,346	25,780	92,552
Income from discontinued operations	4,385	60	456	235	5,136
Net income	19,126	28,745	23,802	26,015	97,688
Income allocation					
General Partner					
Continuing operations	$ 8,691	$ 10,799	$ 10,755	$ 11,837	$ 42,082
Discontinued operations	44	--	5	2	51
	$ 8,735	$ 10,799	$ 10,760	$ 11,839	$ 42,133
Series B preference unitholders	$ 3,552	$ 3,630	$ 3,693	$ 3,813	$ 14,688
Series C unitholders	$ --	$ --	$ --	$ 1,507	$ 1,507
Common unitholders					
Continuing operations	$ 2,498	$ 14,256	$ 8,898	$ 8,623	$ 34,275
Discontinued operations	4,341	60	451	233	5,085
	$ 6,839	$ 14,316	$ 9,349	$ 8,856	$ 39,360
Basic and diluted earnings per common unit					
Income from continuing operations	$ 0.06	$ 0.33	$ 0.20	$	

0.21 $ 0.80 Discontinued
operations.............. 0.11 -- 0.01 -
- 0.12 ------- -------- -------- ------
-- -------- $ 0.17 $ 0.33 $ 0.21 $ 0.21
$ 0.92 ======= ======== ========
======== ======== Distributions
declared per common unit.... $ 0.625 $
0.650 $ 0.650 $ 0.675 $ 2.600 =======
======== ======== ======== ========
Weighted average number of common units
outstanding.............................
39,941 42,842 44,130 44,069 42,814
======= ======== ======== ========
========

	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	22,275	69,886
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					
General Partner					
Continuing operations	$ 4,702	$ 5,902	$ 5,809	$ 8,237	$ 24,650
Discontinued operations	(7)	2	5	11	11
	$ 4,695	$ 5,904	$ 5,814	$ 8,248	$ 24,661
Series B preference unitholders	$ 4,322	$ 4,464	$ 4,538	$ 3,904	$ 17,228
Common unitholders					
Continuing operations	$ 4,692	$ 1,205	$ 1,211	$ 5,066	$ 12,174
Discontinued operations	(736)	271	474	1,077	1,086
	$ 3,956	$ 1,476	$ 1,685	$ 6,143	$ 13,260
Basic and diluted earnings per common unit					
Income from continuing operations	$ 0.14	$ 0.03	$ 0.04	$ 0.14	$ 0.35
Discontinued operations	(0.02)	0.01	0.01	0.03	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	$ 2.32
Weighted average number of common units outstanding	32,471	34,070	32,471	36,209	34,376

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 15(a)1. on page 163 present fairly, in all material respects, the financial position of El Paso Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)2 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 24, 2003

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

GENERAL

We and our general partner utilize the employees of and management services provided by El Paso Corporation and its affiliates under our general and administrative agreement. We reimburse our general partner and its affiliates for reasonable general and administrative expenses, and other reasonable expenses, incurred by them.

As a result of recent clarifications in the insider trading rules, and in particular, the promulgation of Rule 10b5-1, we have revised our insider trading policy to allow certain officers and directors to establish pre-established trading plans. Rule 10b5-1 allows certain officers and directors to establish written programs that permit an independent person who is not aware of insider information at the time of the trade to execute pre-established trades of our securities for the officer or directors according to fixed parameters. As of March 6, 2003, no officer or director has established a trading plan. However, we intend to disclose the existence of any trading plan in compliance with Rule 10b5-1 in future filings with the Securities and Exchange Commission (SEC).

GOVERNANCE MATTERS

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals, and to maintain the trust and confidence of investors, employees, suppliers, business partners and other stakeholders. The following is a brief discussion of certain existing practices and recent developments that we have undertaken to maintain strong governance principles.

Independence of Board Members. A key element for strong governance is independent members of the board of directors. Our general partner is committed to having at least a majority of its Board of Directors be comprised of independent directors. Pursuant to rules proposed by the New York Stock Exchange (NYSE), a director will be considered independent if the board determines that he or she does not have a material relationship with our general partner or us (either directly or as a partner, shareholder or officer of an organization that has a material relationship with our general partner or us). Based on the foregoing, the Board has affirmatively determined that Michael B. Bracy, H. Douglas Church and Kenneth L. Smalley are "independent" under the rules proposed by the NYSE. Thus, the Board of Directors of our general partner has a majority (60 percent) of independent directors.

Heightened Independence for Audit and Conflicts Committee Members. As required by the Sarbanes-Oxley Act of 2002, the SEC recently proposed rules that would direct national securities exchanges and associations to prohibit the listing of securities of a public company if members of its audit committee did not satisfy a heightened independence standard. In order to meet this standard, a member of an audit committee may not receive any consulting fee, advisory fee or other compensation from the public company other than fees for service as a director or committee member, and may not be considered an affiliate of the public company. Based on the foregoing criteria, the Board of Directors of our general partner has affirmatively determined that all members of the Audit and Conflicts Committee satisfy this heightened independence requirement.

Audit Committee Financial Expert. An audit committee plays an important role in promoting effective corporate governance, and it is imperative that members of an audit committee have requisite financial literacy and expertise. All members of the Audit and Conflicts Committee meet the financial literacy required by the NYSE rules. In addition, as required by the Sarbanes-Oxley Act of 2002, the SEC recently adopted rules requiring that public companies disclose whether or not its audit committee has an "audit committee financial expert" as a member. An "audit committee financial expert" is defined as a person who, based on his or her experience, satisfies all of the following attributes:

- An understanding of generally accepted accounting principles and financial statements.

- An ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves.

- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and level of complexity of issues that can reasonably be expected to be raised by El Paso Energy Partners' financial statements, or experience actively supervising one or more persons engaged in such activities.

- An understanding of internal controls and procedures for financial reporting.

- An understanding of audit committee functions.

Based on the information presented, the Board of Directors has affirmatively determined that Michael B. Bracy satisfies the definition of "audit committee financial expert."

Executive Sessions of Board. The Board of Directors of our general partner will hold regular executive sessions in which non-management board members meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, there shall be one director designated as the "Presiding Director," who shall be responsible for leading and facilitating such executive sessions. Initially, for 2003, the Presiding Director shall be the Chairman of the Audit and Conflicts Committee. Each calendar year the position of Presiding Director shall rotate among the committee chairs of the Audit and Conflicts Committee and the Governance and Compensation Committee.

Committees of Board of Directors. In response to the Sarbanes-Oxley Act of 2002 and the rules proposed by the NYSE, the Board of Directors of our general partner has made certain amendments to the charter of the Audit and Conflicts Committee. In addition, the Board has established a new Compensation and Governance Committee, the responsibilities of which are discussed below.

Governance Guidelines. Governance guidelines, together with committee charters, provide the framework for the effective governance. The Board of Directors of our general partner has adopted the El Paso Energy Partners Governance Guidelines addressing several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of committees, the conduct and frequency of board and committee meetings, management succession, director access to management and outside advisors, director compensation, director orientation and continuing education, and annual self-evaluation of the board. The Board of Directors of our general partner recognizes that effective governance is an on-going process, and thus, the Board will review the El Paso Energy Partners Governance Guidelines annually or more often as deemed necessary.

Web Access. We provide access through our website to current information relating to governance, including a copy of each Board committee charter, the Code of Business Conduct, the El Paso Energy Partners Governance Guidelines and other matters impacting our governance principles. We also provide access through our website to all filings submitted by El Paso Energy Partners with the SEC. The company's website is www.elpasopartners.com and access to this information is free of any charge to the user.

DIRECTORS AND EXECUTIVE OFFICERS OF OUR GENERAL PARTNER

The following table sets forth certain information as of March 6, 2003, regarding the executive officers and directors of our general partner. Each executive officer of our general partner serves us in the same office or offices each such officer holds with our general partner. Directors are elected annually by our general partner's sole stockholder, DeepTech International Inc., and hold office until their successors are elected and qualified. Each executive officer named in the following table has been elected to serve until his successor is duly appointed or elected or until his earlier removal or resignation from office.

On October 17, 2002, in order to move toward compliance with the New York Stock Exchange's proposed corporate governance requirements, three former directors of our general partner resigned. The resigning directors, who serve as directors and/or officers of El Paso Corporation, would not have been considered independent for purposes of the NYSE rules.

On January 28, 2003, the Board of Directors established a Governance and Compensation Committee, determined that all three independent directors (Messrs. Bracy, Church and Smalley), satisfy the independence requirements for audit committee eligibility and determined that Messr. Bracy is an audit committee financial expert as determined by the Securities and Exchange Commission rules.

There is no family relationship among any of the executive officers or directors of our general partner, and, other than described herein, no arrangement or understanding exists between any executive officer and any other person pursuant to which he was or is to be selected as an officer.

NAME	AGE	POSITION(S)
Robert G. Phillips.......	48	Director, Chairman and Chief Executive Officer
James H. Lytal...........	45	Director and President
D. Mark Leland...........	41	Senior Vice President and Chief Operating Officer
Keith B. Forman..........	44	Vice President and Chief Financial Officer
Michael B. Bracy.........	61	Director
H. Douglas Church........	65	Director
Kenneth L. Smalley.......	73	Director

Mr. Phillips has served as a Director of our general partner since August 1998. He has served as Chief Executive Officer for us and our general partner since November 1999 and as Chairman since October 2002. He served as Executive Vice President from August 1998 to October 1999. Mr. Phillips has served as President of El Paso Field Services Company since June 1997. He served as President of El Paso Energy Resources Company from December 1996 to June 1997, President of El Paso Field Services Company from April 1996 to December 1996 and Senior Vice President of El Paso from September 1995 to April 1996. For more than five years prior, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc.

Mr. Lytal has served as a Director of our general partner since August 1994 and as our President and the President of our general partner since July 1995. He served as Senior Vice President for us and our general partner from August 1994 to June 1995. Prior to joining us, Mr. Lytal served in various capacities in the oil and gas exploration and production and gas pipeline industries with United Gas Pipeline Company, Texas Oil and Gas, Inc. and American Pipeline Company.

Mr. Leland has served as Senior Vice President for us and our general partner since July 2000 and as Chief Operating Officer for us and our general partner since January 2003, and as Vice President of El Paso Field Services Company since September 1997. He served as Senior Vice President and Controller for us and our general partner from July 2000 through December 2002 and as Vice President and Controller for us and our general partner from August 1998 to July

2000. He served as Director of Business Development for El Paso Field Services Company from September 1994 to September 1997. For more than five years prior, Mr. Leland served in various capacities in the finance and accounting functions of El Paso Corporation.

Mr. Forman has served as Chief Financial Officer for us and our general partner since January 1992 and served as a Director of our general partner from July 1992 to August 1998. From 1982 to 1992, Mr. Forman served as Vice President of the Natural Gas Pipeline Group of Manufacturers Hanover Trust Company.

Mr. Bracy has served as a Director of our general partner since October 1998 and is an audit committee financial expert as determined under the Securities and Exchange Commission rules. From January 1993 to August 1997, Mr. Bracy served as a Director, Executive Vice President and Chief Financial Officer of NorAm Energy Corp. For nine years prior, Mr. Bracy served in various executive capacities with NorAm. Mr. Bracy is a member of the Board of Directors of Itron, Inc., which is not related to El Paso Energy Partners, L.P.

Mr. Church has served as a Director of our general partner since January 1999. From January 1994 to December 1998, Mr. Church served as the Senior Vice President, Transmission, Engineering and Environmental for a subsidiary of Duke Energy Corporation, Texas Eastern Transmission Company. For thirty-two years prior, Mr. Church served in various engineering and operating capacities with Texas Eastern Transmission Company, Panhandle Eastern Corporation and Transwestern Pipeline Company. Mr. Church is a past member of the Board of Directors of Southern Gas Association and is past Chairman of Boys and Girls Country of Houston, Inc., which are not related to El Paso Energy Partners, L.P.

Mr. Smalley has served as a Director of our general partner since June 2001. Mr. Smalley has been retired since February 1992. For more than five years prior to that date, Mr. Smalley was a Senior Vice President of Phillips Petroleum Company and President of Phillips 66 Natural Gas Company, a Phillips Petroleum Company subsidiary. Mr. Smalley served as a member of the Board of Directors of El Paso Corporation from 1992 to 2001.

COMPENSATION OF DIRECTORS

Non-employee directors of our general partner are entitled to receive an annual retainer fee of forty-thousand dollars, with the chairman of any board committees entitled to receive an additional fifteen thousand dollars per year. All directors of our general partner are entitled to reimbursement for their reasonable out-of-pocket expenses in connection with their travel to and from, and attendance at, meetings of the Board or Board committees thereof.

In August 1998, we adopted the 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 of the general partner 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 and such other senior officers of our general partner or its affiliates as the Chairman of the Board may designate.

In 1998, we granted 3,000 unit options to purchase an equal number of common units with an average exercise price of $26.17 per unit; in 1999, we granted 4,500 unit options to purchase an equal number of common units with an average exercise price of $21.58 per unit; in 2000, we granted 3,000 unit options to purchase an equal number of common units with an exercise price of $25.5625 per unit; in 2001, we granted 11,000 unit options to purchase an equal number of common units with an exercise price of $33.00 per unit and 4,090 restricted units; and in 2002, we granted 8,000 unit options to purchase an equal number of common units with an exercise price of $32.13 per unit and 5,429 restricted units. At March 6, 2003, 63,481 units remain unissued under the Director Plan.

AUDIT AND CONFLICTS COMMITTEE

The Audit and Conflicts Committee currently consists of Messrs. Bracy (chairman), Church and Smalley, each a non-employee director, and each of whom is "independent" (as such term is defined in the proposed amendments to the NYSE listing standards, as more fully described above). With respect to the

Audit function, the Committee advises the Board of Directors on matters regarding the system of internal controls and the annual audit by independent accountants and reviews policies and practices of our general partner and us. The Committee is responsible for the appointment, compensation, retention and oversight of any accounting firm engaged for the purpose of preparing or issuing an audit report or related work or performing other audit, review or attestation services for the Partnership and for the resolution of any potential disagreement between management and the Partnership's auditors regarding financial reporting. The Partnership's independent auditor reports directly to this Committee. With respect to the Conflicts function, the Committee, at the request of our general partner, reviews specific matters as to which our general partner believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by our general partner is fair and reasonable to us. The Committee evaluates, and where appropriate, negotiates proposed transactions, engages independent financial advisors and independent legal counsel to assist with its evaluation of the proposed transactions, and determines whether to approve and recommend the proposed transactions. The Charter of the Audit and Conflicts Committee is attached to this annual report as Exhibit 99.C.

GOVERNANCE AND COMPENSATION COMMITTEE

The Governance and Compensation Committee was formed on January 28, 2003. The Governance and Compensation currently consists of Messrs. Smalley (chairman), Bracy and Church, each a non-employee director, and each of whom is "independent" (as such term is defined in the proposed amendments to the NYSE listing standards, as more fully described above). With respect to its governance function, the Committee is responsible for developing and recommending to the Board governance principles, reviewing the qualifications of candidates for Board membership, screening possible candidates for Board membership and communicating with directors regarding Board meeting format and procedures. The Committee also has responsibility for annual performance evaluations for the Board and each committee. With respect to its compensation functions, the Committee is responsible for reviewing our executive compensation strategy to ensure that management is rewarded appropriately for its contributions to our growth and profitability and that the executive compensation strategy supports organization objectives. In consultation with the Compensation Committee of El Paso Corporation, the Committee shall review annually and approve the individual elements of total compensation for the Chief Executive Officer and other executive officers of the general partner and prepare a report on the factors and criteria on which their compensation was based. The Charter of the Compensation and Governance Committee is attached to this annual report as Exhibit 99.D.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

During 2002, only employees of El Paso Corporation and its affiliates, through our general partner, were the individuals who worked on our matters. While compensation awarded to those individuals during 2002 was handled by El Paso Corporation, the Governance and Compensation Committee is expected to handle these matters going forward. The Governance and Compensation Committee has neither interlocks nor insider participation.

COMPENSATION OF OUR GENERAL PARTNER

Our general partner receives no remuneration in connection with our management other than: (i) distributions on its general and limited partner interests in us; (ii) incentive distributions on its general partner interest, as provided in the partnership agreement, and (iii) reimbursement for all direct and indirect costs and expenses incurred, all selling, general and administrative expenses incurred, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, us, including, but not limited to the management fees paid by our general partner to a subsidiary of El Paso Corporation under its general and administrative services agreement.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Our general partner's directors, officers and beneficial owners of more than 10 percent of a registered class of our equity securities are required to file reports of ownership and reports of changes in ownership with the

SEC and the NYSE. Directors, officers and beneficial owners of more than 10 percent of our equity securities are also required to furnish us with copies of all such reports that are filed. Based on our review of copies of such forms and amendments, except as set forth below, we believe directors, executive officers and greater than 10 percent beneficial owners complied with all filing requirements during the year ended December 31, 2002. In connection with our November 2002 acquisition of the San Juan assets, El Paso Corporation and certain of its subsidiaries, including our general partner, should have filed a Form 4 reporting a change in beneficial ownership of our Series C units by December 2, 2002. The appropriate form was filed on December 9, 2002. In addition, two transactions related to our Series B Preference Units were reported late in 2002. The first transaction should have been reported on a Form 4 by September 10, 2000, and the second transaction should have been reported on a Form 4 by November 10, 2001. Both of these transactions were reported on December 9, 2002.

ITEM 11. EXECUTIVE COMPENSATION

Our executive officers and the executive officers of our general partner are compensated by El Paso Corporation and do not receive compensation from our general partner or us for their services in such capacities with the exception of awards pursuant to the Omnibus Plan discussed below. However, our general partner does make payments to a subsidiary of El Paso Corporation pursuant to its management agreement. See Item 10, Directors and Executive Officers of the Registrant -- Compensation of Directors.

OMNIBUS PLAN

In August 1998, we adopted the 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. The Omnibus Plan is administered by our general partner's Board of Directors. The Board of Directors shall interpret the Omnibus Plan, shall prescribe, amend and rescind rules relating to it, select eligible participants, make grants to participants who are not Section 16 insiders pursuant to the Securities Exchange Act, and shall take all other actions necessary for the Omnibus Plan administration, which actions shall be final and binding upon all the participants.

In August 1998, we granted 930,000 unit options to employees of our general partner to purchase an equal number of common units at $27.1875 per unit and in 2001, we granted 1,008,000 unit options to purchase an equal number of common units at $34.99 per unit pursuant to the Omnibus Plan. No grants of unit options were made in 1999, 2000 or 2002. At March 27, 2003, 1,134,500 unit options remain unissued under the Omnibus Plan.

REPORT FROM COMPENSATION COMMITTEE REGARDING EXECUTIVE COMPENSATION

Because we did not have a compensation committee or another committee performing similar functions during 2002, this report is presented by the full Board of Directors of our general partner. We have formed a Governance and Compensation Committee that will present these reports in the future. The Board of Directors of our general partner was responsible for establishing appropriate compensation goals for the knowledgeable officers and key management personnel working for us and evaluating the performance of such officers and personnel in meeting such goals.

The goals of the Board of Directors in administering compensation, including the Omnibus Plan, are as follows:

(1) To fairly compensate the knowledgeable officers and key management personnel working for us and our affiliates for their contributions to our short-term and long-term performance.

(2) To allow us to attract, motivate and retain the management personnel necessary to our success by providing an Omnibus Plan comparable to that offered by companies with which we compete for management personnel.

The elements of compensation, including of the Omnibus Plan, described above are implemented and have been periodically reviewed and adjusted by the Board of Directors. The awards made under the Omnibus Plan have been determined based on individual performance, experience and comparison with awards made by our industry peers and other companies in similar industries with comparable revenue while linking such awards to our achievement of financial goals. Going forward, the Governance and Compensation Committee, described above, will be responsible for such compensation matters.

SUMMARY COMPENSATION TABLE

The following table sets forth information concerning the annual compensation earned by our Chief Executive Officer and each of our other four most highly compensated executive officers whose annual salary and bonus during the year ended December 31, 2002, exceeded $100,000:

		ANNUAL COMPENSATION(1)			LONG-TERM COMPENSATION AWARDS	
NAME/PRINCIPAL POSITION	FISCAL YEAR	SALARY ($)	BONUS ($)	OTHER ANNUAL COMPENSATION ($)	UNIT OPTIONS (#)	ALL OTHER COMPENSATION ($)
Robert G. Phillips.............................. Chairman of the Board and Chief Executive Officer	2002	--	--	--	--	--
	2001	--	--	--	97,500	--
	2000	--	--	--	--	--
James H. Lytal.................................... President	2002	--	--	--	--	--
	2001	--	--	--	45,000	--
	2000	--	--	--	--	--
D. Mark Leland.................................... Senior Vice President and Chief Operating Officer	2002	--	--	--	--	--
	2001	--	--	--	60,000	--
	2000	--	--	--	--	--
Keith B. Forman.................................. Chief Financial Officer	2002	--	--	--	--	--
	2001	--	--	--	15,000	--
	2000	--	--	--	--	--

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(1) Other than awards made under our incentive arrangements, all other compensation was paid by El Paso Corporation or subsidiaries of El Paso Corporation.

UNIT OPTION GRANTS

No unit options were granted to the named executives during 2002.

UNIT OPTION EXERCISES AND YEAR-END VALUE TABLE

The following table sets forth information concerning unit option exercises and the fiscal year-end values of the unexercised unit options, provided on an aggregate basis, for each of the executives named in this Form 10-K.

AGGREGATED UNIT OPTION EXERCISES IN 2002 AND FISCAL YEAR-END UNIT OPTION VALUES

NAME	ACQUIRED ON EXERCISE (#)	VALUE	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS AT FISCAL YEAR-END(#)	VALUE OF UNEXERCISED IN-THE-MONEY UNITS OPTIONS AT FISCAL YEAR-END($)(1)

REALIZED($)
EXERCISABLE
UNEXERCISABLE
EXERCISABLE
UNEXERCISABLE ---
- ----------- ---
----------- -----
------ ----------
--- ----------- -

Robert G.
Phillips........
-- $-- 48,750
48,750 $ -- James
H.
Lytal...........
-- $-- 237,500
22,500 $104,813 $
-- D. Mark
Leland...........
-- $-- 30,000
30,000 $ -- $ --
Keith B.
Forman..........
-- $-- 222,500
7,500 $104,813 $
--

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(1) The figures presented in these columns have been calculated based upon the difference between $27.675, the fair market value of the common units on December 31, 2002, for each in-the-money unit option, and its exercise price. No cash is realized until the units received upon exercise of an option are sold. No stock appreciation rights were outstanding on December 31, 2002.

ITEM 12. SECURITY OWNERSHIP OF MANAGEMENT

The following table sets forth, as of March 6, 2003, the beneficial ownership of the outstanding equity securities of us, by (i) each person who is known to us to beneficially own more than 5 percent of our outstanding units, (ii) each director of our general partner and (iii) all directors and executive officers of our General Partner as a group.

TITLE OF CLASS	NAME OF BENEFICIAL OWNER	BENEFICIAL OWNERSHIP (EXCLUDING OPTIONS)(4)	UNIT OPTIONS(1)	TOTAL	PERCENT OF CLASS
Common Units	General Partner/El Paso Corporation......................	(2)	--	(2)	(2)
Common Units	Robert G. Phillips..............	10,000	48,750	58,750	*
Common Units	James H. Lytal...................	8,016(3)	237,500	245,516	*
Common Units	Keith B. Forman..................	2,000	222,500	224,500	*
Common Units	D. Mark Leland...................	4,000	30,000	34,000	*
Common Units	Michael B. Bracy.................	8,372	7,500	15,872	*
Common Units	H. Douglas Church................	4,024	6,000	10,024	*
Common Units	Kenneth L. Smalley..............	1,241	4,500	5,741	*
Common Units	Directors and executive officers as a group (7 persons)...........	37,653	556,750	594,403	1.35%

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* Less than 1 percent.

(1) The Directors and executive Officers have the right to acquire common units reflected in this column within 60 days of March 6, 2003, through the exercise of unit options.

(2) The address for our general partner and El Paso Corporation is El Paso Building, 1001 Louisiana Street, Houston, Texas 77002. All of our general partner's outstanding common stock, par value $0.10 per share, is indirectly owned by El Paso Corporation. Our general partner has no other class of capital stock outstanding. El Paso Corporation, through its subsidiaries, owned 11,674,245 common units, or 26.5 percent of our outstanding common units, 10,937,500 Series C units (each of which can be converted into one common unit after an affirmative vote of the common unitholders), 125,392 Series B preference units and our 1 percent general partner interest.

(3) The amount reflected for Mr. Lytal excludes 34 common units owned by his son, a minor.

(4) Some common units reflected in this column for certain individuals are subject to restrictions.

EQUITY COMPENSATION PLAN INFORMATION
AS OF DECEMBER 31, 2002

NUMBER OF UNITS REMAINING AVAILABLE
NUMBER OF UNITS FOR FUTURE ISSUANCE
TO BE ISSUED UPON WEIGHTED-AVERAGE
UNDER EQUITY EXERCISE OF EXERCISE
PRICE OF COMPENSATION PLANS
OUTSTANDING UNIT OUTSTANDING UNIT
(EXCLUDING UNITS OPTIONS, WARRANTS,
OPTIONS, WARRANTS REFLECTED IN PLAN
CATEGORY AND RIGHTS AND RIGHTS
COLUMN (A)) - ------------- --------
---------- ----------------- ------
------------- (A) (B) (C) Equity

compensation plans approved by common unit holders..................... -- --

Equity compensation plans not approved by common unitholders(1)...................

1,550,000 $32.17 1,175,481 ---------
------ ----------

Total.................................

1,550,000 $32.17 1,175,481 =========
====== ==========

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(1) Included in the equity compensation plans not approved by common unitholders are the El Paso Energy Partners, L.P. 1998 Omnibus Compensation Plan and 1998 Unit Option Plan for Non-Employee Directors. These plans are described in Item 8, Financial Statements and Supplementary Data, Note 8.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Historically, we have entered into transactions with El Paso Corporation and its subsidiaries to acquire or sell assets. We have instituted specific procedures for evaluating and valuing our material transactions with El Paso Corporation and its subsidiaries. Before we consider entering into a transaction with El Paso Corporation or any of its subsidiaries, we determine whether the proposed transaction (i) would comply with the requirements under our indentures and credit agreements, (ii) would comply with substantive law, and (iii) would be fair to us and our limited partners. In addition, our general partner's board of directors utilizes a Audit and Conflicts Committee comprised solely of independent directors. This committee:

- evaluates and, where appropriate, negotiates the proposed transaction;

- engages an independent financial advisor and independent legal counsel to assist with its evaluation of the proposed transaction; and

- determines whether to reject or approve and recommend the proposed transaction.

We will only consummate any proposed material acquisition or disposition with El Paso Corporation if, following our evaluation of the transaction, the Audit and Conflicts Committee approves and recommends the proposed transaction and our full Board approves the transaction.

We and El Paso Corporation and its subsidiaries share the time and effort of general partner personnel who provide services to us, including directors, officers and other personnel. These shared personnel include officers and directors who function as both our representatives and those of El Paso Corporation and its subsidiaries. Some of these shared officers and directors own and are awarded from time to time shares, or options to purchase shares, of El Paso Corporation; accordingly, their financial interests may not always be aligned completely with ours.

A discussion of certain agreements, arrangements and transactions between or among us, our general partner, El Paso Corporation and its subsidiaries and certain other related parties is summarized in Part II, Item 8, Financial Statements and Supplementary Data, Notes 2 and 9. Also see Item 10, Directors and Executive Officers of the Registrant.

ITEM 14. CONTROLS AND PROCEDURES

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls (Internal Controls) within 90 days of the filing date of this annual report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

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

Limitations on the Effectiveness of Controls. Our management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in El Paso Energy Partners' Internal Controls, or whether El Paso Energy Partners had identified any acts of fraud involving personnel who have a significant role in El Paso Energy Partners' Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Annual Report. The principal executive officer and principal financial officer note that, from the date of the controls evaluation to the date of this Annual Report, there have been no significant changes in Internal Controls or in other factors that could significantly affect Internal Controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that, subject to the limitations discussed above, the Disclosure Controls are effective to ensure that material information relating to El Paso Energy Partners and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, particularly during the period when our periodic reports are being prepared.

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

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) THE FOLLOWING DOCUMENTS ARE FILED AS PART OF THIS ANNUAL REPORT:

1. Financial Statements

Our consolidated financial statements are included in Part II, Item 8 of this report:

The following financial statements of our equity investment is included on the following pages of this report:

2. Financial statement schedules and supplementary information required to be submitted.

Schedules other than that listed above are omitted because the information is not required, is not material or is otherwise included in the consolidated financial statements or notes thereto included elsewhere in this Annual Report.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

FINANCIAL STATEMENTS
WITH REPORTS OF INDEPENDENT ACCOUNTANTS
AS OF DECEMBER 31, 2002 AND 2001 AND FOR THE THREE YEARS IN THE PERIOD ENDED
DECEMBER 31, 2002

REPORT OF INDEPENDENT ACCOUNTANTS

To the Members of Poseidon Oil Pipeline Company, L.L.C.:

In our opinion, the accompanying balance sheets and the related statements of income, members' capital, comprehensive income and changes in accumulated other comprehensive income and cash flows present fairly, in all material respects, the financial position of Poseidon Oil Pipeline Company, L.L.C. (the "Company") at December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company'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. The financial statements of the Company as of December 31, 2000 and for the year then ended were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on those financial statements in their report dated March 16, 2001.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 24, 2003

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Members of
Poseidon Oil Pipeline Company, L.L.C.:

We have audited the accompanying balance sheet of Poseidon Oil Pipeline Company, L.L.C. (a Delaware limited liability company), as of December 31, 2000, and the related statements of income, members' equity and cash flows for the years ended December 31, 2000 and 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Poseidon Oil Pipeline Company, L.L.C., as of December 31, 2000, and the results of its operations and its cash flows for the years ended December 31, 2000 and 1999, in conformity with accounting principles generally accepted in the United States.

/s/ ARTHUR ANDERSEN LLP

Houston, Texas
March 16, 2001

THIS REPORT IS A COPY OF A PREVIOUSLY ISSUED REPORT AND THIS REPORT HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP. THE REFERENCED 1999 FINANCIAL STATEMENTS ARE NOT INCLUDED IN THE FINANCIAL STATEMENTS AS OF AND FOR THE YEAR ENDED DECEMBER 31, 2002.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF INCOME
(IN THOUSANDS)

FOR THE YEARS ENDED DECEMBER 31,	2002	2001	2000
Operating revenues			
Transportation revenues and crude oil sales............	$1,086,757	$1,196,840	$1,466,086
Operating expenses			
Transportation costs and crude oil purchases...........	1,032,496	1,126,439	1,402,721
Operation and maintenance.............................	4,691	1,586	4,487
Repair expenses.......................................	--	--	18,118
Depreciation and amortization.........................	8,356	10,552	10,754
	1,045,543	1,138,577	1,436,080
Operating income......................................	41,214	58,263	30,006
Other income (expense)			
Interest income.......................................	95	394	639
Interest and debt expense.............................	(6,923)	(7,668)	(11,683)
Other income..	26,600	--	--
Net income..	$ 60,986	$ 50,989	$ 18,962

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

BALANCE SHEETS
AS OF DECEMBER 31, 2002 AND 2001
(IN THOUSANDS)

	2002	2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 27,606	$ 1,095
Accounts receivable, trade	92,646	53,394
Accounts receivable, affiliate	30,142	39,253
Other current assets	2,390	2,486
Total current assets	152,784	96,228
Property, plant and equipment, net	214,497	222,363
Debt reserve fund	3,551	3,499
Other noncurrent assets	415	708
Total assets	$371,247	$322,798
LIABILITIES AND MEMBERS' CAPITAL		
Current liabilities		
Accounts payable, trade	$ 84,191	$ 45,439
Accounts payable, affiliate	34,398	39,787
Interest rate hedge liabilities	1,385	--
Total current liabilities	119,974	85,226
Revolving credit facility	148,000	150,000
Commitments and contingencies		
Members' capital		
Members' capital before accumulated other comprehensive income	104,658	87,572
Accumulated other comprehensive income	(1,385)	--
Total members' capital	103,273	87,572
Total liabilities and members' capital	$371,247	$322,798

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	FOR THE YEARS ENDED DECEMBER 31,		
	2002	2001	2000
Cash flows from operating activities			
Net income	$ 60,986	$ 50,989	$ 18,962
Adjustments to reconcile net income to cash provided by operating activities			
Depreciation and amortization	8,356	10,552	10,754
Amortization of debt issue costs	293	186	--
Changes in operating assets and liabilities			
(Increase) decrease in accounts receivable	(30,141)	27,561	48,828
Decrease (increase) in other current assets	96	99	(2,993)
Increase (decrease) in accounts payable	33,363	(29,550)	(44,491)
(Decrease) increase in reserve for revenue refund	--	(1,297)	975
Decrease in other current liabilities	--	--	(93)
Net cash provided by operating activities	72,953	58,540	31,942
Cash flows from investing activities			
Capital expenditures	(3,890)	(124)	(3,323)
Construction advances to operator	--	--	4
Proceeds from sale of assets	3,400	--	--
Net cash used in investing activities	(490)	(124)	(3,319)
Cash flows from financing activities			
Repayments of long-term debt	(2,000)	--	--
Debt issue costs	--	(894)	--
Contributions from partners	--	--	10,900
Distributions to partners	(43,900)	(61,699)	(37,588)
(Increase) decrease in debt reserve fund	(52)	2,740	(1,456)
Net cash used in financing activities	(45,952)	(59,853)	(28,144)
Increase (decrease) in cash and cash equivalents	26,511	(1,437)	479
Cash and cash equivalents:			
Beginning of period	1,095	2,532	2,053
End of period	$ 27,606	$ 1,095	$ 2,532
Supplemental disclosure of cash flow information			
Cash paid for interest, net of amounts capitalized	$ 5,959	$ 6,423	$ 11,683

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF MEMBERS' CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000
(IN THOUSANDS)

	POSEIDON PIPELINE COMPANY, L.L.C. (36%)	SHELL OIL PRODUCTS U.S. (36%)	MARATHON OIL COMPANY (28%)	TOTAL
Balance at January 1, 2000	$ 38,163	$ 38,163	$ 29,682	$106,008
Cash contributions	3,924	3,924	3,052	10,900
Cash distributions	(13,532)	(13,532)	(10,524)	(37,588)
Net income	6,826	6,826	5,310	18,962
Balance at December 31, 2000	35,381	35,381	27,520	98,282
Cash distributions	(22,212)	(22,212)	(17,275)	(61,699)
Net income	18,356	18,356	14,277	50,989
Balance at December 31, 2001	31,525	31,525	24,522	87,572
Cash distributions	(15,804)	(15,804)	(12,292)	(43,900)
Net income	21,955	21,955	17,076	60,986
Other comprehensive loss	(498)	(498)	(389)	(1,385)
Balance at December 31, 2002	$ 37,178	$ 37,178	$ 28,917	$103,273

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

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

	FOR THE YEARS ENDED DECEMBER 31,		
	2002	2001	2000
COMPREHENSIVE INCOME			
Net income	$60,986	$50,989	$18,962
Other comprehensive loss	(1,385)	--	--
Total comprehensive income	$59,601	$50,989	$18,962
ACCUMULATED OTHER COMPREHENSIVE INCOME			
Beginning balance	$ --	$ --	$ --
Unrealized net loss from interest rate swap	(1,385)	--	--
Ending balance	$(1,385)	$ --	$ --

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

NOTES TO FINANCIAL STATEMENTS

NOTE 1 -- ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Poseidon Oil Pipeline Company, L.L.C. is a Delaware limited liability company, formed in February 1996, to design, construct, own and operate the unregulated Poseidon Pipeline extending from the Gulf of Mexico to onshore Louisiana.

Our members are Shell Oil Products U.S. (Shell) (formerly Equilon Enterprises, L.L.C.), Poseidon Pipeline Company, L.L.C. (Poseidon), a subsidiary of El Paso Energy Partners, L.P., and Marathon Pipeline Company (Marathon), which own 36 percent, 36 percent, and 28 percent in us.

Shell was our operator from January 1, 1998 to December 31, 2000. Effective January 1, 2001, Manta Ray Gathering Company, L.L.C., a subsidiary of El Paso Energy Partners and an affiliate of ours became our operator.

We are in the business of transporting crude oil in the Gulf of Mexico in accordance with various purchase and sale contracts with producers served by our pipeline. We buy crude oil at various points along the pipeline and resell the crude oil at a destination point in accordance with each individual contract. Our margin is earned based upon the differential between the sales price and the purchase price and represents our earnings from providing transportation services. Differences between measured purchased and sold volumes in any period are recorded as changes in exchange imbalances with producers. In addition, we transport crude oil for a fee.

Basis of Presentation

Our financial statements are prepared on the accrual basis of accounting in conformity with accounting principles generally accepted in the United States. Our financial statements for previous periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or members' capital.

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 considered cash equivalents.

Debt Reserve Fund

In connection with our revolving credit facility, we are required to maintain a debt reserve account as collateral on the outstanding balances. At December 31, 2002 and 2001, the balance in the account was approximately $3.6 million and $3.5 million, and consisted of funds earning interest at 1.5% and 1.7%.

Allowance for Doubtful Accounts

Collectibility of accounts receivable is reviewed regularly and an allowance is recorded as necessary, primarily under the specific identification method. At December 31, 2002 and 2001, no allowance for doubtful accounts was recorded.

Property, Plant and Equipment

Contributed property, plant and equipment is recorded at fair value as agreed to by the members at the date of contribution. Acquired property, plant and equipment is recorded at cost. Pipeline equipment is depreciated using a composite, straight-line method over the estimated useful lives of 3 to 30 years. Line-fill is not depreciated, as our management believes the cost of all barrels is fully recoverable. Repair and maintenance costs are expensed as incurred, while additions, improvements and replacements are capitalized. No gain or loss is recognized on normal asset retirements under the composite method.

Impairment and Disposal of Long-Lived Assets

We adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets on January 1, 2002. Accordingly, we evaluate the recoverability of selected long-lived assets when adverse events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. We determine the recoverability of an asset or group of assets by estimating the undiscounted cash flows expected to result from the use and eventual disposition of the asset or group of assets at the lowest level for which separate cash flows can be measured. If the total of the undiscounted cash flows is less that the carrying amount for the assets, we estimate the fair value of the asset or group of assets and recognize the amount by which the carrying value exceeds the fair value as an impairment loss in income from operations in the period the impairment is determined. Our adoption of SFAS No. 144 did not have a material impact on our financial position or result of operations.

Additionally, as required by SFAS No. 144, we classify long-lived assets to be disposed of other than by sale (e.g., abandonment, exchange or distribution) as held and used until the item is abandoned, exchanged or distributed. We evaluate assets to be disposed of other than by sale for impairment and recognize a loss for the excess of the carrying value over the fair value. Long-lived assets to be disposed of through sale recognition meeting specific criteria are classified as "Held for Sale" and measured at the lower of their cost or fair value less cost to sell. We report the results of operations of a component classified as held for sale, including any gain or loss recognized in discontinued operations in the period(s) in which they occur and all prior periods presented.

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated. As of December 31, 2002 and 2001, debt issue costs of $415 thousand and $708 thousand are classified as an other noncurrent asset on our balance sheet.

Fair Value of Financial Instruments

The estimated fair values of our cash and cash equivalents, accounts receivable and accounts payable approximate their carrying amounts in the accompanying balance sheet due to the short-term maturity of these instruments. The fair value of our long-term debt with variable interest rates approximates its carrying value because of the market-based nature of the debt's interest rates.

Revenue Recognition

Revenue from crude oil sales is recognized upon delivery. Revenue from pipeline transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline system.

Comprehensive Income

Our comprehensive income is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income (loss) from our cash flow hedging activities associated with our interest rate hedge for our revolving credit facility.

Crude Oil Imbalances

In the course of providing transportation services for customers, we may receive different quantities of crude oil than the quantities delivered. These transactions result in imbalances that are settled in kind the following month. We value our imbalances based on the weighted average acquisition price of produced barrels for the current month. Our imbalance receivables and imbalance payables were classified on our balance sheet as follows on December 31 (in thousands):

	2002	2001
Imbalance Receivables		
Trade	$2,123	$1,897
Affiliates	$ 564	$2,690
Imbalance Payables		
Trade	$3,841	$1,865
Affiliates	$3,927	$2,996

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 Hedging Activities

We apply the provisions issued in SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities to account for price risk management activities. This statement requires us to measure all derivative instruments at their fair value, and classify them as either assets or liabilities on our balance sheet, with the corresponding offset to income or other comprehensive income depending on their designation, their intended use, or their ability to qualify as hedges under the standard. As of December 31, 2002, the fair value of our interest rate swap was a liability of $1.4 million resulting in accumulated other comprehensive loss of $1.4 million.

In January 2002, we entered into a two-year interest rate swap agreement with Credit Lyonnais to fix the variable LIBOR based interest rate on $75 million of our variable rate revolving credit facility at 3.49% through January 2004. Under our credit facility, we currently pay an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Collateral was not required and we do not anticipate non-performance by the counter party.

Income Taxes

We are organized as a Delaware limited liability company and treated as a partnership for income tax purposes, and as a result, the income or loss resulting from our operations for income tax purposes is included in the federal and state tax returns of our members. Accordingly, no provision for income taxes has been recorded in the accompanying financial statements.

Management's 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 effect 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.

Income Allocation and Cash Distributions

Our income is allocated to our members based on their ownership percentages. At times, we may make cash distributions to our members in amounts determined by our Management Committee, which is responsible for conducting our affairs in accordance with our limited liability agreement.

Limitations of Member's Liability

As a limited liability company, our members or their affiliates are not personally liable for any of our debts, obligations or liabilities simply because they are our members.

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 combinations we undertake in the future will be impacted by this standard. Our adoption of SFAS No. 141 did not have a material effect on our financial position or results of operations.

Accounting for Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement requires companies to record a liability for the estimated 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. Capitalized retirement and removal costs will be depreciated over the useful life of the related asset. The provisions of this statement are effective for fiscal years beginning after June 15, 2002. We are required to adopt the provisions of SFAS No. 143 as of January 1, 2003 and will record an adjustment for the cumulative effect of initially adopting this statement in our statement of income. Our adoption of this statement will not have a material effect on our financial position or results of operations.

Reporting Gains and Losses from the Early Extinguishment of Debt

In April 2002, the FASB issued SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64. Amendment of FASB Statement No. 13, and Technical Corrections. This statement addresses how to report gains or losses resulting from the early extinguishment of debt. Previously, any gains or losses were reported as an extraordinary item. Upon adoption of SFAS No. 145, an entity will be required to evaluate whether the debt extinguishment is truly extraordinary in nature, in accordance with Accounting Principles Board Opinion No. 30. If the entity routinely extinguishes debt early, the gain or loss should be included in income from continuing operations. This statement is effective for our 2003 year-end reporting.

Accounting for Costs Associated with Exit or Disposal Activities

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. This statement requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activity. The provisions of this statement are effective for fiscal years beginning after December 31, 2002. The provisions of this statement will impact any exit or disposal activities that we initiate after January 1, 2003.

Accounting for Guarantees

In November 2002, the FASB issued FASB Interpretation (FIN) No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. This interpretation requires that companies record a liability for all guarantees issued or modified after December 31, 2002, including financial, performance, and fair value guarantees. This liability is recorded at its fair value upon issuance, and does not affect any existing guarantees issued before January 31, 2003. This standard also requires expanded disclosures on all existing guarantees at December 31, 2002. We do not currently guarantee the indebtedness of others; however the recognition, measurement and disclosure provisions of this interpretation will apply to any guarantees we may make in the future.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities. This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003 for all variable interest entities created before January 31, 2003. Our adoption of this statement will not have a material effect on our financial position or results of operations.

NOTE 2 -- PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	DECEMBER 31, 2002	DECEMBER 31, 2001
	(IN THOUSANDS)	
Pipeline and equipment, at cost	$264,903	$266,614
Construction work in progress	942	706
	265,845	267,320
Less accumulated depreciation	(51,348)	(44,957)
Total property, plant and equipment, net	$214,497	$222,363

During 2002 and 2001, we did not capitalize interest costs into property, plant and equipment.

NOTE 3 -- LONG-TERM DEBT

In April 2001, we amended and restated our revolving credit facility to provide up to $185 million for construction and expansion of our system and for other working capital changes. Our ability to borrow money under this facility is subject to certain customary terms and conditions, including borrowing base limitations, and we are required to maintain a debt service reserve equal to two quarters' interest. This facility is collateralized by a substantial portion of our assets and matures in April 2004. As of December 31, 2002, and 2001, we had $148 million and $150 million outstanding under this facility with the full unused amount available. The average variable floating interest rate was 3.4% and 3.9% at December 31, 2002 and 2001. We pay a variable commitment fee on the unused portion of the credit facility. The fair value of our revolving credit facility with variable interest rates approximates its carrying value because of the market based nature of our debt's interest rates. During the first quarter of 2003, we reduced the outstanding balance of our revolving credit facility by $21 million.

Our revolving credit facility contains covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets and dividend restrictions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations.

Under our revolving credit facility, the financial debt covenants are:

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

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

(c) the ratio of our total indebtedness to EBITDA, as defined in our credit facility, for the four quarters ending on the last day of the current quarter shall not exceed 3.00 to 1.00.

We are in compliance with the above covenants as of the date of this filing.

In January 2002, we entered into a two-year interest rate swap to fix the variable LIBOR based interest rate on $75 million of our revolving facility at 3.49 percent through January 2004. Under our credit facility, we currently pay an additional 1.50% over the LIBOR rate resulting in an effective rate of 4.99% on the hedged notional amount.

We use interest rate swaps to limit our exposure to fluctuations in interest rates. These interest rate swaps are accounted for in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. As of December 31, 2002, the fair value of our interest rate swap was a liability of $1.4 million resulting in accumulated other comprehensive loss of $1.4 million. The entire amount will be reclassified from accumulated other comprehensive income to earnings proportionately over the next twelve months. Additionally, we have recognized in income a realized loss of $1.2 million for the twelve months ended December 31, 2002, as interest expense.

NOTE 4 -- MAJOR CUSTOMERS

The percentage of our transportation services and crude oil sales revenues from major customers were as follows:

	FOR THE YEAR ENDED DECEMBER 31,	
	2002	2001
	% OF TOTAL REVENUES	% OF TOTAL REVENUES
Marathon Oil Company(1)	15%	20%
British-Borneo USA, Inc.	14%	--
Chevron Texaco Corporation	11%	1%
El Paso Production(1)	10%	1%
Equiva Trading Company(1)	9%	15%
Amerada Hess Company	8%	16%
Texon L.P.	6%	10%
Anadarko	3%	10%

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(1) Represents affiliated companies.

NOTE 5 -- RELATED PARTY TRANSACTIONS

We derive a portion of our gross sales and gross purchases from our members and their affiliated companies. We generated approximately $449 million and $489 million in gross affiliated sales and approximately $434 million and $489 in gross affiliated purchases for 2002 and 2001.

We paid Manta Ray Gathering Company, L.L.C., a subsidiary of El Paso Energy Partners, approximately $2.1 million for management, administrative and general overhead in 2002 and in 2001. Prior to Manta Ray Gathering Company, L.L.C., taking over as operator, Shell received approximately $1.1 million in 2000 for management, administrative and general overhead. During 2000, we were charged and paid Shell an additional management fee of approximately $1.7 million associated with the repair of our ruptured pipeline. Our other members disputed this additional charge and we were subsequently reimbursed $1.6 million in 2001.

NOTE 6 -- COMMITMENTS AND CONTINGENCIES

Legal

In the normal course of business, we are involved in various legal actions arising from our operations. In the opinion of management, the outcome of these legal actions will not have a significant adverse effect on our financial position or results of operations.

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 have no reserves for environmental matters, and during the next five years, we do not expect to make any significant capital expenditures relating to 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.

Other

We are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico and regulation under the Hazardous Liquid Pipeline Safety Act. Operations in offshore federal waters are regulated by the United States Department of the Interior.

In February 1998, we entered into an oil purchase and sale agreement with Pennzoil Exploration and Production (Pennzoil). The agreement provides that if Pennzoil delivers at least 7.5 million barrels by September 2003, we will refund $0.51 per barrel for all barrels delivered plus interest at 8 percent. At December 31, 2002, we believe that we have no obligation under this agreement. Also, in December 2001, based on barrels delivered through December 31, 2001 and our estimates through September 2003, we believed Pennzoil would not meet its minimum delivery requirement. Accordingly, we reversed our accrual for revenue refund of $1.7 million at December 31, 2001 and recorded it as a component of operating revenue in 2001.

In January 2000, an anchor from a submersible drilling unit of Transocean 96 (Transocean) in tow ruptured our 24-inch crude oil pipeline north of the Ship Shoal 332 platform. The accident resulted in the release of approximately 2,200 barrels of crude oil in the waters surrounding our system, caused damage to the Ship Shoal 332 platform, and resulted in the shutdown of our system. Our cost to repair the damaged pipeline and clean up the crude oil released into the Gulf of Mexico was approximately $18 million and was charged to repair expenses in the year ended December 31, 2000. By the end of the first quarter 2000, our pipeline was repaired and placed back into service. In November 2002, we reached a settlement with multiple parties relating to this rupture and have recorded the proceeds of $26.6 million as other income in our 2002 statement of income.

SCHEDULE II

EL PASO ENERGY PARTNERS, L.P.

VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000
(IN THOUSANDS)

DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	CHARGED TO COSTS AND EXPENSES	CHARGED TO OTHER ACCOUNTS	DEDUCTIONS	BALANCE AT END OF PERIOD
2002					
Allowance for doubtful accounts.......	$1,819	$ 700	$ --	$ --	$ 2,519
Environmental reserve.................	--	--	21,136(1)	--	21,136
Regulatory reserve....................	--	370	--	--	370
2001					
Allowance for doubtful accounts.......	$ 380	$1,439	$ --	$ --	$ 1,819
2000					
Allowance for doubtful accounts.......	$ --	$ --	$ 380	$ --	$ 380

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(1) Our environmental reserve is for environmental liabilities assumed in our EPN Holding asset acquisition during 2002. This reserve was included in our allocation of the purchase price for the acquisition.

EL PASO ENERGY PARTNERS, L.P.

EXHIBIT LIST
DECEMBER 31, 2002

Each exhibit identified below is filed as a part of this Annual Report. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(c) of Form 10-K.

EXHIBIT NUMBER DESCRIPTION
-------------- -----------
3.A -- Amended and Restated Certificate of Limited Partnership dated February 14, 2002 (Exhibit 3.A of our 2001 Form 10-K). 3.B -- Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Report on Form 8-K dated March 6, 2001); First Amendment dated November 27, 2002, to the Second Amended and Restated Agreement of Limited Partnership (Exhibit 3.B.1 to our Current Report on Form 8-K dated December 11, 2002). 4.C -- Registration Rights Agreement dated as of August 28, 2000 by and between Crystal Gas Storage, Inc. and El Paso Energy

Partners, L.P. (Exhibit 4.3 to our 2000 Form 10-K). 4.D -- Indenture dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4, filed on June 24, 1999, File Nos. 333-81143 through 333-81143-17); First Supplemental Indenture dated as of June 30, 1999 (Exhibit 4.2 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999 File Nos. 333-81143 through 333-81143-17); Second Supplemental Indenture dated as of July 27, 1999 (Exhibit 4.3 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999, File Nos. 333-81143 through 333-81143-17); Third Supplemental Indenture dated as of March 21, 2000, to the Indenture dated as of May 27, 1999, (Exhibit 4.7.1 to our 2000 Second Quarter Form 10-Q); Fourth Supplemental Indenture dated as of July 11, 2000. (Exhibit 4.2.1 to our 2001 Third Quarter Form 10-Q); Fifth Supplemental Indenture dated as of August 30, 2000 (Exhibit 4.2.2 to our 2001 Third Quarter Form 10-Q); Sixth Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.1 to our 2002 First Quarter Form 10-Q); Seventh Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.2 to our 2002 First Quarter Form 10-Q); Eighth Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.D.3 to our 2002 Third Quarter Form 10-Q); Ninth Supplemental Indenture dated as of November 27, 2002 to the

Indenture dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors and JPMorgan Chase Bank, as Trustee (Exhibit 4.D.1 to our Current Report on Form 8-K dated March 19, 2003); Tenth Supplemental Indenture dated as of January 1, 2002 to the Indenture dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors and JPMorgan Chase Bank, as Trustee (Exhibit 4.D.2 to our Current Report on Form 8-K dated March 19, 2003).

EXHIBIT NUMBER DESCRIPTION
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4.E -- Indenture dated as of May 11, 2000 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, The Subsidiary Guarantors named therein and The Chase Manhattan Bank, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.1 to our 2002 First Quarter Form 10-Q); Second Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.2 to our 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.E.3 to our 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 to the Indenture dated as of May 17, 2001 among El Paso Energy Partners, L.P., El Paso Energy Partners

Finance Corporation, The Subsidiary Guarantors and JPMorgan Chase Bank, as Trustee (Exhibit 4.E.1 to our Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 to the Indenture dated as of May 17, 2001 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, The Subsidiary Guarantors and JPMorgan Chase Bank, as Trustee (Exhibit 4.E.2 to our Current Report on Form 8-K dated March 19, 2003).

4.F -- Letter agreement dated March 5, 2002, between Crystal Gas Storage, Inc. and El Paso Energy Partners, LP (Exhibit 4.F of our 2001 Form 10-K).

4.F -- A/B Exchange Registration Rights Agreement dated as of May 17, 2002, by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the subsidiary guarantors party thereto, Credit Suisse First Boston

Corporation, Goldman, Sachs & Co., J.P. Morgan Securities Inc., Banc One Capital Markets, Inc., Fleet Securities, Inc., Fortis Investment Services L.L.C., The Royal Bank of Scotland plc, BNP Securities Corp. and First Union Securities, Inc. (Exhibit 4.3 to our Registration Statement on Form S-4 filed August 12, 2002). 4.G -- Registration Rights Agreement by and between El Paso Corporation and El Paso Energy Partners, L.P. dated as of November 27, 2002 (Exhibit 4.G to our Current Report on Form 8-K dated December 11, 2002). 4.H -- A/B Exchange Registration Rights Agreement by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors party thereto, J.P. Morgan Securities Inc., Goldman, Sachs & Co., UBS Warburg LLC and Wachovia Securities, Inc. dated as of November 27, 2002 (Exhibit 4.H to our Current

Report on Form 8-K dated December 11, 2002). 4.I -- Indenture dated as of November 27, 2002 by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (Exhibit 4.I to our Current Report on Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 to the Indenture dated as of November 27, 2002 by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (Exhibit 4.I.1 to our Current Report on Form 8-K dated March 19, 2003). 10.A -- Amended and Restated General and Administrative Services Agreement by and between DeepTech International Inc., El Paso Energy Partners Company and El Paso Field Services, L.P. dated November 27,

2002 (Exhibit
10.A to our
2002 Third
Quarter Form
10-Q).

EXHIBIT NUMBER DESCRIPTION - ------------------------

10.B -- Sixth Amended and Restated Credit Agreement dated as of March 23, 1995, as amended and restated through October 10, 2002 by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, Credit Lyonnais New York Branch and First Union National Bank, as Co-Syndication Agents, Fleet National Bank and Fortis Capital Corp., as Co-Documentation Agents, The Chase Manhattan Bank, as Administrative Agent, and the several banks and other financial institutions signatories thereto (Exhibit 10.B to our 2002 Third Quarter Form 10-Q); First Amendment dated as of November 21, 2002 (filed as Exhibit 10.B.1 to our Current Report on Form 8-K dated March 19, 2003).

10.G -- Limited Liability Company Agreement for Poseidon Oil Pipeline Company, L.L.C. dated

February 14, 1996; First Amendment to the Limited Liability Company Agreement for Poseidon Oil Pipeline Company, L.L.C. dated February 14, 1996. (collectively attached as Exhibit 10.14 to our 2000 First Quarter Form 10-Q). 10.I -- Purchase and Sale Agreement dated as of September 27, 2001 by and between American Natural Offshore Company, Texas Offshore Pipeline System, Inc., Unitex Offshore Transmission Company and ANR Western Gulf Holdings, L.L.C. as Sellers and El Paso Energy Partners Deepwater, L.L.C., as Buyer (Exhibit 2.1 to our Report on Form 8-K dated October 25, 2001). 10.L+ -- 1998 Unit Option Plan for Non-Employee Directors Amended and Restated effective as of April 18, 2001. (Exhibit 10.1 to our 2001 Second quarter Form 10-Q). 10.M+ -- 1998 Omnibus Compensation Plan, Amended and Restated, effective as of January 1, 1999 (Exhibit 10.9 to our 1998 Form 10-K); Amendment

No. 1 dated as of December 1, 1999. (Exhibit 10.8.1 to our 2000 Second Quarter Form 10-Q). 10.N -- Purchase, Sale and Merger Agreement by and between El Paso Tennessee Pipeline Co. and El Paso Energy Partners, L.P., dated as of April 1, 2002 (Exhibit 10.N to our 2002 First Quarter Form 10-Q). 10.O -- Contribution Agreement by and between El Paso Field Services Holding Company and El Paso Energy Partners, L.P. dated as of April 1, 2002 (Exhibit 10.O to our 2002 First Quarter Form 10-Q). 10.P -- Purchase and Sale Agreement by and between El Paso Energy Partners, L.P. and El Paso Production GOM Inc. dated as of April 1, 2002 (Exhibit 10.P to our 2002 First Quarter Form 10-Q). 10.Q -- Amended and Restated Credit Agreement among EPN Holding Company, L.P., the Lenders party thereto, Banc One Capital Markets, Inc. and Wachovia Bank, N.A., as Co-Syndication Agents, Fleet National Bank and Fortis Capital Corp., as Co-Documentation Agents, and JPMorgan Chase Bank, as Administrative Agent, dated as of April 8, 2002 (Exhibit 10.Q to our 2002 Third Quarter Form 10-Q); First Amendment dated as of November 21, 2002 (filed as Exhibit 10.Q.1 to our Current Report on Form 8-K dated March 19, 2003).

10.R -- Letter Agreement by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors party thereto, JPMorgan Chase Bank, Goldman Sachs Credit Partners L.P., UBS AG, Stamford Branch and Wachovia Bank, National Association dated November 27, 2002 (Exhibit 10.R to our Current Report on Form 8-K dated March 19, 2003).

10.S -- Senior Secured Acquisition Term Loan Credit Agreement dated as of November 27, 2002 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance

Corporation, the Lenders party thereto, Goldman Sachs Credit Partners L.P., as Documentation Agent, UBS Warburg LLC and Wachovia Bank, National Association, as Co-Syndication Agents and JPMorgan Chase Bank, as Administrative Agent (Exhibit 10.S to our Current Report on Form 8-K dated March 19, 2003).

EXHIBIT NUMBER DESCRIPTION -------------- --------- -- 10.T -- Contribution, Purchase and Sale Agreement by and between El Paso Corporation and El Paso Energy Partners, L.P. dated November 21, 2002 (Exhibit 2.A to our Current Report on Form 8-K dated December 11, 2002). *21. -- Subsidiaries of El Paso Energy Partners, L.P. *23.A -- Consent of Independent Accountants. *23.B -- Consent of Independent Petroleum Engineers. *99.A -- Certification of Robert G. Phillips, Chief Executive Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. A signed original of this written statement required by Section 906 has been provided to El Paso Energy Partners, L.P. and will be retained by El Paso Energy Partners, L.P. and furnished to the

Securities and Exchange Commission or its staff upon request. *99.B -- Certification of Keith B. Forman, Chief Financial Officer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. A signed original of this written statement required by Section 906 has been provided to El Paso Energy Partners, L.P. and will be retained by El Paso Energy Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request. *99.C -- El Paso Energy Partners Company Audit and Conflicts Committee Charter effective January 21, 2003. *99.D -- El Paso Energy Partners Company Governance and Compensation Committee Charter effective January 21, 2003.

(b) REPORTS ON FORM 8-K

- We filed a current report on Form 8-K dated November 15, 2002 to update the financial statements and pro forma financial information filed in connection with the proposed San Juan assets acquisition from El Paso Corporation, as well as the proposed financing plan.

- We filed a current report on Form 8-K dated December 2, 2002 to announce the completion of the acquisition of the San Juan assets from El Paso Corporation on November 27, 2002.

- We filed a current report on Form 8-K dated December 11, 2002 disclosing our acquisition of the San Juan assets from El Paso Corporation on November 27, 2002.

- We filed a current report on Form 8-K dated December 26, 2002 to amend the Form 8-K dated December 11, 2002, and to update the pro forma financial information previously filed in our Current Reports on Form 8-K.

- We filed a current report on Form 8-K dated January 2, 2003 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 into the Form 8-K/A filed July 19, 2002, which was filed to conform our historical financial presentation and the changes in our segment presentation in our Form 10-Q for the quarterly period ended March 31, 2002.

- We filed a current report on Form 8-K dated March 19, 2003 to update our current risk factors discussion and to provide additional information relating to us, our operations and our relationship with El Paso Corporation.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso Energy Partners, L.P. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the twenty-seventh day of March 2003.

EL PASO ENERGY PARTNERS, L.P.
(Registrant)

By: EL PASO ENERGY PARTNERS COMPANY,
its General Partner

By: /s/ ROBERT G. PHILLIPS

Robert G. Phillips
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of El Paso Energy Partners, L.P. and in the capacities and on the dates indicated:

NAME TITLE
DATE ----
----- ----
/s/ ROBERT
G.
PHILLIPS
Chief
Executive
Officer
and March
27, 2003 -

Chairman
of the
Board and
Robert G.
Phillips
Director
/s/ JAMES
H. LYTAL
President
and
Director
March 27,
2003 - ---

James H.
Lytal /s/
D. MARK
LELAND
Senior
Vice
President
and Chief
March 27,
2003 - ---

Operating
Officer D.
Mark
Leland /s/
KEITH B.
FORMAN

Chief Financial Officer and March 27, 2003 - -- --- Vice President Keith B. Forman /s/ KATHY A. WELCH Vice President and Controller March 27, 2003 - --- -- (Principal Accounting Kathy A. Welch Officer) /s/ MICHAEL B. BRACY Director March 27, 2003 - --- -- Michael B. Bracy /s/ H. DOUGLAS CHURCH Director March 27, 2003 - --- -- H. Douglas Church /s/ KENNETH L. SMALLEY Director March 27, 2003 - --- -- Kenneth L. Smalley

CERTIFICATION

I, Robert G. Phillips, certify that:

1. I have reviewed this annual report on Form 10-K of El Paso Energy Partners, L.P.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

(c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

/s/ ROBERT G. PHILLIPS

Robert G. Phillips
Chief Executive Officer
El Paso Energy Partners Company,
general partner of El Paso Energy
Partners, L.P.

CERTIFICATION

I, Keith B. Forman, certify that:

1. I have reviewed this annual report on Form 10-K of El Paso Energy Partners, L.P.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

(c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

/s/ KEITH B. FORMAN

Keith B. Forman
Chief Financial Officer
El Paso Energy Partners Company,
general partner of El Paso Energy
Partners, L.P.

EL PASO ENERGY PARTNERS, L.P.

INDEX TO EXHIBITS
DECEMBER 31, 2002

Each exhibit identified below is filed as a part of this Annual Report. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(c) of Form 10-K.

EXHIBIT NUMBER DESCRIPTION
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3.A -- Amended and Restated Certificate of Limited Partnership dated February 14, 2002 (Exhibit 3.A of our 2001 Form 10-K). 3.B -- Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Report on Form 8-K dated March 6, 2001); First Amendment dated November 27, 2002, to the Second Amended and Restated Agreement of Limited Partnership (Exhibit 3.B.1 to our Current Report on Form 8-K dated December 11, 2002). 4.C -- Registration Rights Agreement dated as of August 28, 2000 by and between Crystal Gas Storage, Inc. and El Paso Energy

Partners, L.P. (Exhibit 4.3 to our 2000 Form 10-K). 4.D -- Indenture dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4, filed on June 24, 1999, File Nos. 333-81143 through 333-81143-17); First Supplemental Indenture dated as of June 30, 1999 (Exhibit 4.2 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999 File Nos. 333-81143 through 333-81143-17); Second Supplemental Indenture dated as of July 27, 1999 (Exhibit 4.3 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999, File Nos. 333-81143 through 333-81143-17); Third Supplemental Indenture dated as of March 21, 2000, to the Indenture dated as of May 27, 1999, (Exhibit 4.7.1 to our 2000 Second Quarter Form 10-Q); Fourth Supplemental Indenture dated as of July 11, 2000. (Exhibit 4.2.1 to our 2001 Third Quarter Form 10-Q); Fifth Supplemental Indenture dated as of August 30, 2000 (Exhibit 4.2.2 to our 2001 Third Quarter Form 10-Q); Sixth Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.1 to our 2002 First Quarter Form 10-Q); Seventh Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.2 to our 2002 First Quarter Form 10-Q); Eighth Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.D.3 to our 2002 Third Quarter Form 10-Q); Ninth Supplemental Indenture dated as of November 27, 2002 to the

Indenture dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors and JPMorgan Chase Bank, as Trustee (Exhibit 4.D.1 to our Current Report on Form 8-K dated March 19, 2003); Tenth Supplemental Indenture dated as of January 1, 2003 to the Indenture dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors and JPMorgan Chase Bank, as Trustee (Exhibit 4.D.2 to our Current Report on Form 8-K dated March 19, 2003).

EXHIBIT NUMBER DESCRIPTION - -------------------------

4.E -- Indenture dated as of May 11, 2000 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, The Subsidiary Guarantors named therein and The Chase Manhattan Bank, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.1 to our 2002 First Quarter Form 10-Q); Second Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.2 to our 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.E.3 to our 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 to the Indenture dated as of May 17, 2001 among El Paso Energy Partners, L.P., El Paso Energy Partners

Finance Corporation, The Subsidiary Guarantors and JPMorgan Chase Bank, as Trustee (Exhibit 4.E.1 to our Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 to the Indenture dated as of May 17, 2001 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, The Subsidiary Guarantors and JPMorgan Chase Bank, as Trustee (Exhibit 4.E.2 to our Current Report on Form 8-K dated March 19, 2003).

4.F -- Letter agreement dated March 5, 2002, between Crystal Gas Storage, Inc. and El Paso Energy Partners, LP (Exhibit 4.F of our 2001 Form 10-K).

4.F -- A/B Exchange Registration Rights Agreement dated as of May 17, 2002, by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the subsidiary guarantors party thereto, Credit Suisse First Boston

Corporation, Goldman, Sachs & Co., J.P. Morgan Securities Inc., Banc One Capital Markets, Inc., Fleet Securities, Inc., Fortis Investment Services L.L.C., The Royal Bank of Scotland plc, BNP Securities Corp. and First Union Securities, Inc. (Exhibit 4.3 to our Registration Statement on Form S-4 filed August 12, 2002).

4.G -- Registration Rights Agreement by and between El Paso Corporation and El Paso Energy Partners, L.P. dated as of November 27, 2002 (Exhibit 4.G to our Current Report on Form 8-K dated December 11, 2002).

4.H -- A/B Exchange Registration Rights Agreement by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors party thereto, J.P. Morgan Securities Inc., Goldman, Sachs & Co., UBS Warburg LLC and Wachovia Securities, Inc. dated as of November 27, 2002 (Exhibit 4.H to our Current

Report on Form 8-K dated December 11, 2002). 4.I -- Indenture dated as of November 27, 2002 by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (Exhibit 4.I to our Current Report on Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 to the Indenture dated as of November 27, 2002 by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, The Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (Exhibit 4.I.1 to our Current Report on Form 8-K dated March 19, 2003). 10.A -- Amended and Restated General and Administrative Services Agreement by and between DeepTech International Inc., El Paso Energy Partners Company and El Paso Field Services, L.P. dated November 27, 2002 (Exhibit 10.A to our 2002 Third Quarter Form 10-Q).

EXHIBIT NUMBER DESCRIPTION - ------------- -----------

10.B -- Sixth Amended and Restated Credit Agreement dated as of March 23, 1995, as amended and restated through October 10, 2002 by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, Credit Lyonnais New York Branch and First Union National Bank, as Co-Syndication Agents, Fleet National Bank and Fortis Capital Corp., as Co-Documentation Agents, The Chase Manhattan Bank, as Administrative Agent, and the several banks and other financial institutions signatories thereto (Exhibit 10.B to our 2002 Third Quarter Form 10-Q); First Amendment dated as of November 21, 2002 (filed as Exhibit 10.B.1 to our Current Report on Form 8-K dated March 19, 2003).

10.G -- Limited Liability Company Agreement for Poseidon Oil Pipeline Company, L.L.C. dated

February 14, 1996; First Amendment to the Limited Liability Company Agreement for Poseidon Oil Pipeline Company, L.L.C. dated February 14, 1996. (collectively attached as Exhibit 10.14 to our 2000 First Quarter Form 10-Q). 10.I -- Purchase and Sale Agreement dated as of September 27, 2001 by and between American Natural Offshore Company, Texas Offshore Pipeline System, Inc., Unitex Offshore Transmission Company and ANR Western Gulf Holdings, L.L.C. as Sellers and El Paso Energy Partners Deepwater, L.L.C., as Buyer (Exhibit 2.1 to our Report on Form 8-K dated October 25, 2001). 10.L+ -- 1998 Unit Option Plan for Non-Employee Directors Amended and Restated effective as of April 18, 2001. (Exhibit 10.1 to our 2001 Second quarter Form 10-Q). 10.M+ -- 1998 Omnibus Compensation Plan, Amended and Restated, effective as of January 1, 1999 (Exhibit 10.9 to our 1998 Form 10-K); Amendment

No. 1 dated as of December 1, 1999. (Exhibit 10.8.1 to our 2000 Second Quarter Form 10-Q). 10.N -- Purchase, Sale and Merger Agreement by and between El Paso Tennessee Pipeline Co. and El Paso Energy Partners, L.P., dated as of April 1, 2002 (Exhibit 10.N to our 2002 First Quarter Form 10-Q). 10.O -- Contribution Agreement by and between El Paso Field Services Holding Company and El Paso Energy Partners, L.P. dated as of April 1, 2002 (Exhibit 10.O to our 2002 First Quarter Form 10-Q). 10.P -- Purchase and Sale Agreement by and between El Paso Energy Partners, L.P. and El Paso Production GOM Inc. dated as of April 1, 2002 (Exhibit 10.P to our 2002 First Quarter Form 10-Q). 10.Q -- Amended and Restated Credit Agreement among EPN Holding Company, L.P., the Lenders party thereto, Banc One Capital Markets, Inc. and Wachovia Bank, N.A., as Co-Syndication Agents, Fleet National Bank and Fortis Capital Corp., as Co-Documentation Agents, and JPMorgan Chase Bank, as Administrative Agent, dated as of April 8, 2002 (Exhibit 10.Q to our 2002 Third Quarter Form 10-Q); First Amendment dated as of November 21, 2002 (filed as Exhibit 10.Q.1 to our Current Report on Form 8-K dated March 19, 2003).

10.R -- Letter Agreement by and among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors party thereto, JPMorgan Chase Bank, Goldman Sachs Credit Partners L.P., UBS AG, Stamford Branch and Wachovia Bank, National Association dated November 27, 2002 (Exhibit 10.R to our Current Report on Form 8-K dated March 19, 2003).

10.S -- Senior Secured Acquisition Term Loan Credit Agreement dated as of November 27, 2002 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance

Corporation, the Lenders party thereto, Goldman Sachs Credit Partners L.P., Documentation Agent, UBS Warburg LLC and Wachovia Bank, National Association, as Co-Syndication Agents and JPMorgan Chase Bank, as Administrative Agent (Exhibit 10.S to our Current Report on Form 8-K dated March 19, 2003).

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EXHIBIT 21

OWNERSHIP LIST
EL PASO ENERGY PARTNERS, L.P.
AS OF DECEMBER 31, 2002

% ENTITY NAME OWNER OWNERSHIP -- --------- -- --- -------- - 4 Atlantis Offshore, LLC (DE) Manta Ray Gathering Company, L.L.C. 50 Unaffiliated Parties 50 4 Crystal Holding, L.L.C. (DE) El Paso Energy Partners, L.P. 100 4 DeepTech International Inc. (DE) El Paso Corporation 100 4 Deepwater Gateway, L.L.C. (DE) EPN Field Services, L.L.C. 50 Unaffiliated Parties 50 4 El Paso Energy Intrastate, L.P. (DE) El Paso Energy Partners, L.P. (LP) 99 EPN Pipeline GP Holding, L.L.C. (GP) 1 4 El Paso Energy Partners Company (DE) DeepTech International Inc. 100 4 El Paso Energy Partners Finance Corporation (DE) El Paso Energy Partners, L.P. 100 4 El Paso Energy Partners Oil Transport, L.L.C (DE) El Paso Energy Partners, L.P. 100 4 El Paso

Energy
Partners
Operating
Company,
L.L.C. (DE)
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L.P. 100 4
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L.P. (DE) El
Paso Energy
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13.09 Sabine
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Investors I,
L.L.C. 7.01
Sabine River
Investors
II, L.L.C.
6.05 El Paso
Field
Services
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Company .36
Publicly
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Treating GP
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L.L.C. (GP)
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EPN Arizona
Gas, L.L.C.
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Services,
L.L.C. 100 4
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Services,
L.L.C. (DE)
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and Treating
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Partners Oil
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L.L.C. (GP)
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Holding I,
L.L.C. (GP)
1 EPN Gulf
Coast, L.P.
(LP) 99 4
EPN Holding
Company,

L.P. (DE)
EPN GP
Holding,
L.L.C. (GP)
1 EPN
Holding
Company I,
L.P. (LP) 99
4 EPN NGL
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L.L.C. (DE)
Crystal
Holding,
L.L.C 100 4
EPN Pipeline
GP Holding,
L.L.C. (DE)
El Paso
Energy
Partners,
L.P. 100 4
First
Reserve Gas,
L.L.C. (DE)
Crystal
Holding,
L.L.C. 100 4
Flextrend
Development
Company,
L.L.C. (DE)
El Paso
Energy
Partners,
L.P. 100 4
Hattiesburg
Gas Storage
Company (DE)
First
Reserve Gas,
L.L.C. (GP)
50
Hattiesburg
Industrial
Gas Sales,
L.L.C. (GP)
50 4
Hattiesburg
Industrial
Gas Sales,
L.L.C. (DE)
First
Reserve Gas,
L.L.C. 100 4
High Island
Offshore
System,
L.L.C. (DE)
El Paso
Energy
Partners,
L.P. 100

Structure as of December 31, 2002

% ENTITY NAME OWNER OWNERSHIP - ---------- ----- ----- ---- 4 Manta Ray Gathering Company, L.L.C. (DE) El Paso Energy Partners, L.P. 100 4 Petal Gas Storage, L.L.C. (DE) Crystal Holding, L.L.C. 100 4 Poseidon Oil Pipeline Company, L.L.C. (DE) Poseidon Pipeline Company, L.L.C. 36 Unaffiliated Parties 64 4 Poseidon Pipeline Company, L.L.C. (DE) El Paso Energy Partners, L.P. 100 4 Warwink Gathering & Treating Company (TX) El Paso Energy Warwink I Company, L.P. 50 (General Partnership) El Paso Energy Warwink II Company, L.P. 50 Arizona Gas Storage, L.L.C. EPN Arizona Gas, L.L.C. 60 Unaffiliated Parties 40 Copper Eagle Gas Storage, L.L.C. Arizona Gas Storage, L.L.C. 50 Unaffiliated Parties 50 Chaco Liquids Plant Trust EPN Field Services, L.L.C. 100

EXHIBIT 23a

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-81772) of El Paso Energy Partners, L.P. (the "Partnership") of (i) our report dated March 24, 2003 relating to the consolidated financial statements and the financial statement schedule of the Partnership and subsidiaries which appears in this Form 10-K. We also consent to the incorporation by reference of our report dated March 24, 2003 relating to the financial statements of Poseidon Oil Pipeline Company, L.L.C., which appears in this Form 10-K.

/s/ PRICEWATERHOUSECOOPERS, L.L.P.

Houston, Texas
March 27, 2003

Exhibit 23.B

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference to our reserve reports dated as of December 31, 2002, 2001, and 2000, each of which is included in the Annual Report on Form 10-K of El Paso Energy Partners, L.P. for the year ended December 31, 2002.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ FREDERIC D. SEWELL

Frederic D. Sewell
Chairman and Chief Executive Officer

Dallas, Texas
March 27, 2003

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K for the period ending December 31, 2002, of El Paso Energy Partners, L.P. (the "Company") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert G. Phillips, Chairman of the Board and Chief Executive Officer, certify (i) that the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert G. Phillips

Robert G. Phillips
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)
El Paso Energy Partners Company, general
partner of El Paso Energy Partners, L. P.

March 27, 2003

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K for the period ending December 31, 2002, of El Paso Energy Partners, L.P. (the "Company") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Keith B. Forman, Vice President and Chief Financial Officer, certify (i) that the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Keith B. Forman

Keith B. Forman
Vice President and
Chief Financial Officer
(Principal Financial Officer)
El Paso Energy Partners Company, general
partner of El Paso Energy Partners, L. P.

March 27, 2003

EXHIBIT 99.C

EL PASO ENERGY PARTNERS COMPANY
AUDIT AND CONFLICTS COMMITTEE CHARTER

OBJECTIVES

The Audit and Conflicts Committee is a committee of the Board of Directors of El Paso Energy Partners Company, as General Partner of El Paso Energy Partners, L.P. (the "Partnership"). Its primary function is to assist the Board in fulfilling its oversight responsibilities to ensure the integrity of the Partnership's financial statements, the Partnership's compliance with legal and regulatory requirements, the independent auditor's qualifications, independence and performance and the performance of the Partnership's internal audit functions. The Audit and Conflicts Committee provides an open avenue of communication between the internal auditors, the independent accountants, and the Board of Directors. The Audit and Conflicts Committee also will, at the request of the Board of Directors, review potential conflicts of interest that may arise between the Partnership and its affiliates to determine if the proposed resolution of such potential conflict is fair and reasonable to the Partnership.

MEMBERSHIP AND POLICIES

- The Audit and Conflicts Committee shall be composed of not less than three "independent" (as such term is defined pursuant to Section 10A of the Securities Exchange Act of 1934, and the rules adopted by the New York Stock Exchange) members of the Board. The Board shall elect the Audit and Conflicts Committee Chairman.

- Each member of the Audit and Conflicts Committee shall be financially literate, as such qualification is interpreted by the Board of Directors in its business judgment, or must become financially literate within a reasonable period of time after his or her appointment to the Audit and Conflicts Committee.

- Subject to any phase-in period adopted by the Securities and Exchange Commission ("SEC"), at least one member of the Audit and Conflicts Committee shall be a "financial expert," as such term is defined in rules adopted by the SEC and interpreted by the Board in its business judgment; provided, however, that if at least one member of the Audit Committee is not determined by the Board to be a "financial expert," then the Partnership shall disclose such determination as required by applicable SEC rules.

- The Audit and Conflicts Committee shall have the authority to engage independent counsel and other advisers, as it determines necessary to carry out its duties. Such engagement shall not require approval of the entire Board. The Partnership shall provide appropriate funding for independent counsel and other advisers retained by the Audit Committee.

- The Audit and Conflicts Committee shall meet a minimum of four times per calendar year or more frequently as circumstances require.

- The Audit and Conflicts Committee may designate a subcommittee consisting of at least one member to address specific issues on behalf of the Committee.

- The Audit and Conflicts Committee shall report periodically to the Board on its activities.

EFFECTIVE 1-21-03

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FUNCTIONS

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A. INDEPENDENT AUDITOR

- The Audit and Conflicts Committee shall be directly responsible for the appointment, termination, compensation and oversight of the work of the independent auditing firm employed by the Partnership (including resolution of disputes between management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work, and the independent auditor shall report directly to the Audit and Conflicts Committee. All auditing services and permitted non-audit services provided to the Partnership by the independent auditor shall be pre-approved by the Committee in accordance with applicable law. These responsibilities do not preclude the Committee from obtaining the input of management, but these responsibilities may not be delegated to management.

- The Audit and Conflicts Committee shall evaluate, at least annually, the auditor's qualifications, performance and independence. In connection with such evaluation, the Committee shall obtain and review a formal written report by the independent auditors which (a) describes the audit firm's internal quality control procedures, (b) describes any material issues raised by the most recent internal quality control review or peer review of the auditing firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, with respect to one or more independent audits carried out by the auditing firm and steps taken to address the issues, and (c) delineates all relationships between the independent auditors and the Partnership in order to assess the auditor's independence. The Audit and Conflicts Committee shall also review and evaluate the lead partner of the independent auditor. In making its evaluations, the Committee shall consult with and take into consideration the opinions of management and the Partnership's internal auditors. The Committee shall present its conclusions with respect to the independent auditor to the Board.

- In addition to assuring the regular rotation of audit partners as required by law, the Audit and Conflicts Committee shall consider whether, in order to ensure continuing auditor independence, there should be regular rotation of the audit firm itself.

- The Audit and Conflicts Committee shall set clear hiring policies for employees or former employees of the independent auditor in compliance with applicable law. At a minimum, the Committee will adopt hiring policies in compliance with Section 10A(l) of the Securities Exchange Act of 1934.

B. OVERSIGHT OF FINANCIAL STATEMENTS

- The Audit and Conflicts Committee shall meet with management and the independent auditor to discuss the annual and quarterly financial statements (including the Management Discussion and Analysis of Financial Condition and Results of Operations), and other filings with the Securities and Exchange Commission as necessary.

- The Audit and Conflicts Committee shall discuss the types of information to be disclosed, and the type of presentation to be made, with regard to earnings press releases and financial information and earnings guidance given to analysts and rating agencies with a special emphasis on reviewing pro forma or adjusted non-GAAP data.

- The Audit and Conflicts Committee shall meet with management to discuss risk assessment, risk management guidelines and policies and the Partnership's significant financial risk exposures, as well as the steps management has taken to monitor and control these exposures. By such review, the Committee does not assume responsibility for risk management.

- The Audit and Conflicts Committee shall meet, at least once a quarter, with management, the head of internal audit and the lead partner of the independent auditor in separate executive sessions.

- The Audit and Conflicts Committee shall review with the controller and the independent auditor any changes in accounting policies as well as any other significant financial reporting issues.

- The Audit and Conflicts Committee shall review with the independent auditors (a) plans, staffing and scope for the each annual audit, (b) the results of the annual audit and resulting opinion (including major issues regarding accounting and auditing principles and practices), and (c) the adequacy of the Partnership's internal controls.

- The Audit and Conflicts Committee shall review with the independent auditors any audit problems or difficulties and management's responses, including (a) accounting adjustments that the auditors noted or proposed but were "passed" (as immaterial or otherwise), (b) any significant disagreements with management, (c) any restrictions on the scope of activities or access to information, (d) communications between the audit team and its national office with respect to issues presented by the engagement team, and (e) any management or internal control letter issued or proposed to be issued by the audit firm to the Partnership. This review shall also include discussion of the responsibilities, budget and staffing of the Partnership's internal audit functions.

- The Audit and Conflicts Committee shall take reasonable steps to ensure that management follows the Partnership's disclosure controls and procedures and conducts appropriate due diligence to support the integrity of the financial information.

- The Audit and Conflicts Committee shall establish and maintain procedures for (a) the receipt, retention and treatment of complaints received by the Partnership regarding accounting, internal accounting controls or auditing matters, and (b) the confidential, anonymous submission by employees of the Partnership of concerns regarding questionable accounting our auditing matters.

- The Audit and Conflicts Committee shall review with management and the independent auditor any correspondence with regulators or governmental agencies and any employee complaints or published reports which raise material issues regarding the Partnership's financial statements or accounting policies.

- The Audit and Conflicts Committee shall review with the Partnership's general counsel legal matters that may have a material impact on the financial statements, the Partnership's compliance policies and any material reports or inquiries received from regulators or governmental agencies.

- The Audit and Conflicts Committee shall prepare the report for inclusion in the Partnership's annual report, in accordance with applicable rules and regulations of the Securities and Exchange Commission.

C. INTERNAL AUDIT

- The Audit and Conflicts Committee shall ensure that the Partnership establishes and maintains an internal audit function as required by the New York Stock Exchange.

- The Audit and Conflicts Committee shall participate in the selection or removal of the head of internal audit.

- The Audit and Conflicts Committee shall review with the head of internal audit: (a) audit plans and scope for internal audit activities, (b) results of audits performed, (c) adequacy of the Partnership's internal controls, (d) compliance with the Partnership's Code of Business Conduct, and (e) the internal audit department charter.

- The Audit and Conflicts Committee shall review with the head of internal audit and the independent auditor the coordination of the audit effort to ensure completeness of coverage, reduction of redundant efforts, and the effective use of audit resources.

- The Audit and Conflicts Committee shall meet, or a quarterly basis, with the head of internal audit, the independent auditor and management to discuss (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Partnership's ability to record, process, summarize, and report financial data, and any material weakness in internal controls, and (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Partnership's internal controls.

D. OTHER DUTIES AND FUNCTIONS

- The Audit and Conflicts Committee shall review and reassess the adequacy of this charter periodically.

- The Audit and Conflicts Committee shall conduct an annual performance evaluation in accordance with the rules adopted by the New York Stock Exchange.

- The Audit and Conflicts Committee will perform such other functions as assigned by law, the Partnership's organizational documents, or the Board of Directors.

- While the Audit and Conflicts Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit Committee to conduct audits or to determine that the Partnership's financial statements are complete and accurate and are in accordance with GAAP. This is the responsibility of management and the independent auditor.

EL PASO ENERGY PARTNERS COMPANY
GOVERNANCE AND COMPENSATION COMMITTEE CHARTER

OBJECTIVES

The Governance and Compensation Committee is a committee of the Board of Directors of El Paso Energy Partners Company, as General Partner of El Paso Energy Partners, L.P. (the "Partnership"). The Committee shall develop and recommend to the Board a set of governance principles applicable to the Partnership, review the qualifications of candidates for Board membership, screen and interview possible candidates for Board membership and communicate with members of the Board regarding Board meeting format and procedures. The Committee shall also review the executive compensation program of the Partnership to ensure that it is adequate to attract, motivate and retain competent executive personnel and that it is directly and materially related to the short-term and long-term objectives and operating performance of the Partnership.

MEMBERSHIP AND POLICIES

- The Board of Directors shall appoint the Chairperson and members of the Committee annually. The Committee shall consist of a minimum of two members of the Board. Each member of the Committee shall be "independent" as defined under the rules adopted by the New York Stock Exchange. Members of the Committee may be removed from the Committee by action of the full Board.

- The Committee shall meet at such times as the Chairperson shall determine, preferably in conjunction with regular Board meetings. Meetings may, at the discretion of the Committee, include members of management, independent consultants and such other persons as the Committee shall determine. The Committee, in discharging its responsibilities, may meet privately for advice and counsel with independent consultants, lawyers, or any other persons knowledgeable in the matters under consideration. The Committee may also meet by telephone conference call or any other means permitted by law or the organizational documents of the general partner.

- A Secretary, who need not be a member of the Committee, shall be appointed by the Committee to keep minutes of all meetings of the Committee and such other records as the Chairperson deems necessary or appropriate.

- The Committee may designate a subcommittee consisting of at least one member to address specific issues on behalf of the Committee.

- The Committee shall report periodically to the Board on its activities.

GOVERNANCE FUNCTIONS

- The Committee shall develop and recommend to the Board a set of governance guidelines applicable to the Partnership, and, as appropriate, recommend to the Board certain criteria (in addition to those criterion required by applicable law) to determine a director's independence.

- The Committee shall monitor the size and composition of the Board. Subject to actions by the Board, the Committee shall assure that the composition of the Board of Directors and any committees thereof, complies with the rules adopted by the New York Stock Exchange and other applicable laws.

Effective: January 21, 2003

- The Committee shall review qualifications of candidates for Board membership recommended by Directors, officers, employees and others in accordance with procedures established by the Partnership's governance guidelines, applicable laws and regulations, and the Committee.

- The Committee shall screen and interview possible qualified candidates for Board membership and aid the Chairman of the Board in attracting qualified candidates, as the Chairman may request.

- The Committee has the ultimate authority and responsibility to select, evaluate and, where appropriate, replace any search firm to be used to identify qualified director candidates, including the sole authority to approve the search firm's fees and other retention terms.

- The Committee shall develop and recommend to the Board a policy on potential conflicts of interest, including, but not limited to, the policies on (1) loans to officers and employees (if allowed by law), (2) related-party transactions (including any dealings with directors, officers or employees), and (3) such other transactions that could have the appearance of a potential conflict of interest.

- The Committee shall monitor and report to the Board whether there is any current relationship between any non-management director and the Partnership that may adversely affect the independent judgment of the Director.

- The Committee shall communicate, from time to time, with members of the Board regarding Board meeting format and procedures.

- The Committee shall review the need for any changes in the number, charters, or titles of Board committees and provide a recommendation to the Board for consideration.

- The Committee will (i) oversee the annual performance evaluation of the Board, (ii) conduct an annual performance evaluation of the Committee, the results of which shall be reported to the full Board, and (iii) ensure that the chairperson of each other Board committee conducts a performance evaluation of his or her committee, the results of which shall be reported to the full Board.

- The Committee shall take such other actions necessary or appropriate to assure that other activities prescribed by the governance guidelines are carried out.

COMPENSATION FUNCTIONS

- The Committee shall periodically review and approve the Partnership's stated compensation strategy to ensure that management is rewarded appropriately for its contributions to Partnership growth and profitability and that the executive compensation strategy supports organization objectives.

- The Committee shall ensure the executive compensation program of the Partnership is directly related to the Partnership's financial performance, and the performance of the individual executive officer.

- The Committee shall review appropriate criteria for establishing performance targets and determining annual organization and executive performance ratings.

- The Committee shall determine appropriate levels of executive compensation by periodically conducting a thorough competitive evaluation, reviewing proprietary and proxy information, and consulting with and receiving advice from an independent executive compensation consulting firm. The Committee has the ultimate authority and responsibility to select, evaluate and, where appropriate, replace such independent executive compensation consulting firm, including the sole authority to approve the firm's fees and other retention terms.

- The Committee shall ensure that the Partnership's executive compensation plans are administered in accordance with stated compensation objectives, and shall make recommendations to the Board of Directors with respect to such plans.

- The Committee shall review the Partnership's employee benefit and compensation programs and approve management recommendations subject, where appropriate, to Board of Director approval.

- The Committee shall consider proposals with respect to the creation of and changes to the Partnership's executive compensation program.

- In consultation with the Compensation Committee of El Paso Corporation, the Committee shall review annually and approve the individual elements of total compensation for the Chief Executive Officer and other executive officers of the Partnership and prepare a report on the factors and criteria on which their compensation was based, including the relationship of the Partnership's performance to their compensation.

- The Committee shall periodically review and make recommendation to the full Board regarding annual retainer and meeting fees for the Board of Directors and committees of the Board and shall propose the terms and awards of equity compensation for members of the Board, provided that any such recommendations and proposals shall be made in consultation with the Governance Committee.

OTHER FUNCTIONS

- The Committee shall review and assess the adequacy of this charter periodically.

- The Committee will perform such other functions as assigned by law, the Partnership's organizational documents, or the Board.