UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2001

OR

**o
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.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (Zip Code)

Registrant's telephone number, including area code: (713) 420-2600

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 ☑ No o

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. o

The registrant had 39,738,974 common units outstanding as of February 27, 2002. The aggregate market value on such date of the registrant's common units held by non-affiliates was approximately $1,393 million.

Documents Incorporated by Reference: None

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 in terms of market capitalization. We currently manage a balanced, diversified portfolio of interests and assets that includes:

- oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure assets in the deeper water regions of the Gulf of Mexico, primarily offshore Louisiana and Texas;
- intrastate natural gas pipeline assets in Alabama;
- Natural gas liquids (NGL) transportation and fractionation facilities in south Texas;
- natural gas processing facilities in New Mexico;
- natural gas and NGL storage facilities in Mississippi and Louisiana; and
- oil and natural gas properties in the Gulf of Mexico.

Our objective is to operate as a growth-oriented master limited partnership with a focus on increasing our cash flow, earnings and return to our unitholders. Our strategy is to combine our position as a provider of midstream services in the deeper water regions of the Gulf of Mexico with an aggressive effort to acquire and develop diversified onshore midstream energy infrastructure assets. Our strategy also includes identifying opportunities that create synergies with the other assets and operations of El Paso Corporation, the indirect parent of our general partner. We intend to continue de-emphasizing our commodity-based activities, such as exploration and production operations, and to concentrate on fee-based operations, such as gathering, transportation, processing, storage and fractionation, which traditionally provide more stable cash flows. We intend to execute our business strategy by:

- capitalizing on our extensive infrastructure in the Gulf of Mexico and expanding our existing assets further into the deeper water regions with projects supported by new discoveries and long-term commitments;
- purchasing or constructing onshore pipelines, gathering systems, storage, 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; and
- leveraging the nationwide asset base and operational expertise of El Paso Corporation.

We regularly consider and enter into discussions regarding potential acquisitions, including those from El Paso Corporation or its subsidiaries, and expect to continue to do so in the future. In 2001, our cash outlay for investments of midstream energy infrastructure assets totaled $589 million. Assets acquired from El Paso Corporation and third parties totaled $344 million and $78 million, and funds expended for the construction of assets totaled $167 million.

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.

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

- the 9,400 mile EPGT Texas intrastate pipeline, with a capacity of approximately 5 Bcf/d and average throughput of 3,500 MDth/d during 2001;
- 1,300 miles of gathering systems in the Permian Basin with a capacity of 465 MMcf/d and average net 2001 throughput of 341 MDth/d; and
- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

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

- the sale of our Prince tension leg platform (TLP) and the 9 percent overriding royalty interest in the Prince Field for approximately $190 million after our repayment of the related limited recourse debt of $95 million;
- the issuance of $6 million in common units; and
- a cash payment of $554 million.

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

Also in February 2002, we announced that we will build and operate the Cameron Highway Oil Pipeline System, a 380-mile oil pipeline in the Gulf of Mexico. Cameron Highway will deliver up to 500 MBbl/d of oil from the southern Green Canyon and western Gulf of Mexico areas to Port Arthur and Texas City, Texas. The new pipeline is expected to be in service by the third quarter of 2004. We have entered into agreements with operating subsidiaries of BP p.l.c., BHP Billiton, and Unocal under which each of them have dedicated production from the Holstein, Mad Dog, and Atlantis Deepwater Trend discoveries for transportation on Cameron Highway. We will seek a partner or partners for up to 50 percent of the interest in the pipeline.

In January 2002, we acquired a 3.3 million barrel propane storage business and complete leaching operation located in Hattiesburg, Mississippi from Suburban Propane Partners, L.P. As part of the transaction, we entered into a long-term propane storage agreement with Suburban Propane Partners for a portion of the acquired propane storage capacity. We intend to convert a portion of these assets to natural gas storage and will integrate them with our adjacent Petal natural gas storage facility. In December 2001, we acquired Anse La Butte, a 3.2 million barrel NGL multi-product storage facility near Breaux Bridge, Louisiana. We entered into long-term storage agreements with a third party and a subsidiary of El Paso Corporation for a significant portion of the storage capacity.

Also in December 2001, we announced an agreement with Anadarko Petroleum Corporation to jointly develop Anadarko's Marco Polo discovery, using a floating production platform capable of accommodating production from multiple fields. In conjunction with this agreement, we formed a 50/50 joint venture to construct, install, and own the platform with Cal Dive International, Inc. The platform's production capacity is expected to be 100 MBbls/d of oil and 250 Mcf/d of gas. Anadarko will have firm capacity of 50 MBbls/d of oil and 150 Mcf/d of 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. Anadarko will operate the platform. We anticipate that the facilities will be completed in 2004.

In October 2001, we acquired interests in the titleholder of, and other interests in, the Chaco cryogenic natural gas processing plant, the third 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. It is capable of processing up to 700 Mdth/d of natural gas and handling up to 50 MBbls/d of NGLs.

In conjunction with this transaction, we also acquired the remaining 50 percent equity interest that we did not already own in Deepwater Holdings from a subsidiary of El Paso Corporation. As a result, the High Island Offshore System (HIOS) and the East Breaks natural gas gathering system (East Breaks) became indirect wholly-owned assets.

Also in October 2001, we agreed to install a new natural gas pipeline from our Viosca Knoll system to the deepwater Medusa development in the Gulf of Mexico. We also entered into an agreement to provide natural gas gathering services for Murphy Exploration and Production Company's Medusa development. Construction of this pipeline is scheduled to begin in mid-2002, and first production from the Medusa development is anticipated by the fourth quarter of 2002. We also entered into an agreement to provide natural gas gathering services for TotalFinaElf's Matterhorn, Camden Hills and Aconcagua discoveries located in the Gulf of Mexico Deepwater Trend. Natural gas production from these fields will be delivered to our Viosca Knoll system. First production from Camden Hills and Aconcagua is anticipated in the summer of 2002. First production from Matterhorn is anticipated in the third quarter of 2003.

In February 2001, we acquired the south Texas fee-based NGL transportation and fractionation assets (EPN Texas) from a subsidiary of El Paso Corporation. These assets include more than 600 miles of NGL gathering and transportation pipelines, as well as three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGLs into ethane, propane and butane products, which are used by refineries and petrochemical plants along the Texas Gulf Coast.

In January 2001, we agreed to sell our interests in several offshore Gulf of Mexico assets, including our interests in the Nautilus, Manta Ray Offshore, Nemo, Green Canyon and Tarpon natural gas pipeline systems, as well as interests in two offshore platforms. In addition, we and Deepwater Holdings agreed to sell our joint interests in the Stingray System, UT Offshore System (UTOS), and the West Cameron dehydration facility. These sales occurred as a result of a Federal Trade Commission (FTC) order relating to El Paso Corporation's merger with The Coastal Corporation.

Segments

We segregate our business activities into five segments:

- Natural Gas Gathering and Transportation;
- Liquid Transportation and Handling;
- Platforms;
- Natural Gas Storage; and
- Oil and Natural Gas Production.

These segments are strategic business units that provide a variety of energy related services. For information relating to operating revenues and operating income of each segment, see Item 8, Financial Statements and Supplementary Data, Note 13. Each of these segments is discussed more fully below.

Natural Gas Gathering and Transportation

Our pipeline systems extend over 870 miles and have a combined maximum design capacity of over 3.4 Bcf/d of natural gas. 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. In addition to our offshore natural gas pipeline systems, we have a gathering system that serves the coal bed methane producing regions of Alabama and a small pipeline lateral in New Mexico. The following table and discussions describe our natural gas pipelines, all of which we wholly-own and operate.

	Viosca Knoll	HIOS[1]	East Breaks[1]	El Paso Intrastate-Alabama	Indian Basin
Unregulated(U)/ regulated(R)	U	R	U	U	U
In-service date	1994	1977	2000	1972	2001
Approximate capacity[2]	1,000	1,800	400	200	65
Aggregate miles of pipeline	125	204	85	450	10
Average throughput for the years ended:[3]					
December 31, 2001	551	979	245	171	22
December 31, 2000	612	870	112	120	—
December 31, 1999	709	792	—	—	—

(1) The average throughput reflects 100 percent of the throughput. Prior to October 2001, we owned a 50 percent interest in HIOS and East Breaks through Deepwater Holdings. We acquired the remaining 50 percent interest in October 2001 from subsidiaries of El Paso Corporation.
(2) All capacity measures are on a MMcf/d basis.
(3) All average throughput measures are on a MDth/d basis. For the pipelines described above, one MDth is substantially equivalent to one MMcf.

Viosca Knoll System. The Viosca Knoll system is an offshore natural gas gathering system designed to serve the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico and consists of 125 miles of predominantly 20-inch natural gas pipeline and a 7,000 horsepower compressor. During 1999, we acquired an additional 49 percent interest in the Viosca Knoll system, and in 2000 we acquired the remaining one percent from a subsidiary of El Paso Corporation, bringing our total interest in the Viosca Knoll system to 100 percent. The system provides its customers access to 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.

HIOS. In October 2001, HIOS became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings that we did not already own from subsidiaries of El Paso Corporation. HIOS is a natural gas transmission system regulated by the Federal Energy Regulatory Commission (FERC), that consists of 204 miles of pipeline. HIOS 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. In October 2001, East Breaks became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings that we did not already own from subsidiaries of El Paso Corporation. East Breaks is a natural gas gathering system that consists of an 85-mile pipeline that 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 was placed in service in June 2000 and 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.

El Paso Intrastate-Alabama System. In March 2000, we acquired the EPIA system, a natural gas pipeline system that serves the coal bed methane producing regions of Alabama. The system consists of over 450 miles of pipeline. EPIA also provides marketing services through the purchase and resale of natural gas by purchasing natural gas from regional producers and others, and selling natural gas to local distribution companies and others.

Indian Basin. The Indian Basin lateral, located in southeast New Mexico, was placed into service in June 2001. This ten mile lateral connects the 300 MMcf/d Indian Basin processing and treating plant to El Paso Field Services' Carlsbad Gathering System. The lateral offers alternative market outlets to the Transwestern and El Paso Natural Gas pipeline systems.

Markets and Competition

Each of our natural gas pipeline systems are located at or near natural gas production areas that are served by other pipelines. Our natural gas pipeline systems 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. Other competing pipelines, such as long-haul transporters, may have rate design alternatives unavailable to ours. Consequently, those competing pipelines may be able to provide service on more flexible terms and at rates significantly below those we offer.

A majority of the revenues generated by our pipeline systems are attributed to production from reserves committed under long-term contracts for the productive life of the relevant field. 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. 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. A majority of our offshore arrangements involve life-of-reserve commitments with both firm and interruptible components. Generally, we receive a price per dekatherm of natural gas handled.

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. All of our pipeline systems are subject to the National Environmental Policy Act and other environmental legislation. Each of the pipeline systems has a continuing program of inspection designed to keep all of our facilities in compliance with pollution control and pipeline safety requirements. We believe that our pipeline systems are in compliance with the applicable requirements of these regulations.

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

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 moisture or sea water. Our HIOS and Viosca Knoll systems include platforms that are manned on a continuous basis. The personnel onboard 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.

Liquid Transportation and Handling

NGL Transportation and Fractionation Facilities

In February 2001, we acquired EPN Texas from a subsidiary of El Paso Corporation. EPN Texas includes more than 600 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 NGLs from various processing plants to the Shoup Plant, located in Corpus Christi, the largest of EPN Texas' three fractionators. The system also includes 177 miles of pipelines that deliver fractionated products such as ethane, propane and butane 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. The average annual utilization rate of the fractionation facilities for 2001, 2000, and 1999 was 73 percent, 89 percent, and 88 percent. We secured a commitment from a subsidiary of El Paso Corporation that the utilization rate of these facilities during 2001 would be at least 85 percent. This commitment expired on December 31, 2001.

Natural Gas Processing Facility

In October 2001, we acquired interests in the titleholder of, and other interests in, the Chaco cryogenic natural gas processing plant, the third 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 700 MDth/d of natural gas and handling up to 50 MBbls/d of NGLs. The average utilization rate for the Chaco plant for the calendar years 2001, 2000, and 1999 was 89 percent, 91 percent, and 93 percent. The average utilization rate from our acquisition date of October 18, 2001 to December 31, 2001, was 93 percent.

Offshore Oil Pipeline Systems

We have interests in two offshore oil pipeline systems, which extend over 300 miles and have a combined capacity of 480 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 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.

Poseidon System. Poseidon is a major offshore sour crude oil pipeline system built in response to the increased demand for additional sour crude oil pipeline capacity in the central Gulf of Mexico. We own an effective 36 percent interest in Poseidon and began operating this system in January 2001. Poseidon has a maximum design capacity of 400 MBbls/d with the addition of pumps and the use of friction reducers. Our average net throughput was 56 MBbls/d, 57 MBbls/d, and 61 MBbls/d for the years ended December 31, 2001, 2000 and 1999. The Poseidon system consists of:

- 117 miles of 16-inch 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.

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. Allegheny has an approximate capacity of 80 MBbls/d and our average throughput was 13 MBbls/d, 18 MBbls/d, and 12 MBbls/d for the years ended December 31, 2001, 2000 and 1999. Oil production from the Allegheny field is committed to this system. The Allegheny system was placed into service in October 1999.

Markets and Competition

Utilization of our processing and fractionation facilities occurs only when the producer can receive more net proceeds by physically separating and selling the NGL components contained in the raw natural gas stream than they would receive by merely selling the raw natural gas stream. The spread between the prices for natural gas and NGLs is greatest when the demand for NGLs increases, which often occurs in the winter. If, and when, this spread becomes too narrow to justify the costs, producers will choose to sell the raw natural gas stream rather than process and fractionate, and our fractionation facilities will be underutilized.

In connection with our acquisition of EPN Texas, 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 this agreement, all of the NGLs 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 NGLs 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 NGLs.

In connection with the Chaco transaction, we entered into a 20-year fee-based processing agreement with El Paso Field Services. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. They have the right to purchase the Chaco Plant at the end of the lease term in October 2002 for approximately $77 million. If El Paso Field Services does not exercise this repurchase right, it must pay us a forfeiture penalty. If El Paso Field Services does exercise this repurchase right, our rights and obligations under the 20-year agreement, including our right to a fixed fee for each dekatherm of natural gas processed at the Chaco plant will remain in place for the term of the agreement and will expire upon the termination of the agreement.

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 pipelines systems are attributed to production from reserves committed under long-term contracts for the productive life of the relevant field. 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. Furthermore, 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. A majority of our offshore arrangements involve life-of-reserve commitments with both firm and interruptible components. Generally, we receive a price per barrel of oil or water handled.

Regulatory Environment

Our offshore oil 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. All of our oil pipeline systems are subject to the National Environmental Policy Act and other environmental legislation. Each of the oil pipeline systems has a continuing program of inspection designed to keep all of our facilities in compliance with pollution control and pipeline safety requirements. We believe that our oil pipeline systems are in compliance with the applicable requirements of these regulations.

Maintenance

Each of our pipeline systems, our fractionation facilities and our processing facilities require regular maintenance. The interior of the EPN Texas, Allegheny and Poseidon 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. 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. Our Chaco processing facility is manned on a continuous basis by personnel who are also responsible for maintenance and operations. The maintenance of the facility is an ongoing process, which is performed based on the hours of operation, oil analysis and vibration hours. Shutdown of the Chaco plant is not required for regular maintenance activity.

Platforms

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 platforms in the Gulf of Mexico, including five multi-purpose hub-platforms and one multi-purpose TLP in the Prince Field, which was installed in July 2001 and accepted initial production in September 2001. 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 and attract new volumes into our offshore pipeline systems. The following table and discussions describe our platforms.

	Prince TLP	East Cameron 373	Viosca Knoll 817	Ship Shoal 331(1)	Garden Banks 72	Ship Shoal 332(2)
Ownership interest	100%	100%	100%	100%	50%	50%
In-service date	2001	1998	1995	1994	1995	1985
Water depth (in feet)	1,450	441	671	376	518	438
Acquired (A) or constructed (C)	C	C	C	A	C	A
Approximate handling capacity:						
Natural gas (MMcf/d)	80	110	140	—	80	150
Oil and condensate (MBbls/d)	50	5	5	—	55	12

(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.

Prince TLP. In July 2001, we placed in service our newly-constructed Prince TLP. The Prince TLP has a state-of-the-art design, which accommodates a workover rig and four to five wellhead connections above sea level and up to three subsea wellhead connections. El Paso Production, a subsidiary of El Paso Corporation, has committed all of the oil and natural gas it produces from the Prince Field to our Prince TLP and related pipelines and separating and handling facilities, for which we receive a fixed monthly demand charge as well as a commodity charge for the volumes of natural gas, oil and water produced from the Prince Field. The Prince TLP has the capacity to accommodate a 1,200-horsepower completion rig. The deck is equipped for the future addition of numerous subsea well tie-backs. First production flowed through the Prince TLP in September 2001. As part of our pending agreement to acquire assets from El Paso Corporation in the first quarter of 2002, we agreed to sell the Prince TLP to a subsidiary of El Paso Corporation.

East Cameron 373. The East Cameron 373 platform is located at the south end of the central leg of Shell's Stingray pipeline 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 and 200 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.

Ship Shoal 331. The Ship Shoal 331 platform is a production facility located approximately 75 miles off the coast of Louisiana. Pogo Producing Company 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 pipeline system and serves as the westernmost termination point of the Poseidon system. The platform serves as a base for landing deepwater production from Enterprise Oil Gulf of Mexico, Inc.'s and Devon Energy Inc.'s Garden Banks Block 161 development and Mariner Energy Inc.'s development in Garden Banks Block 73, and will serve as the host for Amerada Hess Corporation's Garden Banks Block 158 development. 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 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.

Markets and Competition

Our platforms are subject to similar competitive factors as our natural gas and oil 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.

Natural Gas Storage

We own the Crystal salt dome natural gas storage businesses located in Mississippi, which are strategically situated to serve the Northeast, Mid-Atlantic and Southeast natural gas markets. The two primary facilities, Petal and Hattiesburg, have a combined current working capacity of 6.7 Bcf, and are capable of delivering in excess of 670 MMcf/d of natural gas into three interstate pipeline systems: Gulf South Pipeline, Transco, and Tennessee Gas Pipeline. Each of these facilities is capable of making deliveries at the high rates necessary to satisfy peaking requirements in the electric generation industry.

The Hattiesburg facility is comprised of 73 acres outside of Hattiesburg, Mississippi, and consists of three salt caverns with a working gas capacity of approximately 3.5 Bcf. The Petal facility is comprised of 16.5 acres, is less than one mile from the Hattiesburg facility and consists of a single high-deliverability natural gas storage cavern with a working gas capacity of approximately 3.2 Bcf. The Petal facility is designed to provide up to 320 MMcf/d of 10-day storage services with the capability of being refilled in 20 days. The Petal capacity is currently fully subscribed, primarily with short-term contracts. The Hattiesburg facility has an injection capacity in excess of 175 MMcf/d of natural gas and a withdrawal capacity in excess of 350 MMcf/d of natural gas. The Hattiesburg capacity is currently fully subscribed, primarily with long-term contracts expiring between 2005 and 2006. The ability of these facilities to handle 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 price savings in natural gas by allowing for quick delivery. 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.

The FERC has approved a 6.8 Bcf expansion of the Petal facility, as well as a 60-mile pipeline addition that will interconnect with the storage facility and offer direct interconnects with the Southern Natural Gas, Transco and Destin pipeline systems. The additional Petal capacity is 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. We expect to complete the first-phase of the Petal facility expansion and the construction of the pipeline addition in mid-2002.

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 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, the proposed expansion of our operations 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.

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

Oil and Natural Gas Production

Currently, we own interests in six 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 is sold to various third parties and subsidiaries of El Paso Corporation.

Producing Properties

	Garden Banks Block 72	Garden Banks Block 73(1)	Garden Banks Block 117	Viosca Knoll Block 817(2)	West Delta Block 35(3)	Prince Field(4)
Working interest	50%	—	50%	100%	38%	—
Net revenue interest	40.2%	2.5%	37.5%	80%	29.8%	9.0%
In-service date	1996	2000	1996	1995	1993	2001
Net acres	2,880	—	2,880	5,760	1,894	—
Distance offshore (in miles)	120	115	120	40	10	120
Water depth (in feet)	518	743	1,000	671	60	1,450
Producing wells	5	1	2	7	3	2
Cumulative production:						
Natural gas (MMcf)	4,565	219	2,056	61,589	2,174	32
Oil (MBbls)	1,387	—	1,146	142	14	37

(1) We own a 2.5 percent overriding interest in Garden Banks Block 73, which began producing in mid 2000.

(2) Our 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, 2001, the unpaid portion of the production payment obligation totaled $9.4 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.

(4) We own a 9 percent net overriding royalty interest in the Prince Field.

We currently own a 9 percent net overriding royalty interest in the Prince Field, formerly the Ewing Bank 958 Unit. Production from the Prince Field, which is committed to our Prince TLP, commenced in September 2001. As part of our pending agreement to acquire assets from El Paso Corporation in the first quarter of 2002, we agreed to sell this overriding royalty interest to a subsidiary of El Paso Corporation.

Acreage and Wells. The following table sets forth our developed and undeveloped oil and natural gas acreage as of December 31, 2001. 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, 2001, 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 do not intend to drill any development or exploratory wells in the future.

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)		
	2001	2000	1999	2001	2000	1999
Net production(1)	343	295	357	4,038	7,185	12,211
Average realized sales price(1)	$23.47	$25.26	$14.32	$ 4.52	$ 1.86	$ 2.02
Average realized production costs(2)	$ 7.59	$ 7.82	$ 2.38	$ 1.26	$ 1.30	$ 0.40

(1) The information regarding net production and average realized sales prices includes overriding royalty interests. Average realized oil and natural gas sales prices for 2000 and 1999 were impacted by hedging activities.

(2) The components of average production costs, which consist of operating expenses per unit of oil or natural gas produced, may vary substantially among wells depending on the methods of recovery employed and other factors, but generally include third party transportation expenses, maintenance and repair, labor and utilities costs. The increase in per unit production costs from 1999 to 2000 was a result of production decline coupled with higher offshore oil and gas field servicing and 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;

- the surface use and restoring 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.

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.

Major Encumbrances

Substantially all of our assets, with the exception of Argo, L.L.C., and Argo I, L.L.C., together with our management agreement, and our general partner's one percent general partner interest, are pledged as collateral under our existing revolving credit facility. Substantially all of Argo's assets are pledged under Argo's limited recourse term loan. In addition, Poseidon, our equity investee, currently has a credit facility under which substantially all of its assets are pledged. For a discussion of our credit facilities, see Item 8, Financial Statements and Supplementary Data, Note 6.

Environmental

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

Employees

Employees of El Paso Corporation, through our general partner, perform all of our administrative and operational activities under a management agreement. Therefore, we had no direct employees at December 31, 2001. 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 our behalf, including, but not limited to, expenses incurred by our general partner under this management agreement.

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.

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 February 27, 2002, there were approximately 686 holders of record of common units.

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

	Common Units		Distributions Declared per Unit	
	High	Low	Common	Preference(1)
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	—
2000				
Fourth Quarter	$27.7500	$23.0000	$0.5500	$ —
Third Quarter	28.0000	22.5000	0.5375	0.2750
Second Quarter	26.0000	19.5000	0.5375	0.2750
First Quarter	21.3750	18.1250	0.5250	0.2750

(1) As of October 2000, all publicly held preference units were converted into common units or redeemed.

In January 2002, we declared a quarterly distribution of $0.625 per common unit which was paid on February 15, 2002, to unitholders of record on January 31, 2002. This increase in our quarterly distribution rate represents an annual increase of $0.05 per unit to an annual distribution rate of $2.50 per unit.

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. 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, 2001, we paid $80.9 million in distributions to our common unitholders, including El Paso Corporation, and $25.5 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 beginning in the fourth quarter of 2010, any unpaid accruals occurring after September 2010 on these preference units will be currently payable and must be completely paid, prior to any distributions on common units. See Item 8, Financial Statements and Supplementary Data, Note 8, for a discussion relating to cash distributions.

Public Offering of Common Units

In October 2001, we completed 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 which was an exempt transaction under Section 4(2) of the Securities Act of 1933, as amended, 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 million of cumulative redeemable Series B preference units in exchange for the Crystal 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, 2001, the liquidation value of the outstanding Series B preference units was approximately $143 million.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2001	2000	1999	1998	1997
	(In thousands, except per unit amounts)				
Operating Results Data(1):					
Operating revenues(2)	$202,231	$112,415	$63,659	$48,731	$75,435
Net income (loss)(3)	55,149	20,497	18,817	746	(1,138)
Basic and diluted income (loss) per unit (4)	0.38	(0.03)	(0.34)	0.02	(0.06)
Distributions per common unit	2.31	2.15	2.10	2.075	1.75
Distributions per preference unit(5)	—	0.825	1.10	1.825	1.75

	As of December 31,				
	2001	2000	1999	1998	1997
	(In thousands)				
Financial Position Data(1):					
Total assets	$1,357,270	$869,471	$583,585	$442,726	$409,842
Revolving credit facility	300,000	318,000	290,000	338,000	238,000
Limited recourse term loan(6)	95,000	45,000	—	—	—
Long-term debt(7)	425,000	175,000	175,000	—	—
Partners' capital(8)	500,726	311,071	96,489	82,896	143,966

(1) Our operating results and financial position reflect the acquisitions of:

- 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 Crystal natural gas storage businesses 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) Operating revenues for 1999, 1998, and 1997 have been restated to exclude earnings from unconsolidated affiliates. The operating revenues in 1998 were affected by lower realized prices on oil and natural gas and inclement weather conditions which decreased production volumes.

(3) Reflects impairment charges for capitalized costs written off in 1997 as a result of the abandonment of flow lines connecting to wells abandoned by third party owners.

(4) Reflects our 1999 adoption of a preferable accounting method for allocating partnership income to our general partner and our preference and common unitholders. See Item 8, Financial Statements and Supplementary Data, Note 1, for further information.

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

(6) 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.

(7) 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:

- 5.6 million common units, which included 1.5 million common units purchased by 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 with a focus on increasing our cash flow, earnings and return to our unitholders. We intend to concentrate on fee-based operations, such as gathering, transportation, processing, storage and fractionation and to de-emphasize our commodity-based activities, such as exploration and production operations. Our strategy is to combine our position as a provider of midstream energy services in the deeper water regions of the Gulf of Mexico with an aggressive effort to acquire and develop diversified onshore midstream energy infrastructure assets.

Our strategy contemplates substantial growth through the acquisition and development 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. In addition to potential third-party acquisitions, El Paso Corporation has midstream assets that may be considered for sale to us. Our strategy has been and will continue to be expanding our operating scope, our ability to generate cash flow and our investment opportunities. Consequently, 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. We will need substantial new capital to continue to finance our strategy, including additional future uses of periodic debt and equity offerings. Significant milestones in the implementation of our strategy over the past three years include:

Year	Transaction
1999	Increased our ownership interest in Viosca Knoll to 99 percent;
	Increased our ownership interests in HIOS, East Breaks and UTOS to 50 percent;
	Placed the Allegheny oil pipeline system into service;
	Exchanged our working interest in the Prince Field for a 9 percent overriding royalty interest, with a conditional option to convert to a 30 percent working interest;
2000	Acquired the natural gas pipeline system of EPIA;
	Placed the East Breaks joint venture pipeline system in service;
	Acquired the salt dome natural gas storage businesses of Crystal;
	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 Deepwater Holdings to 100 percent. HIOS and East Breaks became indirect wholly-owned assets through this transaction;
	Acquired interests in the titleholder of and other interests in the Chaco cryogenic natural gas processing plant; and
	Acquired the Anse La Butte NGL storage facility.

Our general partner, which is owned by El Paso Corporation, manages our day-to-day operations and strategic direction. Employees of El Paso Corporation perform all of our administrative and operational activities under our management agreement or, in some cases, separate operational agreements. Additionally, El Paso Corporation elects all of our general partner's directors.

We often enter into transactions with El Paso Corporation and its subsidiaries to acquire or sell assets, and have instituted specific procedures for evaluating and valuing these transactions. Before we consider entering into a transaction with El Paso Corporation or any of its subsidiaries, we determine that 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 Special 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 approve and recommend the proposed transaction.

We will only consummate any proposed transaction with El Paso Corporation if, following its evaluation of the transaction, the Special Conflicts Committee approves and recommends the proposed transaction.

Acquisitions, Divestitures and Projects

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 agreed to make payments to us totaling $29 million. These payments, which began in the first quarter of 2001, will be made in quarterly installments of $2.25 million for the next three years and $2 million in the first quarter of 2004. From this additional consideration, we recognized income of approximately $25 million in the first quarter of 2001, which has been reflected in other income in the accompanying statements of income.

EPN Texas

In February 2001, we purchased EPN Texas from a subsidiary of El Paso Corporation for approximately $133 million. These assets include more than 600 miles of NGL gathering and transportation pipelines, as well as three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGLs into ethane, propane, and butane products which are used by refineries and petrochemical plants along the Texas Gulf Coast.

Prince TLP

In July 2001, we installed the Prince TLP facility in the Prince Field. The platform was installed in 1,450 feet of water approximately 120 miles south of New Orleans, Louisiana. We also own the related pipelines to gather and process oil and natural gas production from the Prince Field. The platform will serve as a landing spot for future oil and natural gas developments in the Ewing Bank and Green Canyon areas of the Deepwater Trend of the Gulf of Mexico. The Prince TLP platform has a capacity of 50 MBbls/d of oil and 80 MMcf/d of natural gas, as well as the capacity to accommodate a 1,200-horsepower completion rig. The deck is equipped for the future addition of numerous sub-sea well tie-backs. The first production flowed through the facility in September 2001. As part of our pending agreement to acquire assets from El Paso Corporation, we agreed to sell the Prince TLP to a subsidiary of El Paso Corporation.

Deepwater Holdings

In October 2001, we acquired the remaining 50 percent equity interest that we did not already own in Deepwater Holdings, from a subsidiary of El Paso Corporation, for approximately $81 million, including $55 million of acquired indebtedness. At the acquisition date, we also repaid Deepwater Holdings' outstanding revolving credit facility balance and terminated the facility. HIOS and East Breaks became indirect wholly-owned assets through this transaction.

Chaco Plant

In October 2001, we acquired interests in the title holder of, and other interests in, the Chaco cryogenic natural gas processing plant, the third largest natural gas processing plant in the United States measured by liquids produced, for approximately $198.5 million. The total purchase price was comprised of:

- a payment of $77 million to acquire the Chaco 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.

We receive a fixed fee from El Paso Field Services for each dekatherm of natural gas that we process. El Paso Field Services personnel continue to operate the plant. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. El Paso Field Services has the right to purchase the Chaco plant at the end of the lease term in October 2002 for approximately $77 million. If El Paso Field Services does not exercise this repurchase right, it must pay us a forfeiture penalty. If El Paso Field Services does exercise this repurchase right, our rights and obligations under the 20-year agreement will remain in place for the term of the agreement and will expire upon the termination of the agreement.

Medusa Project

In October 2001, we agreed to install a new natural gas pipeline from our Viosca Knoll system to the deepwater Medusa development in the Gulf of Mexico. We also entered into an agreement to provide natural gas gathering services for Murphy Exploration and Production Company's Medusa development. Construction of this pipeline is scheduled to begin in mid-2002, and first production from the Medusa development is anticipated by the fourth quarter of 2002. The total cost of the project is estimated to be $28 million. We expect to fund the project through borrowings on our revolving credit facility.

Matterhorn Project

In October 2001, we entered into an agreement to provide natural gas gathering services for TotalFinaElf's Matterhorn, Camden Hills and Aconcagua discoveries located in the Gulf of Mexico Deepwater Trend. Natural gas production from these fields will be delivered to our existing Viosca Knoll system. First production from Camden Hills and Aconcagua is anticipated in the summer of 2002. First production from Matterhorn is anticipated in the third quarter of 2003.

NGL Storage Facility

In December 2001, we acquired Anse La Butte, a 3.2 million barrel 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 a subsidiary of El Paso Corporation, for a significant portion of the storage capacity. In January 2002, we acquired a 3.3 million barrel propane storage business and leaching operation located in Hattiesburg, Mississippi from Suburban Propane Partners, L.P. As part of the transaction, we entered into a long-term propane storage agreement with Suburban Propane Partners for a portion of the acquired propane storage capacities. We intend to convert a portion of these assets to natural gas storage and will integrate them with our adjacent Petal natural gas storage facility. The purchase price for these assets was approximately $10 million and was funded through borrowings on our revolving credit facility.

Marco Polo Project

In December 2001, we announced an agreement with Anadarko Petroleum Corporation to jointly develop Anadarko's Marco Polo discovery, using a floating production platform capable of accommodating production from multiple fields. In conjunction with this agreement, we formed a 50/50 joint venture to construct, install, and own the platform with Cal Dive International, Inc. The platform's production capacity is expected to be 100 MBbls/d of oil and 250 Mcf/d of gas. Anadarko will have firm capacity of 50 MBbls/d of oil and 150 Mcf/d of 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. Anadarko will operate the platform. We anticipate that the facilities will be completed in 2004.

The total cost of the project is estimated to be $206 million, or approximately $103 million for our share. We expect to fund the majority of our share of the costs through non-recourse project debt financing.

Midstream Businesses

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

- the 9,400 mile EPGT Texas intrastate pipeline, with a capacity of approximately 5 Bcf/d and average throughput of 3,500 MDth/d during 2001;
- 1,300 miles of gathering system in the Permian Basin with a capacity of 465 MMcf/d and average throughput of 341 MDth/d during 2001; and
- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

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

- the sale of our Prince TLP and the 9 percent overriding royalty interest in the Prince Field for approximately $190 million after our repayment of the related limited recourse debt of $95 million;
- the issuance of $6 million in common units; and
- a cash payment of $554 million.

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

Cameron Highway Project

In February 2002, we announced that we will build and operate the Cameron Highway Oil Pipeline System, a 380-mile oil pipeline in the Gulf of Mexico. Cameron Highway will deliver up to 500 MBbls/d of oil from the southern Green Canyon and western Gulf of Mexico areas to Port Arthur and Texas City, Texas. The new pipeline is expected to be in service by the third quarter of 2004. We have entered into agreements with operating subsidiaries of BP p.l.c., BHP Billiton, and Unocal under which each of them have dedicated production from the Holstein, Mad Dog, and Atlantis Deepwater Trend discoveries for transportation on Cameron Highway. We will seek a partner or partners for up to 50 percent of the $450 million total estimated cost. We expect to fund a majority of our share of the costs through non-recourse project financing. It is estimated that the majority of the capital outlay for the project will occur in 2003 and 2004.

Results of Operations

Our business activities are segregated into five segments:

- Natural Gas Gathering and Transportation;
- Liquid Transportation and Handling;
- Platforms;
- Natural Gas Storage; and
- Oil and Natural Gas Production.

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 Liquid Transportation and Handling. This segment also includes the liquid transportation services of the Allegheny and Poseidon oil pipelines which were previously reflected in the Natural Gas Gathering and Transportation segment. The operating results of the Chaco plant are also included in the Liquid Transportation and Handling segment. All historical periods have been presented on the basis of the current segment presentation. Each of our segments is a strategic business unit that offers different services or products, and we manage each of these segments separately as they require different technology and marketing strategies. Since earnings from investments in unconsolidated affiliates can be a significant source of earnings in our segments, we have chosen to evaluate segment performance based on earnings before interest expense and taxes (EBIT).

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 13.

The following table presents EBIT by segment and in total for each of the three years ended December 31:

	2001	2000	1999
		(In thousands)	
Earnings Before Interest Expense and Income Taxes			
Natural Gas Gathering and Transportation	$ 26,985	$37,004	$33,730
Liquid Transportation and Handling	43,676	21,322	20,042
Platforms	24,950	22,491	15,962
Natural Gas Storage	9,568	2,193	—
Oil and Natural Gas Production	2,376	(6,956)	(6,545)
Segment EBIT	107,555	76,054	63,189
Non-segment activity, net	(9,176)	(8,695)	(9,287)
Consolidated EBIT	$ 98,379	$67,359	$53,902

Segment Results

Natural Gas Gathering and Transportation

The Natural Gas Gathering and Transportation segment includes the Viosca Knoll system, the HIOS system, the East Breaks system, the EPIA system and the Indian Basin lateral. The natural gas gathering and transportation pipelines primarily earn revenue from fixed-fee-based services or market-based rates usually related to the monthly natural gas price index for volume gathered. These pipelines typically involve life-of-reserve commitments with both firm and interruptible components. 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 approximately four percent of EPIA's sales. There was no significant impact on our realized cost of natural gas from these swaps for the year ended December 31, 2001. 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. The Indian Basin lateral, which we placed into service in June 2001, is a ten mile pipeline that connects the Indian Basin processing and treating plant to El Paso Field Services' Carlsbad Gathering System. The Indian Basin lateral has firm arrangements where we receive a monthly fixed fee regardless of the level of throughput.

	Year Ended December 31,		
	2001	2000	1999
		(In thousands)	
Natural gas gathering and transportation revenues	$ 34,230	$ 29,597	$ 20,975
Natural gas sales	59,701	34,531	—
Total operating revenues	93,931	64,128	20,975
Cost of natural gas	(51,542)	(28,160)	—
Operating expenses	(20,519)	(9,327)	(11,281)
Other income	5,115	10,363	24,036
EBIT	$ 26,985	$ 37,004	$ 33,730
Natural gas volumes (Gross MDth/d)			
Viosca Knoll	551	612	709
HIOS	979	870	792
East Breaks	245	112	—
EPIA	171	120	—
Indian Basin	22	—	—
Gulf of Mexico assets sold	243	1,008	1,009
Total natural gas volumes	2,211	2,722	2,510

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Natural gas gathering and transportation revenues for the year ended December 31, 2001, were $4.6 million higher than in 2000, primarily due to our consolidation of Deepwater Holdings in October 2001 and revenues received from our Indian Basin lateral which went into service in June 2001. These increases were partially offset by lower volumes on our Viosca Knoll system due to Tropical Storm Barry in August 2001 and the sale of the Tarpon and Green Canyon pipeline assets in January 2001. Natural gas sales margin, or natural gas sales less cost of natural gas, for the year ended December 31, 2001, was $1.8 million higher than in 2000 due to higher volumes on EPIA as a result of a full twelve months of our ownership in 2001 as well as larger spreads between our natural gas sales prices and the cost to purchase natural gas in 2001. We acquired EPIA in March 2000.

Operating expenses for the year ended December 31, 2001, were $11.2 million higher than in 2000, primarily due to the consolidation of Deepwater Holdings in October 2001 and the abandonment and impairment of the Manta Ray pipeline in January 2001, partially offset by lower operating expenses resulting from the 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 $5.2 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. 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.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Natural gas transportation revenues for the year ended December 31, 2000, were $8.6 million higher than in 1999, primarily due to the consolidation of Viosca Knoll in June 1999. Natural gas sales margin for the year ended December 31, 2000, was $6.4 million due to the purchase of EPIA in March 2000.

Operating expenses for the year ended December 31, 2000, were $2.0 million lower than in 1999, primarily due to cost recoveries under our operating agreement with Deepwater Holdings relative to actual costs incurred.

Other income for the year ended December 31, 2000, was $13.7 million lower than in 1999, primarily due to the consolidation of Viosca Knoll in June 1999 and a gain related to the sale of a portion of our interest in Deepwater Holdings in 1999 to ANR Pipeline as part of the formation of Deepwater Holdings as a 50/50 joint venture with ANR.

Liquid Transportation and Handling

The Liquid Transportation and Handling segment includes the NGL transportation pipelines and fractionation plants of EPN Texas, the Chaco cryogenic natural gas processing plant and the Poseidon and Allegheny offshore oil pipelines. The EPN Texas plants fractionate NGLs into ethane, propane, and butane products which are used by refineries and petrochemical plants along the Texas Gulf Coast. We receive a fixed fee for each barrel of NGLs transported and fractionated by the EPN Texas facilities from a subsidiary of El Paso Corporation. We have dedicated 100 percent of our capacity to this subsidiary. As part of the acquisition of EPN Texas fractionation assets and dedication of their capacity to a subsidiary of El Paso Corporation, we secured a commitment from this subsidiary that the 2001 utilization rate of these facilities would average at least 85 percent. The average utilization rate for 2001 was 73 percent, accordingly we have recorded a receivable of $1.8 million related to the shortage of committed volumes. This commitment terminated in 2001 and future revenue will reflect the actual number of barrels of NGLs transported and fractionated. The Chaco plant receives and processes natural gas from the San Juan Basin located in New Mexico. We receive a fixed fee for each dekatherm processed from a subsidiary of El Paso Corporation under a 20-year fee-based processing agreement. We have dedicated up to 100 percent of our capacity to this subsidiary. In addition to processing fees, we also receive monthly lease revenues from this subsidiary. The lease terminates in October 2002. 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.

	Year Ended December 31,		
	2001	2000	1999
		(In thousands)	
Liquid transportation and handling revenues	$ 39,460	$ 8,307	$ 2,029
Operating expenses	(13,994)	(1,434)	(874)
Other income	18,210	14,449	18,887
EBIT	$ 43,676	$ 21,322	$ 20,042
Liquid volumes (Bbl/d)			
Poseidon Oil Pipeline(1)	155,453	157,436	169,708
Allegheny Oil Pipeline	12,985	17,569	11,696
EPN Texas	63,212	—	—
Total liquid volumes	231,650	175,005	181,404
Chaco processing volumes (MDth/d)(2)	648	—	—

(1) Represents 100 percent of Poseidon volumes.

(2) Represents average volumes since the acquisition date of October 18, 2001.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues for the year ended December 31, 2001, were $31.2 million higher and operating expenses were $12.6 million higher than in 2000, primarily due to the purchases of EPN Texas in February 2001 and the Chaco plant in October 2001. Excluding these acquisitions, 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 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 business interruption insurance proceeds in 2000 related to the Poseidon pipeline rupture.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Revenues for the year ended December 31, 2000, were $6.3 million higher and operating expenses were $0.6 million higher than in 1999, primarily due to a full year of revenues in 2000 from the Allegheny system, which went into service in the fourth quarter of 1999.

Other income for the year ended December 31, 2000, was $4.4 million lower than in 1999, primarily due to lower earnings from Poseidon as a result of a pipeline rupture in January 2000. Partially offsetting this decrease was the receipt of business interruption insurance proceeds in 2000 related to the Poseidon pipeline rupture.

Platforms

The Platform segment consists of the Prince TLP, 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 pending agreement to acquire assets from El Paso Corporation in the first quarter of 2002, we agreed to sell the Prince TLP to a subsidiary of El Paso Corporation.

	Year Ended December 31,		
	2001	2000	1999
		(In thousands)	
Platform services revenue	$ 36,158	$26,833	$23,883
Operating expenses	(10,576)	(4,342)	(7,921)
Other loss	(632)	—	—
EBIT	$ 24,950	$22,491	$15,962
Natural gas platform volumes (MDth/d)			
Prince TLP	1	—	—
East Cameron 373	170	115	94
Viosca Knoll 817	12	3	3
Garden Banks 72	7	15	—
Total natural gas platform volumes	190	133	97
Oil platform volumes (Bbl/d)			
Prince TLP	1,006	—	—
East Cameron 373	1,927	101	138
Viosca Knoll 817	2,049	1,982	1,816
Garden Banks 72	1,487	3,408	—
Total oil platform volumes	6,469	5,491	1,954

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Platform services revenue for the year ended December 31, 2001, were $9.3 million higher than in 2000, primarily due to demand charges received from our Prince TLP facility which went into service in September 2001 and 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 $6.2 million higher than in 2000, primarily due to higher expenses related to the Prince TLP facility in 2001 and 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 our Gulf of Mexico platform assets, partially offset by $3.4 million associated with the additional consideration from El Paso Corporation related to the sale of these assets.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Platform services revenue for the year ended December 31, 2000, were $3.0 million higher than in 1999, primarily due to additional demand charges on East Cameron 373.

Operating expenses for the year ended December 31, 2000, were $3.6 million lower than in 1999, primarily due to the favorable resolution of litigation in June 2000.

Natural Gas Storage

The Natural Gas Storage segment includes the Petal and Hattiesburg storage facilities which were acquired in August 2000. These facilities serve the Northeast, Mid-Atlantic and Southeast natural gas markets. For the years ended December 31, 2001 and 2000, the revenues from Petal and Hattiesburg 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 fees. Operating expenses consist of management and operating fees and depreciation on the storage facilities.

	Year Ended December 31,		
	2001	2000	1999
		(In thousands)	
Natural gas storage revenue	$19,373	$ 6,182	$ —
Operating expenses	(9,825)	(3,992)	—
Other income	20	3	—
EBIT	$ 9,568	$ 2,193	$ —

Year Ended December 31, 2001 Compared to Year Ended December 31, 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 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.

Oil and Natural Gas Production

The Oil and Natural Gas Production segment primarily includes the Garden Banks 72, Garden Banks 117 and Viosca Knoll 817 Blocks. 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 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.

	Year Ended December 31,		
	2001	2000	1999
		(In thousands)	
Natural gas revenues	$ 18,248	$ 12,819	$ 24,829
Oil, condensate, and liquids revenues	8,062	7,733	5,136
Total operating revenues	26,310	20,552	29,965
Operating expenses	(23,934)	(27,508)	(36,510)
EBIT	$ 2,376	$ (6,956)	$ (6,545)
Volumes			
Natural gas sales (MMcf)	4,038	7,185	12,211
Oil, condensate, and liquid sales (MBbls)	343	295	357
Weighted average realized prices(1)			
Natural gas ($/Mcf)	$ 4.52	$ 1.86	$ 2.02
Oil, condensate, and liquids ($/Bbl)	$ 23.47	$ 25.26	$ 14.32

(1) Average realized prices for 2000 and 1999 were impacted by hedging activities. There were no hedges in place relating to our oil and natural gas production in 2001.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Oil and natural gas operating revenues for the year ended December 31, 2001, were $5.8 million higher than in 2000. The increase was a result of higher realized natural gas prices and higher oil production volumes. Partially offsetting the increase in revenues was a decrease in natural gas production volumes due to declines of existing natural gas reserves.

Operating expenses for the year ended December 31, 2001, were $3.6 million lower than in 2000, primarily due to lower depletion from natural gas production as a result of upward revisions of prior estimates of reserve quantities.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Oil and natural gas operating revenues for the year ended December 31, 2000, were $9.4 million lower than in 1999. The decrease was a result of lower oil and natural gas production due to normal production declines of existing reserves, the permanent shut-in of two wells at Viosca Knoll Block 817, the temporary shut-in of Garden Banks Blocks 72 and 117 as a result of the Poseidon pipeline rupture, and lower realized prices for natural gas, partially offset by higher realized prices for oil. Realized prices for oil and natural gas were affected by hedges in place during 1999 and 2000.

Operating expenses for the year ended December 31, 2000, were $9.0 million lower than in 1999 due to lower depletion from lower oil and natural gas production as a result of upward revisions of prior estimates of reserve quantities.

Non-segment Activity

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Earnings before interest expense and income taxes related to non-segment activity for the year ended December 31, 2001, was $0.5 million lower than in 2000 primarily due to higher general and administrative expenses due to transactional fees related to our acquisitions and dispositions of several assets in 2001, partially offset by interest income received on the quarterly payments from El Paso Corporation.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Earnings before interest expense and income taxes related to non-segment activity for the year ended December 31, 2000, was $0.6 million higher than in 1999 primarily due to higher general and administrative expenses in 1999.

Interest and Debt Expense

Year Ended December 31, 2001 Compared With Year Ended December 31, 2000

Interest and debt expense, net of capitalized interest, for the year ended December 31, 2001, was approximately $3.9 million lower than 2000. This decrease primarily relates to an increase in capitalized interest of approximately $7.7 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 an increase of approximately $3.8 million due to additional borrowings under our limited recourse term loan and the issuance of our $250 million 8 1/2% Senior Subordinated Notes in May 2001.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Interest and debt expense, net of capitalized interest, for the year ended December 31, 2000, was approximately $11.7 million higher than 1999. This increase primarily relates to an increase in interest expense of approximately $13.9 million due to higher average interest rates and higher average debt outstanding related to construction activities and the acquisition of EPIA. This increase was slightly offset by higher capitalized interest of approximately $2.2 million in 2000.

Liquidity and Capital Resources

Cash From Operating Activities

Net cash provided by operating activities was approximately $87 million for the year ended December 31, 2001, compared to approximately $48 million for the same period in 2000. The increase was primarily attributable to operating cash flows from our acquisitions of the Crystal natural gas storage businesses in August 2000, EPN Texas in February 2001 and Chaco and Deepwater Holdings in October 2001, as well as higher cash distributions from unconsolidated affiliates, partially offset by lower operating cash flows as a result of the sale of several of our Gulf of Mexico assets in 2001.

Cash From Investing Activities

Net cash used in investing activities was approximately $500 million for the year ended December 31, 2001. Our investing activities during 2001 included our purchase of EPN Texas in February 2001, our general partner’s one percent non-managing ownership interest in our operating subsidiaries in May 2001, the Chaco Plant and the remaining 50 percent interest in Deepwater Holdings we did not already own in October 2001. Additional capital investments also included the expansion of the Petal natural gas storage facility, construction of the Prince TLP and routine investments in our existing assets, partially offset by net proceeds of $109 million received from the sale of several of our Gulf of Mexico assets.

Cash From Financing Activities

Net cash flows provided by financing activities totaled approximately $405 million for the year ended December 31, 2001. During 2001, we received net proceeds of $610 million from borrowings under our revolving credit facility and from our limited recourse term loan. We obtained net proceeds of $243 million in May 2001 through the issuance of our $250 million 8 1/2% Senior Subordinated Notes. Our financing activities in 2001 also include cumulative issuances of 8.2 million common units generating net proceeds of

$287 million. Partially offsetting these activities were distributions to our partners of $106 million, the redemption of $50 million liquidation value of Series B preference units and payments on our revolving credit facility of $581 million.

We expect that future funding for capital expenditures, acquisitions, and other investing activities and for long-term debt retirements, distributions, and other financing activities will be provided by internally generated funds, available capacity under existing credit facilities, and the issuance of debt or partners' equity. In February 2002, our universal shelf registration to offer up to $1 billion of capital securities representing limited partnership interests and debt securities and related guarantees, as filed with the Securities and Exchange Commission (SEC), became effective.

Liquidity

We rely on cash generated from internal operations, including cash distributions from our equity investee, as our primary source of liquidity, supplemented by our available credit facility, and the issuance of long-term debt and common units. Our cash from internal operations may change in the future due to a number of factors, some of which we cannot control, including the price we will receive for the services we provide, and products we sell and the demand for our services and products, operational risks, and other factors. The availability of borrowings under our credit agreement is subject to specified conditions, which management believes we currently meet. These conditions include compliance with the financial covenants and ratios required by the agreement, absence of default under the agreement, and continued accuracy of the representations and warranties contained in the agreement, including the absence of any material adverse changes since the specified dates. Funding from the capital markets for long-term debt or equity may not be available for a number of reasons, including a lack of liquidity for our industry segment, a change in our credit rating or changes in market conditions. For a discussion of our financing arrangements, see Item 8, Financial Statements and Supplementary Data, Note 6.

Our strategy contemplates substantial growth through constructing and acquiring additional assets and businesses. Limitations on our access to capital would impair our ability to execute this strategy, and expensive capital would limit our ability to acquire or construct assets. Accordingly, access to necessary capital resources on satisfactory terms, including through periodic debt and equity offerings, is a key component of our strategy.

The following table presents the timing and amounts of our contractual cash obligations as of December 31, 2001 that we believe could affect our liquidity (in millions):

Contractual Cash Obligations	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	Total
Revolving credit facility	$ —	$300	$ —	$ —	$300
Limited recourse term loan	19	38	38	—	95
10 3/8% Senior Subordinated Notes	—	—	—	175	175
8 1/2% Senior Subordinated Notes	—	—	—	250	250
Total Contractual Cash Obligations	$ 19	$338	$ 38	$425	$820

Our limited recourse term loan is collateralized by substantially all of Argo's assets. The term loan agreement restricts Argo's ability to pay distributions to us. If Argo defaults on its payment obligations, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Argo up to $30 million. As of December 31, 2001, Argo had not paid us, or any of our subsidiaries, any distributions. As part of our pending agreement to acquire assets from El Paso Corporation in the first quarter of 2002, we agreed to sell the Prince TLP to a subsidiary of El Paso Corporation. In conjunction with the sale of the Prince TLP, we will repay the outstanding balance on the limited recourse term loan.

We have two features contained in our debt instruments described as ratings triggers. The features provide us, rather than creditors, with certain rights in the event that our credit ratings change to an investment grade level. These triggers involve our:

- $250 million 8 1/2% Senior Subordinated Notes due 2011 where many covenants will be suspended in the event we achieve an investment grade credit rating; and

- $600 million revolving credit facility where we will receive a 38 to 50 basis point reduction in our interest rate in the event we achieve an investment grade credit rating.

There are no other trigger features related to the $250 million Senior Subordinated Notes or our revolving credit facility. In addition, there are no trigger features or mechanisms contained in any of our other debt instruments or commercial arrangements.

Poseidon has a $185 million revolving credit facility which matures in 2004. Poseidon currently has $150 million outstanding under this revolving credit facility.

For the Marco Polo and Cameron Highway projects, we intend to partner with others and seek non-recourse project financing. Cash requirements for our equity portion of these projects and the acquisition of the midstream assets from El Paso Corporation will be funded through a combination of cash from internal operations and long-term debt and common unit offerings. In addition, we would expect to use our revolving credit facility to initially fund these projects or to cover expenditures for a short period of time.

We have firm commitments related to the Cameron Highway project and are obligated for the entire cost of the project until we obtain a partner. We have non-binding letters for our Marco Polo and Medusa projects and therefore our obligations for these projects are still subject to change.

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 no reserves for legal and environmental matters. For us, 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.

Collectibility of Accounts Receivable

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. The allowance could increase or decrease based on a change in our view of the cash flow strength of our customers. This view is generally customer specific and includes known cash flow problems such as bankruptcies, possible bankruptcies, changes in credit ratings and other factors. Our view of account collectibility is also affected by the current weakness or strength of the customers' business sector, the overall energy sector and overall general economic conditions.

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, prices, 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.

Volume Measurement

We record amounts for natural gas gathering and transportation revenue, liquid transportation and handling revenue, natural gas sales and related natural gas purchases, and the sale of production based on volumetric calculations. Variances resulting from such calculations are inherent in our business. We do not believe that differences attributable to unresolved variances are material.

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 gas properties. Changes in reserve quantities as described above will cause corresponding changes in depletion expense in periods subsequent to the quantity revision.

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 2002 and 2003. Some of these new rules will 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 FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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.

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 and making distributions to unitholders.

We have a significant amount of indebtedness and the ability to incur substantially more indebtedness. In May 2001, we issued $250 million of 8 1/2% Senior Subordinated Notes due in 2011 and in May 1999, we issued $175 million of 10 3/8% Senior Subordinated Notes due in 2009. All of our senior subordinated notes are supported by guarantees of our subsidiaries. We are also party to a $600 million revolving credit facility, which is collateralized by a pledge of the equity of our subsidiaries and substantially all of our other assets and supported by guarantees of our subsidiaries. As of December 31, 2001, we had $300 million outstanding under this revolving credit facility. In addition, Argo, L.L.C., an indirect wholly-owned subsidiary, has a $95 million limited recourse term loan from a group of commercial lenders, which was entered into in August 2000. As of December 31, 2001, Argo had $95 million outstanding under that loan, and the average interest rate was 4.10%. If Argo defaults on its payment obligations, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Argo up to $30 million. 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.

From time to time, our joint ventures also incur indebtedness. As of December 31, 2001, one of our joint ventures, Poseidon Oil Pipeline Company, L.L.C., had a revolving credit facility to provide up to $185 million with $150 million outstanding which is collateralized by a substantial portion of Poseidon's assets. The average floating interest rate was 3.9% at December 31, 2001.

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 revolving credit facility. Argo, L.L.C. and Argo I, L.L.C., our only unrestricted subsidiaries, must also comply with various affirmative and negative covenants related to Argo, L.L.C.'s limited recourse term loan. Among other things, these covenants limit the ability of us and those 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.

That indebtedness also requires us and those subsidiaries to make mandatory repayments under certain circumstances, including when we sell certain assets, fail to achieve or maintain certain financial targets or experience a change in control. We do not have the right to prepay the balance outstanding under our senior subordinated notes without incurring substantial economic penalties.

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, it 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 agreement, 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 agreement or under arrangements which may have terms and conditions at least as restrictive as those contained in our existing credit agreement 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, and 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. Such an 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 acquisition and development of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. We intend to continue de-emphasizing our commodity-based activities, such as exploration and production operations, and to concentrate on fee-based operations, such as gathering, transportation, processing, storage and fractionation. 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 acquisitions, joint ventures and stand-alone projects 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. These acquisitions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets. If we consummate any future acquisitions, our capitalization and results of operations may change significantly and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds.

We will need new capital to finance the future acquisition and construction 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 acquire or construct 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.

In addition, we are experiencing increased competition for the assets we purchase. 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 acquisition, construction and development 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 purchase, 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 cannot assure you that we will be able to complete our projects 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; 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.

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 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 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. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place administrative and operational burdens on us. Further, more fundamental changes could be required such as a complete organizational separation or sale of HIOS and Petal.

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, we cannot assure you that the current regulatory regime will remain unchanged or of the effect any changes in that regime would have on our financial position, results of operations or cash flows.

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. We cannot assure you that we will not incur material environmental costs and liabilities.

A natural disaster, catastrophe or other interruption event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise adversely affect our cash flow.

The nature of some of our operations involves higher risks of severe personal injury, property damage and environmental damage, 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 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 adversely impact the market price of our debt and equity securities and the amount of cash available for payment of the debt securities and distribution to our limited partners. In order to reduce the effects of any such incident, we maintain insurance coverage that includes some property and business interruption insurance. We believe that this insurance coverage is adequate, although it does not cover many types of interruptions that might occur. We cannot assure you that the proceeds of any such insurance would be paid in a timely manner or be in an amount sufficient to meet our needs if such an event were to occur or that we can renew it or other desirable insurance on commercially reasonable terms, if at all.

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 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 especially, 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, capital budget limitations or the lack of available capital. We cannot assure you that additional reserves, if discovered, would 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.

Our storage businesses depend on neighboring pipelines to transport natural gas.

To obtain natural gas, our storage businesses depend on the pipelines to which they have access. Any interruption of service on those pipelines or adverse change in their terms and conditions of service could have a material adverse effect on our ability (and the ability of our customers) to transport natural gas to and from our facilities and a corresponding material adverse effect on our storage revenues. In addition, the rates charged by those interconnected pipelines for transportation to and from our facilities affect the utilization and value of our storage services. Significant changes in the rates charged by those pipelines or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our storage revenues.

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 cannot assure you that any of these reserves will be gathered, transported, processed, fractionated, stored or otherwise handled by us. 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.

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 reducing 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.

Pipelines and Platforms — Price decreases could have an adverse effect on the discovery and development of replacement reserves.

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.

Natural Gas Storage — Natural gas price stability could have an adverse effect on revenues 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, we cannot assure you that the market for natural gas will 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.

Processing and Fractionation — The processing and fractionation businesses are cyclical and are dependent in part upon the spreads between prices for natural gas, NGLs and petroleum products.

Prices for natural gas, NGLs and NGL components can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Since our processing and fractionation facilities provide fee-based services, for which we receive a fixed fee for each unit of natural gas we process or NGL we fractionate, our processing and fractionation operations are not directly affected by fluctuations in prices for natural gas, NGLs and NGL components. However, if the spread between prices for natural gas, NGLs 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 NGLs, or to process less natural gas or fractionate less NGLs. 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 NGLs and separating the NGL components from the NGLs 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 NGLs is greatest when the demand for NGLs 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 processing and 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 processing and fractionation industries 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 2001, 2000 and 1999 was 89 percent, 91 percent and 93 percent. The monthly utilization rate for our fractionation facilities during the 12 months ending December 31, 2001 was as low as 41 percent and as high as 88 percent. However, our average annual utilization rate for our fractionation facilities for 2001, 2000 and 1999 were 73 percent, 89 percent and 88 percent. We secured a commitment from a subsidiary of El Paso Corporation that the utilization rate of our fractionation facilities during 2001 would be at least 85 percent at a rate of $1.01 per barrel. This commitment expired on December 31, 2001, and we have recorded a receivable of $1.8 million related to the shortage of committed volumes.

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.

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 revolving credit facility and the credit facilities of our joint ventures, are variable. We partially hedge our interest rate exposure, from time to time, using financial derivative instruments. Our results of operations, and our cash flow, could be materially affected by significant increases or decreases in interest rates.

Our use of derivative financial instruments could result in financial losses.

We try to limit a portion of the adverse effects resulting from changes in oil and natural gas commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time, 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 change. In addition, even though our management monitors our hedging activities, we could experience losses resulting from them. 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.

Our fractionation facilities are dedicated, and our Chaco processing plant is primarily dedicated, to a single customer, the loss of which could adversely affect us.

In connection with our acquisition of our 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 NGLs 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 NGLs 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 NGLs.

In addition, in connection with our acquisition of interests in the titleholder of, and other interests, in the Chaco cryogenic natural gas processing plant, we entered into a 20-year fee-based processing agreement with El Paso Field Services, a subsidiary of El Paso Corporation. In that agreement, El Paso Field Services agreed to deliver all of the natural gas received into the gathering system and certain related facilities owned by El Paso Field Services and its subsidiaries located in the San Juan Basin area of New Mexico to our Chaco natural gas processing plant. We have agreed to use 100 percent of the capacity of our Chaco plant to process the natural gas delivered by El Paso Field Services, subject to our ability to use our available capacity to process natural gas delivered by third parties at any time that El Paso Field Services does not utilize 100 percent of our capacity. We receive a fixed fee from El Paso Field Services for each dekatherm of natural gas that the plant processes, and will bear all costs associated with the plant's ownership and operations.

Our operations are likely to be materially adversely affected if either of these arrangements are terminated or if El Paso Field Services does not deliver enough NGLs or natural gas to us to ensure that we can maintain a profitable utilization rate or does not fully perform its obligations under the agreement.

Risks Inherent in an Investment in Our Securities

Unitholders will have limited voting rights and will not control our general partner.

Unlike the holders 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. In addition, absent voluntary withdrawal, our unitholders will not have the right to elect the general partner on an annual or any other continuing basis. Furthermore, the general partner may not be removed as our general partner except upon the affirmative vote of the holders of at least 55 percent of our outstanding limited partner interests, including units owned by the general partner and its affiliates.

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. If we issue more limited partner interests, it will reduce each unitholder's proportionate ownership interest in us. This could cause the market price of the unitholders' securities 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 issued any such securities, it could adversely affect each unitholder's voting power.

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 Texas, Alabama, Louisiana, Mississippi and New Mexico and plan to expand into more states. In some states, 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.

In addition, under Delaware law, an assignee who becomes a substitute limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except the assignee is not obligated for liabilities that were unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

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 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.

Federal and state statutes would allow courts, under specific circumstances, to subordinate further or void our debt securities and the related guarantees and require holders of our debt securities to return payments received from us.

Under the federal bankruptcy law and comparable provisions of state fraudulent transfer laws, a court could further subordinate or void our debt securities and the related guarantees if, at the time the debt securities and the guarantees were issued, certain facts, circumstances and conditions existed, including that:

- we received less than reasonably equivalent value or fair consideration for the incurrence of such indebtedness;

- we were insolvent or rendered insolvent by reason of such incurrence;

- we were engaged in a business or transaction for which our remaining assets constituted unreasonably small capital; or

- we intended to incur, or believed that we would incur, indebtedness we could not repay at its maturity.

In such a circumstance, a court could require the holders of our debt securities to return to us or pay to our other creditors amounts we paid under our debt securities. This would entitle other creditors to be paid in full before any payment could be made under our debt securities. We may not have sufficient assets to fully pay our debt securities after the payment to other creditors. The guarantees of our debt securities by our subsidiaries could be challenged on the same grounds as our debt securities. In addition, a creditor may avoid a guarantee based on the level of benefits received by a guarantor compared to the amount of the subsidiary guarantee. The indentures relating to our debt securities contain a savings clause, which generally limits the obligations of each guarantor to the maximum amount that is not a fraudulent conveyance. If a subsidiary guarantee is avoided, or limited as a fraudulent conveyance or held unenforceable for any other reason, you would not have any claim against the guarantors and would be only creditors of us and El Paso Energy Partners Finance Corporation and any guarantor whose subsidiary guarantee was not avoided or held unenforceable. In such event, claims of holders of debt securities against a guarantor would be subject to the prior payment of all liabilities (including trade payables) of such guarantor. We cannot assure you that, after providing for all prior claims, there would be sufficient assets to satisfy claims of holders of debt securities relating to any avoided portions of any of the subsidiary guarantees.

The measures of insolvency for purposes of these fraudulent transfer laws will vary depending upon the law applied in any proceeding to determine whether a fraudulent transfer has occurred. Generally, however, we would be considered insolvent if:

- the sum of our indebtedness, including contingent liabilities, were greater than the fair value or fair saleable value of all of our assets;

- if the present fair value or fair saleable value of our assets were less than the amount that would be required to pay our probable liability on our existing indebtedness, including contingent liabilities, as it becomes absolute and mature; or

- we could not pay our indebtedness as it becomes due.

There is a risk of a preferential transfer if:

- a subsidiary guarantor declares bankruptcy or its creditors force it to declare bankruptcy within 90 days (or in certain cases, one year) after a payment on the guarantee; or

- a subsidiary guarantee was made in contemplation of insolvency.

The subsidiary guarantee could be avoided by a court as a preferential transfer. In addition, a court could require holders of debt securities to return any payments made on our debt securities during the 90-day (or one-year) period.

We may not be able 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 all of our general partner interests, or the sale of all or substantially all of our assets), we will be required to repay the amounts outstanding under our revolving credit facility and to offer to repurchase our debt securities at 101 percent of the principal amount, plus accrued and unpaid interest to the date of repurchase. We cannot assure you that we will have sufficient funds available or that we will be permitted by our other debt instruments to fulfill these obligations upon the occurrence of a change of control.

There may be no prior market for some of our debt or equity securities, and we cannot assure you that an active, liquid trading market will develop for these securities.

Some of our debt and equity securities have no established trading market and may not be listed on any securities exchange. The liquidity of the trading market in such securities, and the market price quoted for such securities, may be adversely affected by changes in the overall market for those securities, especially high yield securities, and by changes in our financial performance or prospects or in the prospects for companies in our industry generally. As a result, you cannot be sure that an active trading market will develop for those securities.

The rights of holders of some of our debt securities to receive payments are unsecured and contractually subordinated to most of our existing indebtedness and, possibly, any additional indebtedness we incur. Further, the guarantees of our debt securities are junior to all the guarantors' existing indebtedness and possibly to all their future borrowings.

Some of our debt securities and the related subsidiary guarantees rank behind most of our and the subsidiary guarantors' existing senior indebtedness (other than trade payables and certain other indebtedness) and possibly all additional senior indebtedness (other than trade payables) we incur unless, and to the extent, that additional indebtedness expressly provides that it ranks equal with, or junior in right of payment to, our debt securities and the related guarantees. Further, our debt securities may rank senior to, equal with or subordinate to our existing senior subordinated notes and the guarantees of those notes.

In addition, all payments on our debt securities and the related guarantees may be blocked in the event of a payment default or in the event of certain non-payment defaults on our significant senior indebtedness.

In the event of a bankruptcy, liquidation, reorganization or similar proceeding relating to us, any subsidiary guarantors or our property, our assets or the assets of the subsidiary guarantors would be available to pay obligors under the subordinated debt securities only after all payments had been made on our or the guarantors' senior indebtedness. Our creditors and the subsidiary guarantors' creditors holding claims which are not subordinated to any applicable senior indebtedness will in all likelihood be entitled to payments before all of our or the subsidiary guarantors' senior indebtedness has been paid in full. Therefore, holders of the subordinated debt securities will participate with trade creditors and all other holders of our and the guarantors' unsubordinated indebtedness in the assets remaining after we and the guarantors have paid all of the senior indebtedness. However, because the subordinated debt securities indenture may require that amounts otherwise payable to holders of the subordinated debt securities in a bankruptcy, liquidation, reorganization or similar proceeding be paid to holders of senior indebtedness instead, holders of the subordinated debt securities may receive less, ratably, than holders of trade payables and other creditors in any such proceeding. In any of these cases, we and the subsidiary guarantors may not have sufficient funds to pay all of our creditors and, therefore, holders of subordinated debt securities would receive less, ratably, than the holders of senior indebtedness.

Some of our debt securities will be effectively subordinated to indebtedness and liabilities of our subsidiaries that are not guarantors.

Our debt securities will be effectively subordinated to claims of all creditors of any of our subsidiaries that are not guarantors of our debt securities. If a non-guarantor subsidiary defaults on its debt, the holders of our debt securities would not receive any money from that subsidiary until its debts are repaid in full. For example, Argo, L.L.C., an indirect wholly-owned subsidiary, is not a guarantor of our debt securities. Argo has a $95 million limited recourse loan with $95 million outstanding as of December 31, 2001. If Argo defaults on its payment obligations under its loan, the holders of our debt securities would not receive any money from Argo until the loan is repaid in full. All of our existing subsidiaries, excluding Argo and Argo I, guarantee our debt securities.

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 often enter into transactions with each other, including some relating to operating and managing assets, acquiring and selling assets, and performing services;
- we often 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 substantial 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 involving us in which El Paso Corporation and its subsidiaries had a conflict of interest include:

- in February 2002, we agreed to acquire midstream businesses from El Paso Corporation for approximately $750 million of total consideration;
- in October 2001, we acquired interests in the titleholder of, and other interests in, the Chaco cryogenic natural gas processing plant in New Mexico from a subsidiary of El Paso Corporation, among others;
- in October 2001, we purchased the remaining 50 percent equity interest that we did not already own in Deepwater Holdings, L.L.C. from a subsidiary of El Paso Corporation;

- in October 2001, we issued 5,627,070 common units, including 1,477,070 common units purchased by our general partner, and used a portion of the proceeds to redeem $50 million of our Series B preference units owned by our general partner;

- in May 2001, we purchased our general partner's 1.01 percent non-managing interest owned in twelve of our subsidiaries;

- in February 2001, we purchased fee-based NGL transportation and fractionation assets located in south Texas from subsidiaries of El Paso Corporation;

- in January and April 2001, we and Deepwater Holdings sold our interests in several offshore Gulf of Mexico assets as a result of an FTC order related to El Paso Corporation's merger with The Coastal Corporation; and

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

In addition, we and El Paso Corporation and its subsidiaries share and, therefore will compete for, the time and effort of general partner personnel who provide services to us, including directors, officers and other personnel. Officers 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 officers and directors 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 or you, on the other. Additionally, some of these shared officers and directors own and are 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 yours.

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 subsidiaries, on the other hand, and there is a benefit to our general partner or its subsidiaries in which neither we nor you 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 subsidiaries 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.

Our general partner, which is owned by El Paso Corporation, manages our day-to-day operations and strategic direction. El Paso Corporation elects all of our general partner's directors, who in turn select all of our executive officers and those of the general partner. 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 certain minimum legal requirements, El Paso Corporation makes the final determination regarding how any particular conflict of interest is resolved.

We cannot assure you that El Paso Corporation and its subsidiaries will always act in your best interest, even though doing so may appear to:

- protect and enhance El Paso Corporation's substantial investment in us;

- generate substantial cash flows to El Paso Corporation; and

- provide El Paso Corporation with efficiently priced capital for its planned acquisitions.

We are a primary vehicle for growth and development of midstream energy assets for El Paso Corporation, and we expect to receive additional transfers in the future. These future transfers from El Paso Corporation and other third-party acquisitions will be selected from time to time, based on our unique cost-of-capital advantage, our ability to integrate these growth assets into El Paso Corporation's significant

North American midstream business and our investment profile, which requires accretive transactions based on stable cash flows with growth potential. 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 it 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 (or any of our other competitors acquired by El Paso Corporation). In fact, El Paso Corporation may have financial motives to favor our competitors. 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.

Cash reserves, expenditures and other matters within the discretion of our general partner may affect distributions to unitholders.

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.

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 (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.

Our partnership agreement purports to limit our general partner's fiduciary duties and certain other obligations relating to us.

Although our general partner owes certain 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. Neither El Paso Corporation nor any of its other subsidiaries, other than our general partner, owes fiduciary duties to us.

Our general partner and its subsidiaries may sell units or other limited partner interests in the trading market, which could reduce the market price of unitholders' limited partner interests.

As of the date of this annual report, our general partner and its subsidiaries own 10,430,834 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 unitholders' limited partner interests. 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 units held by such persons. These registration rights allow our general partner and its subsidiaries to request registration of those common units and to include any of those common units in a registration of other capital securities by us.

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. We cannot assure you that any of our joint ventures or any of our unrestricted subsidiaries will continue to make distributions to us at current levels or at all.

Moreover, pursuant to some of the joint venture and subsidiary credit arrangements, we have agreed to return a limited amount of the distributions made to us by the applicable company 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 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. Depending on the particular joint venture, these more significant activities might involve 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.

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 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 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. 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. We cannot assure you that we would be able to refinance our indebtedness or that any such acquiror would 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 will not 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 or any other matter affecting us or our subsidiaries. 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 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 substitute 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. We cannot guarantee that a unitholder will 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 cannot be sure that we will not be audited by the IRS or that tax adjustments will not 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 five 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.

Non-trading Commodity Price Risk

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

During 2001, in connection with our EPIA operations, we entered into fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. These sales contracts expose us to price risk that results from the fluctuations in the market price of natural gas we are required to purchase to fulfill these contracts. We manage this price risk by simultaneously entering into commodity price swap contracts for comparable volumes of natural gas at fixed prices that settle over the same time periods as the underlying sales contracts. These commodity price swap transactions are commonly referred to as “hedges,” because, if effective, they minimize any gain or loss to our margin on the underlying sales contract at the time of settlement. We settle the commodity price swap transactions by paying the negative difference or receiving the positive difference between the price specified in the contract and the applicable settlement price indicated in the SONAT-Louisiana index (Southern National Pipeline index as published by the periodical “Inside FERC”) for the specified commodity on the established settlement date. The credit risk associated with our commodity price swap contracts is derived from the counterparty to the transaction, an affiliate of our general partner. We do not require collateral and do not anticipate non-performance by this counterparty. All of our contracts at December 31, 2001, were short term in nature.

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. The following table presents information about our non-trading commodity price swaps at December 31, 2001:

Commodity Purchase Contracts	
Contract volumes (in MDth)	765
Weighted average purchase price (per Dth)	$4.197
Contract fair value liability amount (in thousands)	$1,272

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(1) Fair value is determined from prices indicated in the SONAT-Louisiana index.

During the year ended December 31, 2000, we hedged a portion of our oil and natural gas production to reduce our exposure to fluctuations in market prices of oil and natural gas, and to meet requirements under our revolving credit facility. We used commodity price swap transactions whereby the monthly settlements were based on differences between the prices specified in the commodity price swap agreements and the settlement prices of our futures contracts quoted on the New York Mercantile Exchange, or other indices. Each of the hedging transactions on our oil and natural gas production expired in December 2000 and we have not entered any new hedging activities on our oil and natural gas production.

Interest Rate Risk

We utilize both fixed and variable rate long-term debt, and are exposed to market risk due to the floating interest rates on our revolving credit facility and limited recourse term loan. Under our revolving credit facility, the remaining principal and the final interest payment are due in May 2004. As of December 31, 2001, our revolving credit facility had a principal balance of $300 million at an average variable interest rate of 3.9% at

December 31, 2001. A change of one percent in the interest rates would cause a change in interest expense on these outstanding borrowings of approximately $3 million on an annualized basis. We are exposed to similar risks under our Poseidon joint venture credit facility and our limited recourse term loan agreement. Since we have $425 million outstanding under our indentures at fixed interest rates of 8 1/2% and 10 3/8%, 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.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the interest rate at 3.49% through January 2004 on $75 million of the $150 million outstanding on their variable rate revolving credit facility.

The table below shows cash flows and the related weighted average interest rates of our interest bearing debt by expected maturity dates at December 31, 2001. The carrying amounts of our revolving credit facility and limited recourse term loan at December 31, 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, 2001									December 31, 2000	
	Average Interest Rate	Expected Fiscal Year of Maturity of Carrying Amounts: 2002	2003	2004	2005	2006	Thereafter	Total	Fair Value	Carrying Amount	Fair Value
	(In millions, except interest rates)										
Variable Rate Debt:											
Revolving credit facility	3.9%	$ —	$ —	$300.0	$ —	$ —	$ —	$300.0	$ 300.0	$318.0	$318.0
Limited recourse term loan	4.1%	19.0	19.0	19.0	19.0	19.0	—	95.0	95.0	45.0	45.0
Fixed Rate Debt:											
10 3/8% Senior Subordinated Notes	10.4%	$ —	$ —	$ —	$ —	$ —	$175.0	$175.0	$185.5 (a)	$175.0	184.6
8 1/2% Senior Subordinated Notes	8.5%	—	—	—	—	—	250.0	250.0	252.5 (a)	N/A	N/A

(a) At December 31, 2001, the senior subordinated notes traded at a premium relative to their face value because of the favorable ratings assigned to us and because the stated interest rates on the notes exceeded the rates being paid on similar financial instruments.

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,		
	2001	2000	1999
Operating revenues			
Gathering and transportation services	$ 93,550	$ 63,499	$ 20,282
Liquid transportation and handling	39,460	8,307	2,029
Platform services	23,538	13,875	11,383
Natural gas storage services	19,373	6,182	—
Oil and natural gas sales	26,310	20,552	29,965
	202,231	112,415	63,659
Operating expenses			
Cost of natural gas	51,542	28,160	—
Operation and maintenance, net	35,548	14,461	22,402
Depreciation, depletion and amortization	38,649	27,743	30,630
Asset impairment charge	3,921	—	—
	129,660	70,364	53,032
Operating income	72,571	42,051	10,627
Other income (loss)			
Earnings from unconsolidated affiliates	8,449	22,931	32,814
Net (loss) gain on sale of assets	(11,367)	—	10,103
Other income	28,726	2,377	358
	25,808	25,308	43,275
Income before interest, income taxes and other charges	98,379	67,359	53,902
Interest and debt expense	43,130	47,072	35,323
Minority interest	100	95	197
Income tax benefit	—	(305)	(435)
	43,230	46,862	35,085
Net income	55,149	20,497	18,817
Net income allocated to general partner	24,661	15,578	12,129
Net income allocated to Series B unitholders	17,228	5,668	—
Net income (loss) allocated to limited partners before accounting change	13,260	(749)	6,688
Cumulative effect of accounting change	—	—	(15,427)
Net income (loss) allocated to limited partners	$ 13,260	$ (749)	$ (8,739)
Basic and diluted net income (loss) per unit before accounting change	$ 0.38	$ (0.03)	$ 0.26
Cumulative effect of accounting change	—	—	(0.60)
Basic and diluted net income (loss) per unit after accounting change	$ 0.38	$ (0.03)	$ (0.34)
Weighted average basic and diluted units outstanding	34,376	29,077	25,928

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31, 2001	December 31, 2000
ASSETS		
Current assets		
Cash and cash equivalents	$ 13,084	$ 20,281
Accounts receivable, net		
Trade	33,162	33,801
Affiliates	22,863	1,602
Other current assets	557	633
Total current assets	69,666	56,317
Property, plant and equipment, net	1,103,427	619,238
Investment in processing agreement	119,981	—
Investments in unconsolidated affiliates	34,442	182,734
Other noncurrent assets	29,754	11,182
Total assets	$1,357,270	$869,471
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	$ 14,987	$ 14,726
Affiliates	9,918	2,368
Accrued interest	6,401	3,107
Current maturities of limited recourse term loan	19,000	—
Other current liabilities	4,159	2,171
Total current liabilities	54,465	22,372
Revolving credit facility	300,000	318,000
Long-term debt	425,000	175,000
Limited recourse term loan, less current maturities	76,000	45,000
Other noncurrent liabilities	1,079	394
Total liabilities	856,544	560,766
Commitments and contingencies		
Minority interest	—	(2,366)
Partners' capital		
Limited partners		
Series B preference units; 125,392 units in 2001 and 170,000 units in 2000 issued and outstanding	142,896	175,668
Common units; 39,738,974 units in 2001 and 31,550,314 units in 2000 issued and outstanding	354,019	132,802
Accumulated other comprehensive income allocated to limited partners' interest	(1,259)	—
General partner	5,083	2,601
Accumulated other comprehensive income allocated to general partner's interests	(13)	—
Total partners' capital	500,726	311,071
Total liabilities and partners' capital	$1,357,270	$869,471

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2001	2000	1999
Cash flows from operating activities			
Net income	$ 55,149	$ 20,497	$ 18,817
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	38,649	27,743	30,630
Net loss (gain) on sale of assets	11,367	—	(10,103)
Asset impairment charge	3,921	—	—
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	(8,449)	(22,931)	(32,814)
Distributions from unconsolidated affiliates	35,062	33,960	46,180
Litigation reserve	—	(2,250)	2,250
Other noncash items	4,308	2,237	1,834
Working capital changes, net of effects of acquisitions and non-cash transactions			
Accounts receivable	(41,954)	(17,351)	2,107
Other current assets	125	1,295	366
Accounts payable, accrued interest and other current liabilities	(259)	5,210	(8,507)
Noncurrent receivable from El Paso Corporation	(10,362)	—	—
Other	(173)	—	—
Net cash provided by operating activities	87,384	48,410	50,760
Cash flows from investing activities			
Acquisition and development of oil and natural gas properties	(2,018)	(172)	(3,218)
Additions to pipelines, platforms and facilities	(576,907)	(90,205)	(30,662)
Investments in unconsolidated affiliates	(1,487)	(8,979)	(59,348)
Cash paid for acquisitions, net of cash acquired	(28,414)	(26,476)	(20,351)
Proceeds from sale of assets	109,126	—	26,122
Distributions related to the formation of Deepwater Holdings	—	—	20,000
Other	—	(381)	322
Net cash used in investing activities	(499,700)	(126,213)	(67,135)
Cash flows from financing activities			
Net proceeds from revolving credit facility	559,994	152,043	141,126
Repayments of revolving credit facility	(581,000)	(125,000)	(226,850)
Net proceeds from issuance of long-term debt	243,032	—	168,878
Net proceeds from limited recourse term loan	49,960	43,554	—
Net proceeds from issuance of common units	286,699	100,634	—
Redemption of Series B preference units	(50,000)	—	—
Redemption of publicly held preference units	—	(804)	—
Contributions from general partner	2,843	2,785	603
Distributions to partners	(106,409)	(79,330)	(66,288)
Net cash provided by financing activities	405,119	93,882	17,469
Net (decrease) increase in cash and cash equivalents	(7,197)	16,079	1,094
Cash and cash equivalents at beginning of year	20,281	4,202	3,108
Cash and cash equivalents at end of year	$ 13,084	$ 20,281	$ 4,202

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

(In thousands)

	Series B Preference Units	Series B Preference Unitholders	Preference Units	Preference Unitholders	Common Units	Common Unitholders	General Partner[1]	Total
Partners' capital at December 31, 1998	—	$ —	1,017	$ 7,351	23,350	$ 90,972	$(15,427)	$ 82,896
Cumulative effect of accounting change	—	—	—	3,072	—	(18,499)	15,427	—
Net income[2]	—	—	—	919	—	5,769	12,129	18,817
Acquisition of additional interest in Viosca Knoll	—	—	—	—	2,662	59,792	—	59,792
General partner contribution related to issuance of common units	—	—	—	—	—	—	603	603
Conversion of preference units into common units	—	—	(727)	(7,454)	727	7,454	—	—
Cash distributions	—	—	—	(919)	—	(52,211)	(12,489)	(65,619)
Partners' capital at December 31, 1999	—	—	290	2,969	26,739	93,277	243	96,489
Net income (loss)[2]	—	5,668	—	241	—	(990)	15,578	20,497
Conversion of preference units into common units	—	—	(211)	(2,165)	211	2,165	—	—
Redemption of remaining preference units	—	—	(79)	(804)	—	—	—	(804)
Issuance of common units	—	—	—	—	4,600	100,634	—	100,634
General partner contribution related to the issuance of common units	—	—	—	—	—	—	2,785	2,785
Issuance of Series B preference units	170	170,000	—	—	—	—	—	170,000
Cash distributions				(241)	—	(62,284)	(16,005)	(78,530)
Partners' capital at December 31, 2000	170	175,668	—	—	31,550	132,802	2,601	311,071
Net income[2]	—	17,228	—	—	—	13,260	24,661	55,149
Accumulated other comprehensive income (loss)	—	—	—	—	—	(1,259)	(13)	(1,272)
Issuance of common units	—	—	—	—	8,189	286,699	—	286,699
Unamortized unit option compensation	—	—	—	—	—	2,161	—	2,161
Redemption of Series B preference units	(45)	(50,000)	—	—	—	—	—	(50,000)
General partner contribution related to the issuance of common units	—	—	—	—	—	—	2,843	2,843
Cash distributions	—	—	—	—	—	(80,903)	(25,022)	(105,925)
Partners' capital at December 31, 2001	125	$142,896	—	$ —	39,739	$352,760	$ 5,070	$ 500,726

(1) El Paso Energy Partners Company, a wholly owned subsidiary of El Paso Corporation, owns a one percent general partner interest in us.

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

See accompanying notes.

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

Comprehensive Income

	Year Ended December 31,		
	2001	2000	1999
Net income	$55,149	$20,497	$18,817
Other comprehensive income (loss)	(1,272)	—	—
Total comprehensive income	$53,877	$20,497	$18,817

Accumulated Other Comprehensive Income

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

See accompanying notes.

EL PASO ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

We are a publicly held Delaware master limited partnership established in 1993 for the purpose of providing midstream energy services, including gathering, transportation, fractionation, storage and other related activities for producers of natural gas and oil, onshore and offshore in the Gulf of Mexico. As of December 31, 2001, we had 39,738,974 common units representing limited partner interests and 125,392 Series B preference units representing preference interests outstanding. On that date, the public owned 29,308,140 common units, or 74 percent of our outstanding common units, and El Paso Corporation, through its subsidiaries, owned 10,430,834 common units, or 26 percent of our outstanding common units, all of the 125,392 Series B preference units (with a liquidation value of $143 million) and our one percent general partner interest.

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We account for investments in companies where we have the ability to exert significant influence over, but not control over operating and financial policies, using the equity method of accounting. Prior to May 2001, our general partner's approximate one percent non-managing interest in twelve of our subsidiaries represented the minority interest in our consolidated financial statements. In May 2001, we purchased our general partner's one percent non-managing ownership interests. Our consolidated financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or partners' capital.

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 Standard (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, which may differ from the accounting requirements of our non-regulated entities. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, and other costs and taxes included in, or expected to be included in, future rates.

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

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts which may become uncollectible. Collectibility is reviewed regularly and the allowance is adjusted as necessary, primarily under the specific identification method. At December 31, 2001 and 2000, the allowance was $1.8 and $0.4 million.

Natural Gas Imbalances

Natural gas imbalances result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. These imbalances are settled in kind through a fuel gas and unaccounted for gas tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure. Gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our financial statements.

Property, Plant and Equipment

For our regulated interstate system and storage facility we use the composite (group) method to depreciate regulated property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff, to the total cost of the group, until its net book value equals its estimated salvage value.

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

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

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

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

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

Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depreciation provisions for gathering pipelines, platforms, related facilities and oil and natural gas properties.

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

Asset Impairment

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

Capitalization of Interest

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

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness using the effective interest method. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated.

Revenue Recognition

Revenue from pipeline transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from natural gas sales is recognized upon delivery and was $59.7 million and $34.5 million for the years ended December 31, 2001 and 2000. There were no natural gas sales in 1999. Natural gas sales are included in gathering and transportation services revenue on the accompanying statements of income. Natural gas storage revenues and platform access revenues consist primarily of fixed fees for capacity reservation and some of our transportation contracts on our Viosca Knoll system and our Indian Basin lateral also contain a fixed fee to reserve transportation capacity. These fixed fees are recognized during the month in which the capacity is reserved by the customer, regardless of how much capacity is actually used. Revenue from processing services and fractionation services is recognized in the period the services are provided. Interruptible revenues from natural gas storage, which are generated by providing excess storage capacity, are variable in nature and are recognized when the service is provided.

Environmental Costs

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

Accounting for Price Risk Management Activities

Our business activities expose us to a variety of risks, including commodity price risk and interest rate risk. From time to time we use derivative instruments to manage these risks. Beginning in 2001, we record all derivative instruments on the balance sheet at their fair value under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.*

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

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

During 2001, we entered into cash flow hedges that qualify for SFAS No. 133 treatment. Changes in the fair value of a derivative designated as a cash flow hedge are recorded in accumulated other comprehensive income for the portion of the change in value of the derivative that is effective. The ineffective portion of the derivative is recorded in earnings in the current period. Classification in the income statement of the ineffective portion is based on the income classification of the item being hedged.

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

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

During the normal course of our business, we may enter into contracts that qualify as derivatives under the provisions of SFAS No. 133. As a result, we evaluate our contracts to determine whether derivative accounting is appropriate. Contracts that meet the criteria of a derivative and qualify as "normal purchases" and "normal sales", as those terms are defined in SFAS No. 133, may be excluded from SFAS No. 133 treatment.

Income Taxes

As of December 31, 2001, neither we nor any of our subsidiaries are taxable entities. Tarpon Transmission Company, our only taxable entity in 2000 and 1999, was sold in January 2001, and as a result, we incurred no tax liability in 2001. However, the taxable income or loss resulting from our operations will ultimately be included in the federal and state income tax returns of the general and limited partners. Individual partners will have different investment bases depending upon the timing and price of their acquisition of partnership units. Further, each partner's tax accounting, which is partially dependent upon his tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual partner's tax basis and his share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual partner's tax attributes and the aggregate tax bases cannot be readily determined.

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

Income (Loss) per Unit

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

Basic income (loss) per unit and diluted income (loss) per unit are the same for the years ended December 31, 2001, 2000, and 1999, as the number of potentially dilutive units were so small as not to cause the diluted earnings per unit to be different from the basic earnings per unit. We include the outstanding publicly held preference units in 1999 and 2000 in the basic and diluted net income (loss) per unit calculation as if the publicly held preference units had been converted into common units. As of October 2000, all publicly held preference units have been converted into common units or redeemed.

Comprehensive Income

Our comprehensive income is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income (loss) from our cash flow hedging activities at EPIA.

Unit-Based Compensation

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

Cumulative Effect of Accounting Change

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

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

Business Combinations

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

Goodwill and Other Intangible Assets

In July 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets*. This statement requires that goodwill no longer be amortized but intermittently tested for impairment at least on an annual basis. Other intangible assets are to be amortized over their useful life and reviewed for impairment in accordance with the provisions of SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. An intangible asset with an indefinite useful life can no longer be amortized until its useful life becomes determinable. This statement has various effective dates, the most significant of which is January 1, 2002. Upon adoption of this Statement on January 1, 2002, we will no longer recognize annual amortization expense of approximately $120 thousand on goodwill and indefinite-lived intangible assets. We do not expect the impact of adopting this pronouncement to have a material effect on our financial statements; however, our impairment tests are not yet complete.

Accounting for Asset Retirement Obligations

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

Accounting for the Impairment or Disposal of Long-Lived Assets

In October 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. This statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of this statement are effective for fiscal years beginning after December 15, 2001.

The provisions of this pronouncement will impact any asset dispositions we make after January 1, 2002, including our pending sale of the Prince TLP and the 9 percent overriding royalty interest in the Prince Field.

2. Acquisitions and Dispositions

Midstream Businesses

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

- the 9,400 mile EPGT Texas intrastate pipeline, with a capacity of approximately 5 Bcf/d and average throughput of 3,500 MDth/d during 2001;
- 1,300 miles of gathering systems in the Permian Basin gathering system with a capacity of 465 MMcf/d and average throughput of 341 MDth/d during 2001; and
- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

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

- the sale of our Prince TLP and the 9 percent overriding royalty interest in the Prince Field for approximately $190 million after our repayment of the related limited recourse debt of $95 million;
- the issuance of $6 million in common units; and
- a cash payment of $554 million.

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

NGL Storage Facilities

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

Deepwater Holdings L.L.C. and Chaco Transaction

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

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

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

EPN Texas

In February 2001, we acquired EPN Texas from a subsidiary of El Paso Corporation for $133 million. We funded the acquisition of these assets by borrowing from our revolving credit facility. These assets include more than 600 miles of NGL gathering and transportation pipelines. The NGL pipeline system gathers and transports unfractionated and fractionated products. We also acquired three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGLs into ethane, propane and butane products which are used by refineries and petrochemical plants along the Texas Gulf Coast. We accounted for the acquisition as a purchase and assigned the purchase price to the assets acquired based upon the estimated fair value of the assets as of the acquisition date. We have included the operating results of EPN Texas in our consolidated financial statements from the acquisition date.

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the twelve months ended December 31, 2001 and 2000, as if we acquired EPN Texas, the Chaco plant and the remaining 50 percent interest in Deepwater Holdings on January 1, 2000:

	2001	2000
	(in thousands, except per unit amounts)	
Operating revenues	$269,681	$222,080
Operating income	$101,406	$ 96,197
Net income allocated to limited partners	$ 39,157	$ 15,790
Basic and diluted net income per unit	$ 1.14	$ 0.54

Gulf of Mexico Assets

In accordance with an FTC order related to El Paso Corporation's merger with The Coastal Corporation, we, along with Deepwater Holdings, agreed to sell several of our offshore Gulf of Mexico assets to third parties in January 2001. Total consideration received for these assets was approximately $163 million consisting of approximately $109 million for the assets we sold and approximately $54 million for the assets Deepwater Holdings sold. The offshore assets sold include interests in Stingray, 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 the next three years and $2 million in the first quarter of 2004. From this additional consideration, we realized income of approximately $25 million in the first quarter of 2001, which has been reflected in other income in the accompanying statements of income.

Crystal Gas Storage

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

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

El Paso Intrastate-Alabama Pipeline System

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

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

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

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

Deepwater Holdings

In June 1999, we acquired additional interests in the HIOS, UTOS and East Breaks systems through our acquisition of Natoco, Inc. and Naloco, Inc. for $51 million. As part of the transaction, we also assumed operations of the Stingray system, the Stingray Offshore separation facility and the West Cameron dehydration facility in November 1999. The purchase price exceeded the book value of net assets acquired by approximately $48 million. This excess cost is being amortized on a straight-line basis over the estimated lives of the acquired assets, which approximates 30 years.

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

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

- retire existing debt of Stingray and Western Gulf, the parent company of East Breaks and HIOS;
- fund a one-time distribution of $20 million to each of the equity partners;
- provide funds for the remaining construction costs of the East Breaks system and any future system expansions; and
- provide for other working capital needs of Deepwater Holdings.

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

	1999
	(In thousands, except per unit amounts)
Operating revenues	$93,071
Operating income	$39,841
Net loss allocated to limited partners before accounting change	$ (7,364)
Basic and diluted net loss per unit before cumulative effect of accounting change	$ (0.28)

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

Viosca Knoll

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

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

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

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

	1999
	(In thousands, except per unit amounts)
Operating revenues	$104,951
Operating income	$ 48,710
Net income allocated to limited partners before accounting change	$ 8,675
Basic and diluted net income per unit before cumulative effect of accounting change	$ 0.32

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

3. Investments in Unconsolidated Affiliates

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. As of December 31, 2001, the carrying amount of our equity investment exceeded the underlying equity in net assets by approximately $3.0 million. This difference is being amortized on a straight-line basis over the estimated life of the underlying net assets of our investment. With our adoption of SFAS No. 142 on January 1, 2002, we will no longer amortize this excess amount but will intermittently test (no less than annually) these amounts for impairment under the provisions of SFAS No. 142. Summarized financial information for these investments is as follows:

	As of or for the Year Ended December 31, 2001				
	Deepwater Holdings[(a)]	Poseidon	Divested Investments[(b)]	Other	Total
			(In thousands)		
End of period ownership interest	100%	36%	—	50%	
Operating results data:					
Operating revenues	$ 40,933	$ 71,516	$1,982	$ 145	
Other income (loss)	—	394	(85)		
Operating expenses	(16,740)	(2,701)	(590)	(73)	
Depreciation	(8,899)	(10,552)	(953)		
Other (expenses) income	(5,868)	(7,668)	222	(22)	
Loss on sale of assets	(21,453)	—	—		
Net income (loss)	$(12,027)	$ 50,989	$ 576	$ 50	
Our share:					
Allocated income (loss)[(c)]	$ (9,925)	$ 18,356	$ 148	$ 25	
Adjustments[(d)]	—	(146)	(9)	—	
Earnings (loss) from unconsolidated affiliates	$ (9,925)	$ 18,210	$ 139	$ 25	$ 8,449
Allocated distributions	$ 12,850	$ 22,212	$ —	$ —	$35,062
Financial position data:					
Current assets		$ 91,367		$ 177	
Noncurrent assets		226,570		—	
Current liabilities		80,365		33	
Long-term debt		150,000		—	

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

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

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

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

	As of or for the Year Ended December 31, 2000				
	Deepwater Holdings	Poseidon	Divested Investments[(a)]	Other	Total
			(In thousands)		
End of period ownership interest	50%	36%	25.67%	50%	
Operating results data:					
Operating revenues	$ 67,122	$ 65,158	$ 26,478	$ 110	
Other income	532	639	2,301	—	
Operating expenses	(25,279)	(24,398)	(5,205)	(51)	
Depreciation	(18,138)	(10,754)	(10,363)	—	
Other expenses	(10,711)	(11,683)	(432)	(19)	
Net income	$ 13,526	$ 18,962	$ 12,779	$ 40	
Our share:					
Allocated income	$ 6,763	$ 6,826	$ 3,281	$ 20	
Adjustments[(b)]	507	5,892	(358)	—	
Earnings from unconsolidated affiliates	$ 7,270	$ 12,718	$ 2,923	$ 20	$22,931
Allocated distributions	$ 13,550	$ 13,532	$ 6,878	$ —	$33,960
Financial position data:					
Current assets	$ 46,128	$125,325	$ 4,375	$ 111	
Noncurrent assets	237,416	239,030	247,554	—	
Current liabilities	39,962	264,776	1,423	27	
Long-term debt	157,000	—	—	—	
Other noncurrent liabilities	9,517	1,297	—	—	

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

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

	As of or for the Year Ended December 31, 1999					
	Deepwater Holdings[(a)]	Poseidon	Divested Investments[(b)]	Viosca Knoll[(c)]	Other	Total
			(In thousands)			
End of period ownership interest	50%	36%	25.67%	99%	50%	
Operating results data:						
Operating revenue	$ 59,965	$ 76,160	$ 26,620	$12,338	$ 35	
Other income	2,203	403	2,328	31	—	
Operating expenses	(31,081)	(8,774)	(5,164)	(925)	(18)	
Depreciation	(13,629)	(6,172)	(11,195)	(1,752)	—	
Other expenses	(2,918)	(9,133)	(350)	(1,973)	—	
Net income	$ 14,540	$ 52,484	$ 12,239	$ 7,719	$ 17	
Our share:						
Allocated income	$ 6,591	$ 18,894	$ 3,142	$ 3,860	$ 8	
Adjustments[(d)]	1,173	(7)	(839)	—	(8)	
Earnings from unconsolidated affiliates	$ 7,764	$ 18,887	$ 2,303	$ 3,860	$ —	$32,814
Allocated distributions	$ 15,601	$ 18,191	$ 5,906	$ 6,350	$ 132	$46,180
Financial position data:						
Current assets	$ 34,334	$171,720	$ 7,934		$ 376	
Noncurrent assets	208,939	243,971	245,164		—	
Current liabilities	32,727	159,359	5,157		44	
Long-term debt	122,000	150,000	—		—	
Other noncurrent liabilities	41	322	—		—	

(a) Deepwater Holdings was formed in September 1999 and owned 100 percent of Stingray, HIOS, UTOS, and the West Cameron dehydration facility. The operating results are the pro forma results of Deepwater Holding and each of its subsidiaries, Stingray, HIOS, UTOS and the West Cameron dehydration facility, as if formation of Deepwater Holdings and its acquisitions of Stingray, HIOS, UTOS and the West Cameron dehydration facility had occurred January 1, 1999.

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

(c) The information presented for Viosca Knoll as an equity investment is through May 31, 1999. On June 1, 1999, we began consolidating the results of Viosca Knoll as a result of acquiring an additional 49 percent interest in the system.

(d) We recorded adjustments primarily for purchase price adjustments in accordance with APB Opinion No. 16, except for Stingray which resulted from changes in estimates of reserves for uncollectable revenues.

4. Property, Plant and Equipment

Our property, plant and equipment consisted of the following:

	December 31,	
	2001	2000
	(In thousands)	
Property, plant and equipment, at cost		
Pipelines	$ 856,335	$239,920
Platforms and facilities	281,600	127,639
Processing plant	138,450	—
Oil and natural gas properties	159,375	156,320
Storage facilities	156,800	147,294
Construction work-in-progress	99,335	127,811
	1,691,895	798,984
Less accumulated depreciation and depletion	588,468	179,746
Total property, plant and equipment, net	$1,103,427	$619,238

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 Gathering and Transportation segment.

5. Investment in Processing Agreement

As part of our October 2001 Chaco transaction, we paid $121.5 million to El Paso Field Services for a 20-year fee-based processing agreement. This amount is being amortized on a straight-line basis over the life of the agreement. Under the processing agreement, all previously uncommitted volumes on El Paso Field Services' San Juan Gathering System are dedicated to the Chaco plant. As part of the agreement, natural gas delivered to the Chaco plant by El Paso Field Services will have a processing priority over other natural gas.

6. Financing Transactions

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

Senior Subordinated Notes

In May 2001, we issued $250 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. These notes bear interest at a rate of 8 1/2% per year, payable semi-annually in June and December, and mature in June 2011. Proceeds of approximately $243 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility.

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

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

Revolving Credit Facility

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

Limited Recourse Term Loan

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

Other Credit Facilities

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

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

Interest Expense

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

	2001	2000	1999
		(In millions)	
Interest expense incurred	$54.9	$51.1	$37.1
Interest capitalized	11.8	4.0	1.8
Net interest expense	$43.1	$47.1	$35.3

7. Financial Instruments

Fair Value of Financial Instruments

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

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Liabilities:				
Revolving credit facility	$300	$300	$ 318	$ 318
Limited recourse term loan	95	95	45	45
10 3/8% Senior Subordinated Notes	175	186	175	185
8 1/2% Senior Subordinated Notes	250	253	N/A	N/A
Non-trading derivative instruments				
Commodity swap and forward contracts	$ 1	$ 1	$ —	$ —

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

	2001			2000		
	Notional Volume			Notional Volume		
	Buy	Sell	Maximum Term in Years	Buy	Sell	Maximum Term in Years
Commodity						
Natural Gas (MDth)	765	—	<1	—	—	N/A

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

8. Partners’ Capital

General

As of December 31, 2001, we had 39,738,974 common units outstanding. Common units totaling 29,308,140 are owned by the public, representing a 74 percent limited partner interest in us. As of December 31, 2001, El Paso Corporation, through its subsidiaries, owned 10,430,834 common units, or

26 percent of our outstanding common units, 125,392 Series B preference units (with a liquidation value of $143 million) and our one percent general partner interest.

Offering of Common Units

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

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

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

Conversion and Redemption of Preference Units

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

Series B Preference Units

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

Cash Distributions

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

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

Month Paid	Common Unit	General Partner
	(Per unit)	(In millions)
February	$0.5500	$4.6
May	$0.5750	$5.8
August	$0.5750	$5.8
November	$0.6125	$8.1

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

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

Option Plans

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

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

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

	2001		2000		1999	
	# Units of Underlying Options	Weighted Average Exercise Price	# Units of Underlying Options	Weighted Average Exercise Price	# Units of Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of year	925,500	$27.15	937,500	$27.16	933,000	$27.19
Granted	1,016,500	35.00	3,000	25.56	4,500	21.58
Exercised	307,500	27.17	—	—	—	—
Forfeited	—	—	7,500	27.19	—	—
Canceled	20,000	27.19	7,500	27.19	—	—
Outstanding at end of year	1,614,500	$32.09	925,500	$27.15	937,500	$27.16
Options exercisable at end of year	606,500	$27.22	925,500	$27.15	687,500	$27.15

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

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

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

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

	Options Outstanding			Options Exercisable	
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	598,000	6.6	$27.18	598,000	$27.18
$27.80 to $39.72	1,016,500	9.7	$34.97	8,500	$32.71
$19.86 to $39.72	1,614,500	8.6	$32.09	606,500	$27.22

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

	December 31, 2001		December 31, 2000		December 31, 1999	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
			(In thousands, except per unit amounts)			
SFAS No. 123 charge, pretax	$ —	$ 311	$ —	$ 211	$ —	$ 890
Net income (loss) allocated to the limited partners	$13,260	$12,949	$ (749)	$ (960)	$(8,739)	$(9,629)
Basic and diluted income (loss) per unit	$ 0.38	$ 0.38	$(0.03)	$(0.03)	$ (0.34)	$ (0.37)

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

9. Related Party Transactions

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

	2001	2000	1999
		(In thousands)	
Revenues received from related parties:			
Gathering and transportation services	$12,674	$ 9,356	$ —
Liquid transportation and handling services	32,382	—	—
Platform services	8,188	146	990
Storage services	2,324	1,268	—
Oil and natural gas sales	672	15,722	29,778
	$56,240	$26,492	$30,768
Expenses paid to related parties:			
Purchased natural gas costs	$34,646	$16,751	$ —
Operating expenses	34,499	22,817	13,494
	$69,145	$39,568	$13,494
Reimbursements received from related parties:			
Operating expenses	$11,499	$20,543	$ 2,377

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

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

	(In thousands)
Accounts receivable affiliate	$ 7,745
Other noncurrent assets	10,362
	$18,107

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

	2001	2000	1999
		(In thousands)	
Revenues received from related parties:			
El Paso Corporation			
Merchant Energy North America Company	$ 9,865	$21,832	$29,778
El Paso Production Company	13,054	4,303	—
Southern Natural Gas Company	156	155	—
Tennessee Gas Pipeline Company	748	56	—
El Paso Field Services	32,382	—	—
Unconsolidated Subsidiaries			
Manta Ray Offshore(1)	35	146	—
Viosca Knoll Gathering Company(2)	—	—	990
	$56,240	$26,492	$30,768
Purchased natural gas costs paid to related parties:			
El Paso Corporation			
Merchant Energy North America Company	$28,047	$14,454	$ —
El Paso Production Company	6,412	2,160	—
Southern Natural Gas Company	187	137	—
	$34,646	$16,751	$ —
Operating expenses paid to related parties:			
El Paso Corporation			
El Paso Field Services	$33,965	$22,265	$11,726
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company	534	552	944
Viosca Knoll Gathering Company(2)	—	—	824
	$34,499	$22,817	$13,494
Reimbursements received from related parties:			
Unconsolidated Subsidiaries			
Deepwater Holdings(3)	$ 9,399	$20,344	$ 1,820
Poseidon Oil Pipeline Company	2,100	—	—
Manta Ray Offshore(1)	—	199	515
Viosca Knoll Gathering Company(2)	—	—	42
	$11,499	$20,543	$ 2,377

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

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

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

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

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

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

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

In October 1999, we farmed out our working interest in the Prince Field to El Paso Production Company. Under the terms of the farmout agreement, our net overriding royalty interest in the Prince Field increased to a weighted average of approximately nine percent. El Paso Production Company began production on the Prince Field in September 2001. For the year ended December 31, 2001, we recorded approximately $0.7 million in revenues related to our overriding royalty interest in the Prince Field.

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

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

Expenses paid to related parties

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

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

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

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

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

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

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

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

10. Commitments and Contingencies

Legal Proceedings

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

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

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

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

Environmental

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

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

Regulatory Matters

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

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

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

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

11. Accounting for Hedging Activities

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

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

12. Supplemental Disclosures to the Statement of Cash Flows

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

	Year ended December 31,		
	2001	2000	1999
		(In thousands)	
Interest	$41,020	$46,768	$31,696

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

	Year ended December 31,		
	2001	2000	1999
		(In thousands)	
Acquisition of additional 50 percent interest in Deepwater Holdings			
Working capital acquired	$7,494	$ —	$ —
Acquisition of Crystal natural gas storage businesses			
Issuance of Series B preference units	—	170,000	—
Working capital acquired	—	220	—
Acquisition of EPIA			
Working capital acquired	—	(1,673)	—
Acquisition of additional ownership interest in Viosca Knoll			
Issuance of common units	—	—	59,792
Working capital acquired	—	—	(2,400)

13. Major Customers

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

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

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

14. Business Segment Information:

We segregate our business activities into five distinct operating segments:

• Natural Gas Gathering and Transportation;

• Liquid Transportation and Handling;

• Platforms;

• Natural Gas Storage; and

• Oil and Natural Gas Production.

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 Liquid Transportation and Handling. This segment also includes the liquid transportation services of the Allegheny and Poseidon oil pipelines which were previously reflected in the Natural Gas Gathering and Transportation 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 Platforms. The Prince TLP processes oil and natural gas from the Prince Field. First production flowed through the facility in September 2001. This segment also 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 Gathering and Transportation segment.

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

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

	Natural Gas Gathering & Transportation	Liquid Transportation & Handling Services	Platform Services	Natural Gas Storage	Oil and Natural Gas Production	Intersegment Eliminations & Other(1)	Total
				(in thousands)			
For the Year Ended December 31, 2001							
Revenue from external customers	$ 93,550	$ 39,460	$ 23,538	$ 19,373	$26,310	$ —	$ 202,231
Intersegment revenue	381	—	12,620	—	—	(13,001)	—
Depreciation, depletion and amortization	10,207	7,284	7,142	5,605	7,567	844	38,649
Asset impairment charge	3,921	—	—	—	—	—	3,921
Operating income	21,870	25,466	25,582	9,548	2,376	(12,271)	72,571
Earnings (loss) from unconsolidated affiliates	(9,761)	18,210	—	—	—	—	8,449
EBIT	26,985	43,676	24,950	9,568	2,376	(9,176)	98,379
Performance cash flows(2)	49,549	54,962	32,726	15,173	9,943	(913)	161,440
Assets	365,976	393,408	267,864	226,991	45,345	57,686	1,357,270
For the Year Ended December 31, 2000							
Revenue from external customers	$ 63,499	$ 8,307	$ 13,875	$ 6,182	$20,552	$ —	$ 112,415
Intersegment revenue	629	—	12,958	—	—	(13,587)	—
Depreciation, depletion and amortization	8,062	1,391	4,445	1,868	11,280	697	27,743
Operating income (loss)	26,183	6,876	22,491	2,190	(6,956)	(8,733)	42,051
Earnings from unconsolidated affiliates	10,213	12,718	—	—	—	—	22,931
EBIT	37,004	21,322	22,491	2,193	(6,956)	(8,695)	67,359
Performance cash flows(2)	54,823	28,528	24,686	4,061	2,705	(7,698)	107,105
Assets	345,309	65,734	200,166	176,420	53,417	28,425	869,471
For the Year Ended December 31, 1999							
Revenue from external customers	$ 20,282	$ 2,029	$ 11,383	$ —	$29,965	$ —	$ 63,659
Intersegment revenue	693	—	12,500	—	—	(13,193)	—
Depreciation, depletion and amortization	6,335	643	4,082	—	18,894	676	30,630
Operating income (loss)	9,694	1,155	15,962	—	(6,545)	(9,639)	10,627
Earnings from unconsolidated affiliates	13,927	18,887	—	—	—	—	32,814
EBIT	33,730	20,042	15,962	—	(6,545)	(9,287)	53,902
Performance cash flows(2)	44,018	19,989	22,294	—	13,967	(8,963)	91,305
Assets	319,345	57,893	123,382	—	67,885	15,080	583,585

(1) Represents intersegment eliminations and other income or assets not associated with our segment activities.

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

15. Guarantor Financial Information

In May 2001, we purchased our general partner’s 1.01 percent non-managing ownership interest in twelve of our subsidiaries for $8 million. As a result of this acquisition, all of our subsidiaries, but not our joint ventures, are wholly owned by us. Our revolving credit facility is guaranteed by each of our subsidiaries (excluding our Argo, L.L.C. and Argo I, L.L.C. subsidiaries) and is collateralized by our management agreement, substantially all of our assets, and our general partner’s one percent general partner interest. In addition, all of our senior subordinated notes are guaranteed by all of our subsidiaries except Argo and Argo I. We are providing the following condensed consolidating financial information of us (as the issuer) and our subsidiaries as if our current organizational structure were in place for all periods presented. The consolidating eliminations column on our balance sheets eliminate our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year Ended December 31, 2001

	Issuer	Non-guarantor Subsidiaries(1)	Guarantor Subsidiaries	Consolidated Total
		(In thousands)		
Operating revenues				
Gathering and transportation services	$ —	$ —	$ 93,550	$ 93,550
Liquid transportation and handling	—	—	39,460	39,460
Platform services	—	8,153	15,385	23,538
Natural gas storage services	—	—	19,373	19,373
Oil and natural gas sales	—	—	26,310	26,310
	—	8,153	194,078	202,231
Operating expenses				
Cost of natural gas	—	—	51,542	51,542
Operations and maintenance, net	(200)	2,269	33,479	35,548
Depreciation, depletion and amortization	323	2,988	35,338	38,649
Asset impairment charge	—	—	3,921	3,921
	123	5,257	124,280	129,660
Operating income (loss)	(123)	2,896	69,798	72,571
Other income (loss)				
Earnings from unconsolidated affiliates	—	—	8,449	8,449
Net loss on sales of assets	(10,941)	—	(426)	(11,367)
Other income	28,492	—	234	28,726
	17,551	—	8,257	25,808
Income before interest, income taxes and other charges	17,428	2,896	78,055	98,379
Interest and debt income (expense)	15,328	(1,588)	(56,870)	(43,130)
Minority interest	—	—	(100)	(100)
Net income	$ 32,756	$ 1,308	$ 21,085	$ 55,149

(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				
Gathering and transportation services	$ —	$ —	$ 63,499	$ 63,499
Liquid transportation and handling	—	—	8,307	8,307
Platform services	—	—	13,875	13,875
Natural gas storage services	—	—	6,182	6,182
Oil and natural gas sales	—	—	20,552	20,552
	—	—	112,415	112,415
Operating expenses				
Cost of natural gas	—	—	28,160	28,160
Operations and maintenance, net	(323)	—	14,784	14,461
Depreciation, depletion and amortization	151	—	27,592	27,743
	(172)	—	70,536	70,364
Operating income	172	—	41,879	42,051
Other income				
Earnings from unconsolidated affiliates	—	—	22,931	22,931
Other income	311	—	2,066	2,377
	311	—	24,997	25,308
Income before interest, income taxes and other charges	483	—	66,876	67,359
Interest and debt expense	(70)	(252)	(46,750)	(47,072)
Minority interest	—	—	(95)	(95)
Income tax benefit	—	—	305	305
Net income (loss)	$ 413	$(252)	$ 20,336	$ 20,497

(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, 1999

	Issuer	Guarantor Subsidiaries	Consolidated Total
		(In thousands)	
Operating revenues			
Gathering and transportation services	$ —	$ 20,282	$ 20,282
Liquid transportation and handling	—	2,029	2,029
Platform services	—	11,383	11,383
Oil and natural gas sales	—	29,965	29,965
	—	63,659	63,659
Operating expenses			
Operations and maintenance, net	—	22,402	22,402
Depreciation, depletion and amortization	28	30,602	30,630
	28	53,004	53,032
Operating income (loss)	(28)	10,655	10,627
Other income			
Earnings from unconsolidated affiliates	—	32,814	32,814
Net gain on sales of assets	—	10,103	10,103
Other income	218	140	358
	218	43,057	43,275
Income before interest, income taxes and other charges	190	53,712	53,902
Interest and debt expense	—	(35,323)	(35,323)
Minority interest	—	(197)	(197)
Income tax benefit	—	435	435
Net income	$190	$ 18,627	$ 18,817

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2001

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 7,406	$ 2,571	$ 3,107	$ —	$ 13,084
Accounts receivable, net					
Trade	—	191	32,971	—	33,162
Affiliate	970,933	2,130	2,150	(952,350)	22,863
Other current assets	2,375	264	(2,082)	—	557
Total current assets	980,714	5,156	36,146	(952,350)	69,666
Property, plant and equipment, net	2,371	152,734	948,322	—	1,103,427
Investment in processing agreement	—	—	119,981	—	119,981
Investments in unconsolidated affiliates	—	—	34,442	—	34,442
Investments in consolidated affiliates	51,960	—	45,849	(97,809)	—
Other noncurrent assets	196,777	1,089	1,887	(169,999)	29,754
Total assets	$1,231,822	$158,979	$1,186,627	$(1,220,158)	$1,357,270
Current liabilities					
Accounts payable					
Trade	$ 587	$ 3,859	$ 10,541	$ —	$ 14,987
Affiliate	—	13,568	948,700	(952,350)	9,918
Accrued interest	5,698	703	—	—	6,401
Current maturities of limited recourse term loan	—	19,000	—	—	19,000
Other current liabilities	(189)	—	4,348	—	4,159
Total current liabilities	6,096	37,130	963,589	(952,350)	54,465
Revolving credit facility	300,000	—	—	—	300,000
Long-term debt	425,000	—	—	—	425,000
Limited recourse term loan, less current maturities	—	76,000	—	—	76,000
Other noncurrent liabilities	—	—	171,078	(169,999)	1,079
Partners' capital	500,726	45,849	51,960	(97,809)	500,726
Total liabilities and partners' capital	$1,231,822	$158,979	$1,186,627	$(1,220,158)	$1,357,270

(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2000

	Issuer	Non-guarantor Subsidiaries(1)	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 18,865	$ 1,416	$ —	$ —	$ 20,281
Accounts receivable, net					
Trade	—	—	39,270	(5,469)	33,801
Affiliate	620,780	(875)	1,602	(619,905)	1,602
Other current assets	390	—	243	—	633
Total current assets	640,035	541	41,115	(625,374)	56,317
Property, plant and equipment, net	1,798	88,356	529,084	—	619,238
Investments in unconsolidated affiliates	—	—	182,734	—	182,734
Investments in consolidated affiliates	156,175	—	44,542	(200,717)	—
Other noncurrent assets	9,498	1,445	239	—	11,182
Total assets	$807,506	$90,342	$797,714	$(826,091)	$869,471
Current liabilities					
Accounts payable					
Trade	$ 1,585	$ 508	$ 18,102	$ (5,469)	$ 14,726
Affiliate	—	—	622,273	(619,905)	2,368
Accrued interest	2,815	292	—	—	3,107
Other current liabilities	(965)	—	3,136	—	2,171
Total current liabilities	3,435	800	643,511	(625,374)	22,372
Revolving credit facility	318,000	—	—	—	318,000
Long-term debt	175,000	—	—	—	175,000
Limited recourse term loan	—	45,000	—	—	45,000
Other noncurrent liabilities	—	—	394	—	394
Minority interest	—	—	(2,366)	—	(2,366)
Partners' capital	311,071	44,542	156,175	(200,717)	311,071
Total liabilities and partners' capital	$807,506	$90,342	$797,714	$(826,091)	$869,471

(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

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
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation, depletion and amortization	323	2,988	35,338	38,649
Net loss on sales of assets	10,941	—	426	11,367
Asset impairment charge	—	—	3,921	3,921
Distributed earnings of unconsolidated affiliates				
Earnings from unconsolidated affiliates	—	—	(8,449)	(8,449)
Distributions from unconsolidated affiliates	—	—	35,062	35,062
Other noncash items	3,155	318	835	4,308
Working capital changes, net of effects of acquisitions and non-cash transactions	(9,740)	385	(43,268)	(52,623)
Net cash provided by operating activities	37,435	4,999	44,950	87,384
Cash flows from investing activities				
Acquisitions and development of oil and natural gas properties	—	—	(2,018)	(2,018)
Additions to pipelines, platforms and facilities	(896)	(67,367)	(508,644)	(576,907)
Investments in unconsolidated affiliates	—	—	(1,487)	(1,487)
Cash paid for acquisitions, net of cash acquired	—	—	(28,414)	(28,414)
Proceeds from sale of assets	89,162	—	19,964	109,126
Net cash provided by (used in) investing activities	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
Net proceeds from limited recourse term loan	—	49,960	—	49,960
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	(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

(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

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
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation, depletion and amortization	151	—	27,592	27,743
Distributed earnings of unconsolidated affiliates				
Earnings from unconsolidated affiliates	—	—	(22,931)	(22,931)
Distributions from unconsolidated affiliates	—	—	33,960	33,960
Litigation reserve	(2,250)	—	—	(2,250)
Other noncash items	2,964	—	(727)	2,237
Working capital changes, net of effects of acquisitions and non-cash transactions	(285)	800	(11,361)	(10,846)
Net cash provided by operating activities	993	548	46,869	48,410
Cash flows from investing activities				
Acquisitions and development of oil and natural gas properties	—	—	(172)	(172)
Additions to pipelines, platforms and facilities	(1,811)	(88,356)	(38)	(90,205)
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	(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 limited recourse term loan	—	43,554	—	43,554
Net proceeds from issuance of common units	100,634	—	—	100,634
Advances with affiliates	(34,765)	45,670	(10,905)	—
Redemption of publicly held preference units	(804)	—	—	(804)
Contribution from general partner	2,785	—	—	2,785
Distributions to partners	(78,529)	—	(801)	(79,330)
Net cash provided by (used in) financing activities	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

(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, 1999

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

16. Supplemental Oil and Natural Gas Information (Unaudited):

Oil and Natural Gas Reserves

The following table represents our net interest in estimated quantities of proved developed and proved undeveloped reserves of crude oil, condensate and natural gas and changes in such quantities at year end 2001, 2000 and 1999. Estimates of our reserves at December 31, 2001, 2000 and 1999, have been made by the independent engineering consulting firm, Netherland, Sewell & Associates, Inc. except for the Prince Field for 2001, which was prepared by El Paso Production Company, our affiliate and operator of the Prince Field. Net proved reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. 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.

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

	Oil/Condensate MBbls(1)	Natural Gas MMcf(1)
Proved reserves — January 1, 1999	1,578	28,884
Revision of previous estimates	251	623
Extension, Discoveries, and other Additions	1	218
Production	(357)	(12,211)
Proved reserves — December 31, 1999	1,473	17,514
Revision of previous estimates	23	1,171
Production	(295)	(7,185)
Proved reserves — December 31, 2000	1,201	11,500
Revision of previous estimates	1,852	5,913
Production	(345)	(4,172)
Proved reserves — December 31, 2001	2,708	13,241

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

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

	Oil (barrels)		Natural Gas (Mcf)	
	Proved Developed	Proved Undeveloped	Proved Developed	Proved Undeveloped
	(In thousands)			
Garden Banks Block 72	277	—	1,900	—
Garden Banks Block 117	1,065	—	1,556	—
Viosca Knoll Block 817	12	—	2,216	2,437
West Delta Block 35	13	—	3,473	—
Prince Field	983	358	1,239	420
Total	2,350	358	10,384	2,857

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

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

Future Net Cash Flows

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

In our opinion, this standardized measure is not a representative measure of fair market value, and the standardized measure presented for our proved oil and natural gas reserves is not representative of the reserve value. The standardized measure is intended only to assist financial statement users in making comparisons between companies.

	December 31,		
	2001	2000	1999
		(In thousands)	
Future cash inflows	$ 80,603	$136,658	$ 69,719
Future production costs	(14,292)	(15,853)	(14,530)
Future development costs	(10,530)	(11,531)	(10,681)
Future net cash flows	55,781	109,274	44,508
Annual discount at 10% rate	(11,992)	(19,525)	(7,990)
Standardized measure of discounted future net cash flows	$ 43,789	$ 89,749	$ 36,518

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	$45,478	$10,303	$55,781
Present value of estimated future net cash flows from proved reserves before income taxes, discounted at 10%	$35,732	$ 8,057	$43,789

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

	2001	2000	1999
		(In thousands)	
Beginning of year	$ 89,749	$ 36,518	$ 26,672
Sales and transfers of oil and natural gas produced, net of production costs	(34,834)	(33,203)	(22,154)
Net changes in prices and production costs	(55,657)	119,457	29,901
Extensions, discoveries and improved recovery, less related costs	—	—	544
Oil and natural gas development costs incurred during the year	2,018	172	615
Changes in estimated future development costs	535	(511)	(1,098)
Revisions of previous quantity estimates	38,090	7,846	5,124
Accretion of discount	8,975	3,652	2,666
Changes in production rates, timing and other	(5,087)	(44,182)	(5,752)
End of year	$ 43,789	$ 89,749	$ 36,518

Development, Exploration, and Acquisition Expenditures

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

	2001	2000	1999
		(In thousands)	
Development costs	$2,018	$172	$3,018
Capitalized interest	—	—	200
Total capital expenditures	$2,018	$172	$3,218

Capitalized Costs

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

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

Results of operations

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

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

17. Supplemental Quarterly Financial Information:

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

	Quarter Ended (Unaudited)				
	March 31	June 30	September 30	December 31	Year
	(In thousands, except per unit data)				
2001					
Operating revenues	$54,502	$44,987	$43,126	$59,616	$202,231
Operating income	13,609	16,312	18,107	24,543	72,571
Net income	12,973	11,844	12,037	18,295	55,149
Net income allocated to general partner	4,695	5,904	5,814	8,248	24,661
Net income allocated to Series B preference unitholders	4,322	4,464	4,538	3,904	17,228
Net income allocated to limited partners	3,956	1,476	1,685	6,143	13,260
Basic and diluted net income per unit	0.12	0.04	0.05	0.17	0.38
Distributions declared per common unit	0.5500	0.5750	0.5750	0.6125	2.3125
Weighted average number of units outstanding	32,471	34,070	34,245	36,209	34,376
2000					
Operating revenues	$18,950	$26,812	$29,642	$37,011	$112,415
Operating income	9,394	13,419	10,032	9,206	42,051
Net income	1,939	8,367	4,862	5,329	20,497
Net income allocated to general partner	3,232	3,622	4,114	4,610	15,578
Net income allocated to Series B preference unitholders	—	—	1,417	4,251	5,668
Net (loss) income allocated to limited partners	(1,293)	4,745	(669)	(3,532)	(749)
Basic and diluted net (loss) income per unit	(0.05)	0.18	(0.02)	(0.11)	(0.03)
Distributions declared per common unit	0.5250	0.5375	0.5375	0.5500	2.1500
Distributions declared per preference unit	0.2750	0.2750	0.2750	—	0.8250
Weighted average number of units outstanding	27,029	27,029	31,229	31,550	29,077

REPORT OF INDEPENDENT ACCOUNTANTS

To the Unitholders of El Paso Energy Partners, L.P.

and the Board of Directors and Stockholder of
El Paso Energy Partners Company, as General Partner:

In our opinion, the consolidated financial statements listed in the index appearing under Item 14(a)1. on page 111 present fairly, in all material respects, the financial position of El Paso Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As disclosed in Note 1 to the consolidated financial statements, the Partnership changed its method for allocating net income to its partners in 1999.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 28, 2002

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 a subsidiary of El Paso Corporation under a management agreement. We reimburse our general partner for reasonable general and administrative expenses, and other reasonable expenses, incurred by our general partner and its affiliates, on our behalf.

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 February 27, 2002, no officer or director has established a trading plan. However, we intend to disclose the name of any officer or director who establishes a trading plan in compliance with Rule 10b5-1 in future filings with the SEC.

Directors and Executive Officers of our General Partner

The following table sets forth certain information as of February 27, 2002, 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, El Paso Energy Partners Holding Company, 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.

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)
William A. Wise	56	Director and Chairman of the Board
Robert G. Phillips	47	Director and Chief Executive Officer
James H. Lytal	44	Director and President
H. Brent Austin	47	Director and Executive Vice President
D. Mark Leland	40	Senior Vice President and Controller
Keith B. Forman	43	Vice President and Chief Financial Officer
Michael B. Bracy	60	Director
H. Douglas Church	64	Director
Kenneth L. Smalley	72	Director
Malcolm Wallop	69	Director

Mr. Wise has served as Director and Chairman of the Board of our general partner since August 1998. He has served as Chief Executive Officer of El Paso Corporation since January 1990 and has served as Chairman of El Paso Corporation’s board of directors from January 1994 until October 1999 and from January 2001 to present. Mr. Wise became President of El Paso Corporation in July 1998 and also served in that capacity from January 1990 to April 1996. Mr. Wise is a member of the Board of Directors of Praxair, Inc. and is Chairman of the Board of El Paso Tennessee Pipeline Co.

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. 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. Austin has served as a Director of our general partner and as Executive Vice President for us and our general partner since August 1998. Mr. Austin has served as an Executive Vice President of El Paso Corporation since May 1995. He has been Chief Financial Officer of El Paso Corporation since April 1992. Prior to that period, he served in various positions with Burlington Resources, Inc.

Mr. Leland has served as Senior Vice President and Controller for us and our general partner since July 2000 and as Vice President of El Paso Field Services Company since September 1997. He served 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. 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. From December 1977 to October 1984, Mr. Bracy held various executive financial positions with El Paso Corporation. Prior to December 1977, Mr. Bracy served in various capacities with The Chase Manhattan Bank. Mr. Bracy is a member of the Board of Directors of Itron, Inc.

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 Boys and Girls Country of Houston, Inc. (Chairman).

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 2000 and is currently a member of the Board of Directors of El Paso Tennessee Pipeline Co.

Mr. Wallop has served as a Director of our general partner since August 1998 and as a Director of El Paso Corporation since January 1995. Since January 1995, Mr. Wallop has served as President for

Frontiers of Freedom Foundation, a political foundation. For eighteen years prior to 1995, Mr. Wallop was a member of the United States Senate. He is a member of the Board of Directors of Hubbell Inc. and Sheridan State Bank.

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 (i) 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; (ii) 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 (iii) and 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. At February 8, 2002, 76,910 units remain unissued under the Director Plan.

Compensation Committee Interlocks and Insider Participation

We do not currently have a compensation committee or another committee performing similar functions, and all such matters which would be considered by such committee are acted upon by the full Board of Directors of our general partner. Employees of El Paso Corporation, through our general partner, are the individuals who work on our matters. Accordingly, the only compensation we addressed relates to issuance of unit options under our various option plans. The Board of Directors administers and interprets the Omnibus Plan. See Item 11, Executive Compensation.

Audit and Conflicts Committee

Currently, Messrs. Bracy, Church, Smalley and Wallop, who are neither officers nor employees of our general partner nor any of its affiliates, serve as our Audit and Conflicts Committee of the Board of Directors of our general partner. The Audit and Conflicts Committee provides two primary services. First, it advises the Board of Directors in matters regarding the system of internal controls and the annual independent audit, and reviews policies and practices of our general partner and us. Second, the Special Conflicts Committee (consisting of independent directors, namely Messrs. Bracy, Church, and Smalley), 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 Special Conflicts 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.

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 management agreement. Prior to May 2001, our general partner received remuneration for its one percent nonmanaging interest in twelve of our subsidiaries. In May 2001, we acquired the non-managing interest from our general partner.

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, we believe directors, executive officers and greater than 10 percent beneficial owners complied with all filing requirements during the year ended December 31, 2001. In connection with a 1999 restructuring of assets, El Paso Corporation and certain of its subsidiaries, including our general partner, should have filed a Form 5 reporting a change in beneficial ownership of our common units by February 14, 2000. The appropriate form was filed on November 9, 2001.

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.

In August 1998, Mr. Lytal entered into an employment agreement with a five year term with El Paso Corporation, pursuant to which he would continue to serve as our President and president of our general partner. However, pursuant to the terms of his employment agreement, Mr. Lytal has the right to terminate such agreement upon 30 days notice and El Paso Corporation has the right to terminate such agreement under a variety of circumstances.

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 or 2000. At February 8, 2002, 1,097,000 unit options remain unissued under the Omnibus Plan.

Report From Compensation Committee Regarding Executive Compensation

Because we do not have a compensation committee or another committee performing similar functions, this report is presented by the full Board of Directors of our general partner. The Board of Directors is 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 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 the Omnibus Plan described above are implemented and periodically reviewed and adjusted by the Board of Directors. The awards made under the Omnibus Plan are 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.

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, 2001, exceeded $100,000:

		Annual Compensation(1)			Long-Term Compensation	
Name/Principal Position	Fiscal Year	Salary ($)	Bonus ($)	Other Annual Compensation ($)	Awards Unit Options (#)	All Other Compensation ($)
William A. Wise	2001	—	—	—	—	—
Chairman of the Board	2000	—	—	—	—	—
	1999	—	—	—	—	—
Robert G. Phillips	2001	—	—	—	97,500	—
Chief Executive Officer	2000	—	—	—	—	—
	1999	—	—	—	—	—
James H. Lytal	2001	—	—	—	45,000	—
President	2000	—	—	—	—	—
	1999	—	—	—	—	—
D. Mark Leland	2001	—	—	—	60,000	—
Senior Vice President & Controller	2000	—	—	—	—	—
	1999	—	—	—	—	—
Keith B. Forman	2001	—	—	—	15,000	—
Chief Financial Officer	2000	—	—	—	—	—
	1999	—	—	—	—	—

(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

The following table sets forth the number of unit options granted at fair market value to each of the executives named in this Form 10-K during the fiscal year 2001. In accordance with applicable SEC regulations, the table further sets forth the potential realizable value of such unit options in the year 2011 (the expiration date of the unit options) at arbitrarily assumed annualized rates of unit price appreciation of 5 percent and 10 percent over the full ten-year term of the unit options. As the table indicates, the annualized unit price appreciation of 5 percent and 10 percent will result in unit prices in the year 2011 of approximately $56.995 and $90.755. The amounts shown in the table as potential realizable values for all unitholders' units (approximately $874 million and $2.2 billion), represent the corresponding increases in the market value of 39,738,974 common units outstanding as of December 31, 2001. No gain to the executives named in this Form 10-K is possible without an increase in unit price, which would benefit all unitholders proportionately. Actual gains, if any, on unit option exercises and common unit holdings are dependent on the future performance of the common unit and overall unit market conditions. There can be no assurances that the potential realizable values shown in this table will be achieved.

UNIT OPTION GRANTS IN 2001

	Individual Grants(1)				Potential Realizable Value at Assumed Annual Rates of Unit Price Appreciation for Option Term	
Name	Number of Securities Underlying Options Granted(#)	% of Total Unit Options Granted to all Employees in 2001	Exercise Price ($/Unit)	Expiration Date	If Unit Price at $56.995 in 2011 5%($)	If Unit Price at $90.755 in 2011 10%($)
All Unitholder's Unit Appreciation	**N/A**	**N/A**	**N/A**	**N/A**	**$874,457,037**	**$2,216,045,820**
William A. Wise	—	N/A	N/A	N/A	$ —	$ —
Robert G. Phillips	97,500	9.67%	$34.99	9/19/2011	$ 2,145,490	$ 5,437,092
James H. Lytal	45,000	4.46%	$34.99	9/19/2011	$ 990,226	$ 2,509,427
D. Mark Leland	60,000	5.95%	$34.99	9/19/2011	$ 1,320,301	$ 3,345,903
Keith B. Forman	15,000	1.49%	$34.99	9/19/2011	$ 330,075	$ 836,476

(1) The unit options granted in 2001 by us to the executives named in this Form 10-K vest one-half on each of the first two anniversaries of the grant date. There were no unit appreciation rights granted in 2001. Under the terms of the Omnibus Plan, the Plan Administrator, may, in its sole discretion and at any time, change the vesting of the unit options. Unit options are nontransferable and subject to forfeiture and/or time limitations in the event of a termination of employment.

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 2001

AND FISCAL YEAR-END UNIT OPTION VALUES

Name	Units Acquired on Exercise (#)	Value Realized($)[1]	Number of Securities Underlying Unexercised Options at Fiscal Year-End(#)		Value of Unexercised In-the-Money Options at Fiscal Year-End($)[2]	
			Exercisable	Unexercisable	Exercisable	Unexercisable
William A. Wise	—	$ —	—	—	$ —	$ —
Robert G. Phillips	—	$ —	—	97,500	$ —	$183,788
James H. Lytal	—	$ —	215,000	45,000	$2,082,813	$ 84,825
D. Mark Leland	—	$ —	—	60,000	$ —	$113,100
Keith B. Forman	—	$ —	215,000	15,000	$2,082,813	$ 28,275

(1) The figures presented in this column have been calculated based upon the difference between the fair market value of the securities underlying each unit option on the date of exercise and its exercise price.

(2) The figures presented in these columns have been calculated based upon the difference between $36.875, the fair market value of the common units on December 31, 2001, 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, 2001.

ITEM 12. SECURITY OWNERSHIP OF MANAGEMENT

The following table sets forth, as of February 20, 2002, 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)	Unit Options[1]	Total	Percent of Class
Common Units	General Partner/ El Paso Corporation	(2)	—	(2)	(2)
Common Units	Robert G. Phillips	10,000	—	10,000	*
Common Units	James H. Lytal	8,016(3)	215,000	223,016	*
Common Units	Keith B. Forman	2,000	215,000	217,000	*
Common Units	William A. Wise	9,670(4)	—	9,670	*
Common Units	H. Brent Austin	6,000	—	6,000	*
Common Units	D. Mark Leland	2,000	—	2,000	*
Common Units	Michael B. Bracy	6,666	5,500	12,166	*
Common Units	H. Douglas Church	2,712	4,000	6,712	*
Common Units	Kenneth L. Smalley	—	2,500	2,500	*
Common Units	Malcolm Wallop	1,212	5,500	6,712	*
Common Units	Directors and executive officers as a group (10 persons)	48,276	447,500	495,776	1,232

* Less than 1 percent.

(1) The Directors and executive Officers have the right to acquire the shares of common units reflected in this column within 60 days of February 28, 2002, 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 10,430,834 common units, or 26 percent of our outstanding common units, 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) Mr. Wise disclaims beneficial ownership of 2,500 common units held by spouse and 58,701 common units held by daughters.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

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 that 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 Special 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 approve and recommend the proposed transaction.

We will only consummate any proposed transaction with El Paso Corporation if, following its evaluation of the transaction, the Special Conflicts Committee approves and recommends the proposed 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.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this Annual Report or incorporated by reference:

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.

None. All financial statement schedules 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 Report of Independent Accountants
December 31, 2001

Report of Independent Accountants

To the Members of Poseidon Oil Pipeline Company, L.L.C.:

In our opinion, the accompanying balance sheet and the related statements of income, members' capital 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, 2001, and the results of its operations and its cash flows for the year then ended 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 audit. We conducted our audit 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 audit provides a reasonable basis for our opinion. The financial statements of the Company as of December 31, 2000 and for the two years in the period ended December 31, 2000 were audited by other independent accountants whose report dated March 16, 2001 expressed an unqualified opinion on those statements.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 28, 2002

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

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF INCOME

(In thousands)

	For the Years Ended December 31,		
	2001	2000	1999
Operating revenues			
Transportation and crude oil sales	$1,196,840	$1,466,086	$1,108,124
Operating expenses			
Crude oil purchases	1,125,324	1,400,928	1,034,330
Transportation costs	1,115	1,793	3,452
Operation and maintenance	1,586	4,487	4,188
Repair expenses	—	18,118	—
Depreciation and amortization	10,552	10,754	6,172
	1,138,577	1,436,080	1,048,142
Operating income	58,263	30,006	59,982
Other income (expense)			
Interest income	394	639	404
Interest and debt expense	(7,668)	(11,683)	(9,133)
Net income	$ 50,989	$ 18,962	$ 51,253

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

BALANCE SHEETS

As of December 31, 2001 and 2000
(In thousands)

	2001	2000
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,095	$ 2,532
Accounts receivable, trade	51,497	66,917
Accounts receivable, affiliate	36,563	53,291
Other current assets	2,212	2,585
Total current assets	91,367	125,325
Property, plant and equipment, net	222,363	232,791
Debt reserve fund	3,499	6,239
Other noncurrent assets	708	—
Total assets	$317,937	$364,355
LIABILITIES AND MEMBERS’ CAPITAL		
Current liabilities		
Accounts payable, trade	$ 43,574	$ 62,494
Accounts payable, affiliate	36,791	52,282
Current maturities of revolving credit facility	—	150,000
Total current liabilities	80,365	264,776
Revolving credit facility	150,000	—
Reserve for revenue refund	—	1,297
Commitments and contingencies		
Members’ capital	87,572	98,282
Total liabilities and members’ capital	$317,937	$364,355

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF CASH FLOWS

(In thousands)

	For the Years Ended December 31,		
	2001	2000	1999
Cash flows from operating activities			
Net income	$ 50,989	$ 18,962	$ 51,253
Adjustments to reconcile net income to cash provided by operating activities			
Depreciation and amortization	10,552	10,754	6,172
Changes in operating assets and liabilities			
Decrease (increase) in accounts receivable	32,148	48,828	(128,640)
Decrease (increase) in other current assets	373	(2,993)	395
(Decrease) increase in accounts payable	(34,411)	(44,491)	119,731
(Decrease) increase in reserve for revenue refund	(1,297)	975	322
Decrease in other current liabilities	—	(93)	(505)
Net cash provided by operating activities	58,354	31,942	48,728
Cash flows from investing activities			
Capital expenditures	(124)	(3,323)	(16,606)
Construction advances to operator, net	—	4	1,230
Net cash used in investing activities	(124)	(3,319)	(15,376)
Cash flows from financing activities			
Proceeds from issuance of debt	—	—	20,000
Repayments of long-term debt	—	—	(1,000)
Debt issue costs	(708)	—	—
Cash contributions	—	10,900	—
Distributions to partners	(61,699)	(37,588)	(50,531)
Decrease (increase) in debt reserve fund	2,740	(1,456)	(454)
Net cash used in financing activities	(59,667)	(28,144)	(31,985)
Increase (decrease) in cash and cash equivalents	(1,437)	479	1,367
Cash and cash equivalents:			
Beginning of period	2,532	2,053	686
End of period	$ 1,095	$ 2,532	$ 2,053
Supplemental disclosure of cash flow information			
Cash paid for interest, net of amounts capitalized	$ 6,423	$ 11,683	$ 8,730

See accompanying notes.

POSEIDON OIL PIPELINE COMPANY, L.L.C.

STATEMENTS OF MEMBERS' CAPITAL

For the Years Ended December 31, 2001, 2000 and 1999
(In thousands)

	Equilon Enterprises, L.L.C. (36%)	Poseidon Pipeline Company, L.L.C. (36%)	Marathon Oil Company (28%)	Total
Balance at December 31, 1998	$ 37,903	$ 37,903	$ 29,480	$105,286
Cash distributions	(18,191)	(18,191)	(14,149)	(50,531)
Net income	18,451	18,451	14,351	51,253
Balance at December 31, 1999	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

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 current members are Equilon Enterprises, L.L.C. (Equilon), Poseidon Pipeline Company, L.L.C. (Poseidon), a subsidiary of El Paso Energy Partners, L.P., and Marathon Pipeline Company (MPLC), which own 36 percent, 36 percent, and 28 percent in us.

Equilon 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 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, 2001 and 2000, the balance in the account was approximately \$3.5 million and \$6.2 million, and consisted of funds earning interest at 1.7% and 6.1%.

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, 2001 and 2000, 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.

Asset Impairment

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

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.

Fair Value of Financial Instruments

The estimated fair values of all financial instruments approximate their carrying amounts in the accompanying balance sheet due to the short-term maturity of these instruments.

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.

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.

Environmental Costs

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

Accounting for Price Risk Management Activities

We have adopted SFAS No. 133 beginning January 1, 2001, which requires us to measure all derivative instruments at their fair value, and classify them as either assets or liabilities on our balance sheet, with 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. We have determined that there is no impact on us as of December 31, 2001.

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 includable 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.

Cash Distributions

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. Our income is allocated to our members based on their ownership percentages.

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.

Recent Pronouncements

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

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

Note 2 — Property, Plant and Equipment

Our property, plant and equipment consisted of the following:

	December 31,	
	2001	2000
	(In thousands)	
Pipeline and equipment, at cost	$266,614	$266,614
Construction work in progress	706	582
	267,320	267,196
Less accumulated depreciation	(44,957)	(34,405)
Total property, plant and equipment, net	$222,363	$232,791

During 2001 and 2000, 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. This facility is collateralized by a substantial portion of our assets and matures in April 2004. As of December 31, 2001, we had $150 million outstanding under this facility with the full unused amount available. The average variable floating interest rate was 3.9% and 7.9% at December 31, 2001 and 2000. 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.

In January 2002, we entered into a two-year interest rate swap to fix the interest rate on $75 million of our variable rate revolving credit facility at 3.49 percent through January 2004. This swap will be accounted for in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, beginning in the first quarter 2002.

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,		
	2001	2000	1999
	% of total revenues	% of total revenues	% of total revenues
Marathon Oil Company	20%	17%	31%
Amerada Hess Company	16%	19%	12%
Equiva Trading Company	15%	16%	12%
Texon L.P.	10%	12%	—
Anadarko	10%	—	—
British-Borneo USA, Inc.	—	11%	—

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 $489 million in gross affiliated sales and approximately $489 in gross affiliated purchases for 2001. During 2000 and 1999, we generated approximately $30 million and $41 million of net margin from related parties. The decline in margin for 2001 is due to us purchasing more oil from our related parties than we actually sold to our related parties. The excess purchases were sold to third party customers.

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 2001. Prior to Manta Ray Gathering Company, L.L.C., taking over as operator, Equilon received approximately $1.1 million and $1.2 million in 2000 and 1999, respectively, for management, administrative and general overhead. During 2000, we paid Equilon an additional management fee of approximately $1.7 million associated with the repair of our ruptured pipeline.

Note 6 — Commitments and Contingencies

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.

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.

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. Based on barrels delivered through December 31, 2001 and our estimates through September 2003, we believe Pennzoil will 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 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. We have filed a lawsuit against Transocean for damages to the pipeline. The outcome of this litigation is still pending.

EL PASO ENERGY PARTNERS, L.P.

EXHIBIT LIST

December 31, 2001

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 14(c) of Form 10-K.

Exhibit Number	Description
*3.A	— Amended and Restated Certificate of Limited Partnership dated February 14, 2002.
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).
4.A	— A/B Exchange Registration Rights Agreement dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors, Donaldson, Lufkin & Jenrette Securities Corporation, and Chase Securities Inc. (Exhibit 4.7 to our Registration Statement on Form S-4, filed on June 21, 1999, File Nos. 333-81143 through 333-81143-17).
4.B	— A/B Exchange Registration Rights Agreement dated as of May 17, 2001 between El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors listed on Schedule A thereto, Credit Suisse First Boston Corporation, Goldman, Sachs & Co., and J.P. Morgan Securities Inc. (Exhibit 4.3 to our Registration Statement on Form S-4, filed on June 25, 2001, Registration Nos. 333-63800 through 333-63800-20).
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).
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).
*4.F	— Letter agreement dated March 5, 2002, between Crystal Gas Storage, Inc. and El Paso Energy Partners, LP.

Exhibit Number	Description
10.A	— First Amended and Restated Management Agreement, dated June 27, 1994 and effective as of July 1, 1992, between DeepTech International Inc. and the General Partner (Exhibit 10.1 to DeepTech's 1994 Form 10-K); First Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.76 to DeepTech's Registration Statement on Form S-1, filed on January 23, 1995, File No. 33-88688); Second Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.18 to our 1995 Form 10-K); Third Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.4 to our Registration Statement on Form S-4, filed on June 21, 1999, File No. 333-81143); Fourth Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.1 to our 1997 Second Quarter Form 10-Q); Fifth Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.1 our 1997 Third Quarter Form 10-Q); Sixth Amendment to First Amended and Restated Management Agreement between DeepTech International Inc. and the General Partner (Exhibit 10.2 to our 1998 Form 10-K).
10.B	— Fifth Amended and Restated Credit Agreement dated as of March 23, 1995, as amended and restated through May 16, 2001 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 10.2 to our 2001 Third Quarter Form 10-Q); First Amendment to Fifth Amended and Restated Credit Agreement dated as of October 10, 2001 (Exhibit 10.2.1 to our 2001 Third Quarter Form 10-Q).
10.C	— Credit Agreement dated as of August 23, 2000 by and among Argo, L.L.C., the lenders party thereto, the Chase Manhattan Bank, as administrative agent, First Union National Bank, as syndication agent, Bank One, N.A., as documentation agent, and Chase Securities Inc., as arranger (Exhibit 10.14 to our 2000 Third Quarter Form 10-Q).
10.D	— Sponsor Agreement dated as of August 23, 2000, by El Paso Energy Partners, L.P., and the Chase Manhattan Bank, as administrative agent (Exhibit 10.15 to our 2000 Third Quarter Form 10-Q).
10.E	— Redemption Agreement dated February 27, 1998 between Tatham Offshore, Inc. and Flextrend Development Company, L.L.C., a subsidiary of El Paso Energy Partners, L.P. (Exhibit 10.1 our 1998 Third Quarter Form 10-Q).
10.F	— Farmout Agreement dated October 25, 1999 by and between Flextrend Development Company, L.L.C. and El Paso Production GOM, Inc. (Exhibit 10.15 to our Report on Form 8-K, filed on November 15, 1999).
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. (Exhibit 10.14 to our 2000 Second Quarter Form 10-Q).
10.H	— Fabrication Agreement dated as of July 16, 1999 by and between Delos Offshore Company and MODEC International LLC; Amendment No. 1 to the Fabrication Agreement dated as of August 31, 1999 by and between Delos Offshore Company and MODEC International LLC. (Exhibit 10.20 to our 2000 Second Quarter Form 10-Q).

Exhibit Number	Description
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.J	— Assignment, Acceptance and Amendment dated October 4, 2001 by and between Delos Offshore Company, L.L.C., a Delaware limited liability company, The Chase Manhattan Bank, KBC Bank N.V., The Sumitomo Bank, Limited, Royal Bank of Canada, The Bank of New York, Societe Generale, Southwest Agency, Societe Generale Financial Corporation, The Industrial Bank of Japan, Limited New York Branch, El Paso New Chaco Company, L.L.C., El Paso Natural Gas Company, El Paso Corporation, The Chase Manhattan Bank, in its capacity as Agent, and the State Street Bank and Trust Company, not in its individual capacity but solely as trustee for the Chaco Liquids Plant Trust (Exhibit 2.2 to our Report on Form 8-K dated October 25, 2001).
10.K	— Tolling Agreement dated as of October 1, 2001 between El Paso Field Services, L.P., and Delos Offshore Company, L.L.C. (Exhibit 2.3 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 our 2000 Second Quarter Form 10-Q).
*21.	— Subsidiaries of El Paso Energy Partners, L.P.
*23.A	— Consent of Independent Accountants.
*23.B	— Consent of Independent Petroleum Engineers.

(b) Reports on Form 8-K

- We filed a current report on Form 8-K dated October 4, 2001, announcing that we had entered into a series of transactions to acquire midstream assets for $284 million and would raise the annual distribution to $2.45 per common unit.

- We filed a current report on Form 8-K dated October 19, 2001, in order (a) to include in our current risk factors a discussion of the potential effect of regulations proposed by the Federal Energy Regulatory Commission, or FERC, as well as risks associated with our newly-acquired Chaco cryogenic natural gas processing plant and (b) to disclose our authorization of the issuance of unit options.

- We filed a current report on Form 8-K dated October 19, 2001, providing unaudited pro forma condensed consolidated and combined financials for our acquisition of the remaining 50 percent interest in Deepwater Holdings, L.L.C., and our acquisition of the Chaco cryogenic natural gas processing plant; our acquisition of the Crystal natural gas storage business and the natural gas liquids transportation and fractionation assets; our sale of several Gulf of Mexico assets; and our issuance of 5,627,070 common units, which includes 1,477,070 common units to be purchased by our general partner.

- We filed a current report on Form 8-K dated October 25, 2001, to announce our acquisition of (a) title to and other interests in the Chaco cryogenic natural gas processing plant in northern New Mexico’s San Juan Basin and (b) the remaining 50 percent indirect interest that we did not already own in Deepwater Holdings, L.L.C., through which the High Island Offshore System and East Breaks natural gas gathering system became indirectly wholly-owned assets.

- We filed a current report on Form 8-K dated October 25, 2001, to file consents from experts with respect to reports incorporated by reference into our Registration Statement on Form S-3 (File No. 333-85987).

- We filed a current report on Form 8-K dated October 30, 2001, to announce that we entered into an Underwriting Agreement with our General Partner and the underwriters named therein in connection with our public offering of up to 4,772,500 common units representing limited partner interests.

- We filed a current report on Form 8-K/A dated November 8, 2001, providing unaudited proforma financial statements for our acquisition of the remaining 50 percent interest in Deepwater Holdings, L.L.C., and our acquisition of title to and other interests in the Chaco cryogenic natural gas processing plant; our acquisition of the Crystal natural gas storage business and the natural gas liquids transportation and fractionation assets; and our sale of several Gulf of Mexico assets. We also provided unaudited Deepwater Holdings, L.L.C. financial statements as of and for the periods ended June 30, 2001 and 2000.

- We filed a current report on Form 8-K dated December 14, 2001, announcing our 2001 earnings expectations and the anticipated acquisition of additional midstream businesses from El Paso Corporation, including the EPGT Texas Pipeline, in early 2002.

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 seventh day of March 2002.

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/ WILLIAM A. WISE William A. Wise	Chairman of the Board and Director	March 7, 2002
/s/ ROBERT G. PHILLIPS Robert G. Phillips	Chief Executive Officer and Director	March 7, 2002
/s/ JAMES H. LYTAL James H. Lytal	President and Director	March 7, 2002
/s/ KEITH B. FORMAN Keith B. Forman	Chief Financial Officer and Vice President	March 7, 2002
/s/ D. MARK LELAND D. Mark Leland	Senior Vice President and Controller (Principal Accounting Officer)	March 7, 2002
/s/ H. BRENT AUSTIN H. Brent Austin	Executive Vice President and Director	March 7, 2002
/s/ MICHAEL B. BRACY Michael B. Bracy	Director	March 7, 2002
/s/ H. DOUGLAS CHURCH H. Douglas Church	Director	March 7, 2002
/s/ KENNETH L. SMALLEY Kenneth L. Smalley	Director	March 7, 2002
/s/ MALCOLM WALLOP Malcolm Wallop	Director	March 7, 2002

EL PASO ENERGY PARTNERS, L.P.

INDEX TO EXHIBITS

December 31, 2001

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 14(c) of Form 10-K.

Exhibit Number	Description
*3.A	— Amended and Restated Certificate of Limited Partnership dated February 14, 2002.
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).
4.A	— A/B Exchange Registration Rights Agreement dated as of May 27, 1999 among El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors, Donaldson, Lufkin & Jenrette Securities Corporation, and Chase Securities Inc. (Exhibit 4.7 to our Registration Statement on Form S-4, filed on June 21, 1999, File Nos. 333-81143 through 333-81143-17).
4.B	— A/B Exchange Registration Rights Agreement dated as of May 17, 2001 between El Paso Energy Partners, L.P., El Paso Energy Partners Finance Corporation, the Subsidiary Guarantors listed on Schedule A thereto, Credit Suisse First Boston Corporation, Goldman, Sachs & Co., and J.P. Morgan Securities Inc. (Exhibit 4.3 to our Registration Statement on Form S-4, filed on June 25, 2001, Registration Nos. 333-63800 through 333-63800-20).
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).
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).
*4.F	— Letter agreement dated March 5, 2002, between Crystal Gas Storage, Inc. and El Paso Energy Partners, LP.

Exhibit Number	Description
10.A	— First Amended and Restated Management Agreement, dated June 27, 1994 and effective as of July 1, 1992, between DeepTech International Inc. and the General Partner (Exhibit 10.1 to DeepTech's 1994 Form 10-K); First Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.76 to DeepTech's Registration Statement on Form S-1, filed on January 23, 1995, File No. 33-88688); Second Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.18 to our 1995 Form 10-K); Third Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.4 to our Registration Statement on Form S-4, filed on June 21, 1999, File No. 333-81143); Fourth Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.1 to our 1997 Second Quarter Form 10-Q); Fifth Amendment to First Amended and Restated Management Agreement between DeepTech and General Partner (Exhibit 10.1 our 1997 Third Quarter Form 10-Q); Sixth Amendment to First Amended and Restated Management Agreement between DeepTech International Inc. and the General Partner (Exhibit 10.2 to our 1998 Form 10-K).
10.B	— Fifth Amended and Restated Credit Agreement dated as of March 23, 1995, as amended and restated through May 16, 2001 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 10.2 to our 2001 Third Quarter Form 10-Q); First Amendment to Fifth Amended and Restated Credit Agreement dated as of October 10, 2001 (Exhibit 10.2.1 to our 2001 Third Quarter Form 10-Q).
10.C	— Credit Agreement dated as of August 23, 2000 by and among Argo, L.L.C., the lenders party thereto, the Chase Manhattan Bank, as administrative agent, First Union National Bank, as syndication agent, Bank One, N.A., as documentation agent, and Chase Securities Inc., as arranger (Exhibit 10.14 to our 2000 Third Quarter Form 10-Q).
10.D	— Sponsor Agreement dated as of August 23, 2000, by El Paso Energy Partners, L.P., and the Chase Manhattan Bank, as administrative agent (Exhibit 10.15 to our 2000 Third Quarter Form 10-Q).
10.E	— Redemption Agreement dated February 27, 1998 between Tatham Offshore, Inc. and Flextrend Development Company, L.L.C., a subsidiary of El Paso Energy Partners, L.P. (Exhibit 10.1 our 1998 Third Quarter Form 10-Q).
10.F	— Farmout Agreement dated October 25, 1999 by and between Flextrend Development Company, L.L.C. and El Paso Production GOM, Inc. (Exhibit 10.15 to our Report on Form 8-K, filed on November 15, 1999).
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. (Exhibit 10.14 to our 2000 Second Quarter Form 10-Q).
10.H	— Fabrication Agreement dated as of July 16, 1999 by and between Delos Offshore Company and MODEC International LLC; Amendment No. 1 to the Fabrication Agreement dated as of August 31, 1999 by and between Delos Offshore Company and MODEC International LLC. (Exhibit 10.20 to our 2000 Second Quarter Form 10-Q).

Exhibit Number	Description
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.J	— Assignment, Acceptance and Amendment dated October 4, 2001 by and between Delos Offshore Company, L.L.C., a Delaware limited liability company, The Chase Manhattan Bank, KBC Bank N.V., The Sumitomo Bank, Limited, Royal Bank of Canada, The Bank of New York, Societe Generale, Southwest Agency, Societe Generale Financial Corporation, The Industrial Bank of Japan, Limited New York Branch, El Paso New Chaco Company, L.L.C., El Paso Natural Gas Company, El Paso Corporation, The Chase Manhattan Bank, in its capacity as Agent, and the State Street Bank and Trust Company, not in its individual capacity but solely as trustee for the Chaco Liquids Plant Trust (Exhibit 2.2 to our Report on Form 8-K dated October 25, 2001).
10.K	— Tolling Agreement dated as of October 1, 2001 between El Paso Field Services, L.P., and Delos Offshore Company, L.L.C. (Exhibit 2.3 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 our 2000 Second Quarter Form 10-Q).
*21.	— Subsidiaries of El Paso Energy Partners, L.P.
*23.A	— Consent of Independent Accountants.
*23.B	— Consent of Independent Petroleum Engineers.

EXHIBIT 3.A

AMENDED AND RESTATED CERTIFICATE OF LIMITED PARTNERSHIP OF EL PASO ENERGY PARTNERS, L.P.

The undersigned, desiring to Amended and Restate the Certificate of Limited Partnership of El Paso Energy Partners, L.P., pursuant to the provisions of Sections 17-202 and 17-210 of the Delaware Revised Uniform Limited Partnership Act, as amended ("DRULPA") does hereby certify as follows:

1. The original Certificate of Limited Partnership was filed with the Office of the Secretary of State of Delaware on December 4, 1992 under the name of Leviathan Gas Pipeline Partners, L.P.

2. The Certificate of Limited Partnership was Amended on December 1, 1999, changing the name of the Limited Partnership to El Paso Energy Partners, L.P.

3. The Certificate of Limited Partnership was Amended on January 14, 2002 changing the name of the General Partner and Registered Agent.

4. This Amended and Restated Certificate of Limited Partnership has been adopted and approved by the General Partner in accordance with Section 17-202 of the Delaware Revised Uniform Limited Partnership Act, pursuant to which, this Amended and Restated Certificate of Limited Partnership amends and restates the provisions of the Limited Partnership's Certificate of Limited Partnership.

5. The text of the Certificate of Limited Partnership of the Limited Partnership is hereby amended and restated to read in its entirety as follows:

ARTICLE I
NAME

The name of the Limited Partnership shall be El Paso Energy Partners, L.P. (hereinafter, the "Company")

ARTICLE II
POWER

The Company shall have all the powers accorded to a limited partnership organized under the DRULPA.

ARTICLE III
PURPOSE

The purpose for which the company is organized is to transact any and all lawful business for which a limited partnership may be organized under the DRULPA.

ARTICLE IV
GENERAL PARTNER

The name and mailing address of each party who is to serve as the general partner is as follows:

El Paso Energy Partners Company
1001 Louisiana Street
Houston, Texas 77002

ARTICLE V
PARTNERSHIP AGREEMENT

The general partner shall adopt the Partnership Agreement (the "Agreement") that shall govern the operations of the Company; provided, however, that the failure to adopt such Agreement prior to the date on which this Certificate of Limited Partnership ("Certificate") is filed with the Secretary of State of the State of Delaware shall not affect the Company's commencement of existence on such date. The Agreement shall provide for all the terms and conditions for the governance of the Company not inconsistent with any rule of law or equity or with this Certificate and may be altered, amended, restated, or repealed by the Company in the manner set forth therein.

ARTICLE VI
INDEMNIFICATION

Subject to such standards and restrictions as are set forth in the Agreement, the Company shall have the power and authority to indemnify and hold harmless any general partner, limited partner, officer, director, or any other person against any and all claims and demands whatsoever to the fullest extent permitted by law.

ARTICLE VII
REGISTERED OFFICE
AND REGISTERED AGENT

The registered office of the Company is 1209 Orange Street, Wilmington, Delaware 19801, and the registered agent of the Company at such address is The Corporation Trust Company.

IN WITNESS WHEREOF, the undersigned has executed this Amended and Restated Certificate of Limited Partnership on this 12th day of February 2002.

EL PASO ENERGY PARTNERS COMPANY

By: /s/ DAVID L. SIDDALL

David L. Siddall
Vice President

EL PASO ENERGY PARTNERS, L.P.
El Paso Energy Building
1001 Louisiana
Houston, Texas 77002

March 5, 2002

Jeffrey A. Ballew
Executive Vice President
Crystal Gas Storage, Inc.
1001 Louisiana Street
Houston, Texas 77002

Re: Letter agreement regarding distributions on the Series B Preference Units (the "Preference Units") issued by El Paso Energy Partners, L.P. ("El Paso Partners") to Crystal Gas Storage, Inc. ("Crystal")

Dear Jeff:

In connection with El Paso Partners' acquisition of Petal and Hattiesburg gas storage businesses from Crystal, we entered into an Agreement and Plan of Merger dated August 28, 2000 (the "Merger Agreement") and various other transaction documents and El Paso Partners issued to you 170,000 Preference Units, with specific rights, privileges and preferences. This letter agreement (i) acknowledges and confirms our original intent regarding the priority the Preference Units should have over other units with respect to certain distributions and (ii) to the extent there are any transaction documents or other documents or instruments containing an ambiguity, inconsistency or mistake with respect thereto, modifies the agreements embodied in such documents to the extent necessary to conform them to our original intent.

We both acknowledge and agree that the following evidences our original and current agreement:

> The Preference Units are senior to all other units regarding rights to certain distributions. In particular, commencing with distributions paid after December 31, 2010, El Paso Partners may not

make distributions on its common units or any other units if El Paso Partners is in arrears with respect to any accretions on the Preference Units that relate to any calendar quarter after the third quarter of 2010. Stated more technically, with respect to the calendar quarter commencing on October 1, 2010 and each calendar quarter thereafter, El Paso Partners may not make distributions of available cash on its common units or any other units unless El Paso Partners has made aggregate distributions of available cash on the Preference Units with respect to the period commencing on October 1, 2010 in an amount at least equal to the aggregate accretions on the Preference Units with respect to the same period. El Paso Partners will not be prohibited from making distributions on its common units or other units merely because El Paso Partners has not made distributions on the Preference Units with respect to all accretions relating to the period commencing on the Preference Unit issuance date and ending on September 30, 2010.

Crystal confirms, acknowledges and agrees that, to the extent any agreement, document or other instrument grants or purports to grant Crystal any rights with respect to distributions on the Preference Units that are inconsistent with the rights expressed in the immediately preceding paragraph:

1. Crystal hereby waives, relinquishes and forfeits any such right forever;

2. Crystal is the sole holder of the Preference Units and has not (directly or indirectly) sold, assigned, transferred or otherwise alienated any of its rights or interest in any of the outstanding Preference Units, other than transfers to wholly-owned subsidiaries of El Paso Corporation; and

3. Crystal agrees to cooperate and work diligently, exercising commercially reasonable efforts, to take (or to cause to be taken) all actions and to do (or to cause to be done) all things necessary, proper or advisable (now or in the future) under applicable laws to consummate and make effective the transactions contemplated by this letter agreement, including making appropriate annotations on all certificates, if any, evidencing the existence of the Preference Units.

This letter agreement (i) shall be binding upon and shall inure to the benefit of the parties hereto and their respective successors and assigns, (ii) shall be subject to any and all governmental rules, regulations and laws (whether now existing or hereafter arising) which are applicable to the parties hereto, (iii) may be executed in multiple counterparts, each of which shall constitute but one and the same instrument, (iv) contains all necessary terms and conditions for the agreements described herein to be binding upon the parties hereto, and the parties agree to be bound by the terms and conditions of this letter agreement, (v) shall be valid in all jurisdictions except to the extent any term or provision of this letter agreement is invalid or unenforceable in any jurisdiction; provided, however, any such term or provision that is invalid or unenforceable in any jurisdiction shall be ineffective as to such jurisdiction, to the extent of such invalidity or unenforceability, without rendering invalid or unenforceable the remaining terms and provisions of this letter agreement or affecting the validity or enforceability of any terms and provisions of this letter agreement in any other jurisdiction, and (vi) SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS WITHOUT REGARD TO ANY CONFLICT OR CHOICE OF LAW PRINCIPLES WHICH, IF APPLIED, MIGHT PERMIT OR REQUIRE THE APPLICATION OF THE LAW OF ANOTHER JURISDICTION, EXCEPT TO THE EXTENT THAT THE INTERNAL LAWS OF THE STATE OF DELAWARE ARE REQUIRED TO BE APPLIED.

****

If the foregoing accurately represents your understanding of the agreement of the parties hereto, please so indicate by signing this letter agreement in the appropriate space provided below and returning one fully executed copy to me.

Sincerely,

EL PASO ENERGY PARTNERS, L.P.

/s/ D. MARK LELAND

D. Mark Leland
Senior Vice President

AGREED TO AND ACCEPTED AS OF
THE DATE OF THIS AGREEMENT:

CRYSTAL GAS STORAGE, INC.

By: /s/ JEFFREY A. BALLEW

Printed Name: Jeffrey A. Ballew
Title: Executive Vice President

[Signature Page of El Paso Partners/Crystal Letter Agreement Regarding Series B Preference Units]

EXHIBIT 21

OWNERSHIP LIST OF EL PASO ENERGY PARTNERS, L.P.
AS OF DECEMBER 31, 2001

% OF ENTITY NAME OWNER OWNERSHIP - ------- ---- ----- --------- Argo I, L.L.C. (DE)......................... Argo II, L.L.C. 100 Argo II, L.L.C. (DE)........................ El Paso Energy Partners, L.P. 100 Argo, L.L.C. (DE)........................... Argo I, L.L.C. 100 Atlantis Offshore, LLC (DE).................. Manta Ray Gathering Company, L.L.C. 50 DeepTech International Inc. (DE)............. El Paso Corporation 100 Delos Offshore Company, L.L.C. (DE) El Paso Energy Partners, L.P. 100 East Breaks Gathering Company L.L.C. (DE).... El Paso Energy Partners Deepwater, L.L.C. 100 El Paso Energy Partners Company (DE)......... DeepTech International Inc. 100 El Paso Energy Partners Deepwater, L.L.C. (DE)...................................... El Paso Energy Partners, L.P. 100 El Paso Energy Partners Finance Corporation (DE)...................................... El Paso Energy Partners, L.P. 100 El Paso Energy Partners Oil Transport, L.L.C. (DE)...................................... El Paso Energy Partners, L.P. 100 El Paso Energy Partners Operating Company, L.L.C. (DE).............................. El Paso Energy Partners, L.P. 100 Flextrend Development Company, L.L.C. (DE)... El Paso Energy Partners, L.P., 100 Green Canyon Pipe Line Company, L.P. (DE).... El Paso Energy Partners, L.P. 97.99(LP) El Paso Energy Partners Oil Transport, L.L.C. 1.00(GP) El Paso Energy Partners Company 1.01 High Island Offshore System, L.L.C. (DE)..... El Paso Energy Partners Deepwater, L.L.C. 100 Manta Ray Gathering Company, L.L.C. (DE)..... El Paso Energy Partners, L.P. 100 Poseidon Oil Pipeline Company, L.L.C. (DE)... Poseidon Pipeline Company, L.L.C. 36 Poseidon Pipeline Company, L.L.C. (DE)....... El Paso Energy Partners, L.P. 100 VK Deepwater Gathering Company, L.L.C. (DE)...................................... El Paso Energy Partners, L.P. 100 VK-Main Pass Gathering Company, L.L.C. (DE)...................................... El Paso Energy Partners, L.P. 100 Crystal Holding, L.L.C. (DE)................. El Paso Energy Partners, L.P. 100 Petal Gas Storage, L.L.C. (DE).............. Crystal Holding, L.L.C. 100 First Reserve Gas, L.L.C. (DE).............. Crystal Holding, L.L.C. 100 EPN NGL Storage, L.L.C. (DE)................ Crystal Holding, L.L.C. 100 Hattiesburg Industrial Gas Sales, L.L.C. (DE)...................................... First Reserve Gas, L.L.C. 100 Hattiesburg Gas Storage Company (DE)........ First Reserve Gas, L.L.C. 50 Hattiesburg Industrial Gas Sales, L.L.C. 50

Exhibit 23.A

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 February 28, 2002 relating to the consolidated financial statements of the Partnership and subsidiaries and (ii) our report dated February 28, 2002 relating to the financial statements of Poseidon Oil Pipeline Company L.L.C., which appear in this Form 10-K.

PRICEWATERHOUSECOOPERS, L.L.P.

Houston, Texas
March 4, 2002

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, 2001, 2000 and 1999, 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, 2001. We also consent to the reference to us under the heading of "Experts" in such Annual Report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ FREDERIC D. SEWELL

Frederic D. Sewell
Chairman, CEO

Dallas, Texas
March 1, 2002