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

FORM 10-K

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

For the fiscal year ended December 31, 2003

OR

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

For the transition period from _________ to_________

Commission File No. 1-11680

GULFTERRA ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

Registrant's telephone number, including area code: (832) 676-4853

Internet Website: www.gulfterra.com

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common units representing limited partner interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

The registrant had 59,623,667 common units outstanding as of March 10, 2004. The aggregate market value on March 10, 2004 and June 30, 2003 of the registrant's common units held by non-affiliates was approximately $2,450 million and $1,869 million.

Documents Incorporated by Reference: None

GULFTERRA ENERGY PARTNERS, L.P.

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PART I

ITEM 1. BUSINESS

General

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

- offshore oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure in the Gulf of Mexico, primarily offshore Louisiana and Texas;
- onshore natural gas pipelines and processing facilities in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas;
- onshore NGL pipelines and fractionation facilities in Texas; and
- onshore natural gas and NGL storage facilities in Louisiana, Mississippi and Texas.

We are one of the largest natural gas gatherers, based on miles of pipeline, in the prolific natural gas supply regions offshore in the Gulf of Mexico and onshore in Texas and New Mexico. These regions, especially the deeper water regions of the Gulf of Mexico, one of the United States' fastest growing oil and natural gas producing regions, offer us significant infrastructure growth potential through the acquisition and construction of pipelines, platforms, processing and storage facilities and other infrastructure.

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

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

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

Our objective is to operate as a growth-oriented MLP with a focus on increasing our cash flow, earnings and return to our unitholders by becoming one of the industry's leading providers of midstream energy services. Our strategy is to maintain and grow a diversified, balanced base of strategically located and efficiently operated midstream energy assets with stable and long-term cash flows. Our strategy contemplates substantial growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets, while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively, diversify our asset portfolio and, thereby, provide more stable cash flow. We own or have interests in:

- over 15,500 miles of natural gas gathering and transportation pipelines with capacity of over 10.9 Bcf/d;
- over 340 miles of offshore oil pipelines with capacity of 635 MBbls/d;
- over 1,000 miles of NGL pipelines with varying capacity of up to 160 MBbls/d;
- five natural gas processing/treating plants with capacity of over 1.5 Bcf/d of natural gas and 50 MBbls/d of NGL;
- four NGL fractionating plants with capacity of 120 MBbls/d of NGL;
- five NGL storage facilities with aggregate capacity of over 25 MMBbls;
- three natural gas storage facilities with aggregate working gas capacity of approximately 20 Bcf; and
- seven offshore hub platforms.

In addition, we currently have midstream projects underway in the Gulf of Mexico with gross estimated capital costs of approximately $862 million, including 426 miles of oil pipelines and 151 miles of natural gas pipelines.

To further our business strategy, we executed definitive agreements with Enterprise Products Partners L.P. (Enterprise) and El Paso Corporation, on December 15, 2003, to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs with an enterprise value of approximately $13 billion as of December 15, 2003.

For further discussion of the merger and related transactions, see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

Segments

We have segregated our business activities into four distinct operating segments:

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

These segments are strategic business units that provide a variety of energy related services. For information relating to revenues from external customers, operating income and total assets of each segment, see Item 8, Financial Statements and Supplementary Data, Note 15. Each of these segments is discussed more fully below.

Natural Gas Pipelines and Plants

Natural Gas Pipelines Systems

We own interests in natural gas pipeline systems extending over 15,500 miles, with a combined maximum design capacity (net to our interest) of over 10.9 Bcf/d of natural gas. We own or have interests in gathering systems onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, including the San Juan gathering system in New Mexico and the Texas Intrastate system. In addition to our onshore natural gas pipeline systems, our offshore natural gas pipeline systems are strategically located to serve production activities in some of the most active drilling and development regions in the Gulf of Mexico, including select locations offshore of Texas, Louisiana and Mississippi, and to provide relatively low cost access to long-line transmission pipelines that access multiple markets in the eastern half of the United States.

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

	San Juan(1)	Permian(2) Basin	Texas Intrastate(2)(3)	GulfTerra Alabama Intrastate(3)	Viosca Knoll(4)	HIOS(3)(5)	East Breaks(5)	Falcon(6)	Typhoon(1)
In-service date	Various	Various	Various	1972	1994	1977	2000	2003	2001
Approximate capacity(7)	1,100	470	4,975	200	1,160	1,800	400	400	400
Aggregate miles of pipeline	5,300	1,064	8,222	450	162	204	85	14	35
Average throughput for the years ended:(8)									
December 31, 2003	1,227	320	3,331	151	670	708	186	177	50
December 31, 2002	1,244	335	3,362	175	565	740	203	N/A	62
December 31, 2001	1,196	344	3,478	171	551	979	245	N/A	51

(1) The average throughput reflects 100 percent of the throughput. We acquired the San Juan gathering system and the Typhoon natural gas pipeline in November 2002. The Typhoon natural gas pipeline was placed in service in August 2001.

(2) The average throughput reflects 100 percent of the throughput. We acquired the Texas Intrastate system and the Permian Basin system in April 2002.

(3) The Texas Intrastate system is comprised of the GulfTerra Texas Intrastate, the TPC Offshore and the Channel pipeline systems. The Railroad Commission of Texas regulates the rates of the GulfTerra Texas and Channel systems. The Federal Energy Regulatory Commission (FERC) regulates the Section 311 rates of the GulfTerra Texas system, the Channel system and GulfTerra Alabama Intrastate. HIOS is also regulated by the FERC as an interstate pipeline under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978.

(4) In the fourth quarter of 2003, we completed the 37-mile Medusa extension of our Viosca Knoll gathering system.

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

(6) The Falcon gas pipeline went into service in March 2003.

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

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

San Juan Gathering System. The San Juan natural gas gathering system, which we acquired in November 2002, is located in the San Juan Basin and has connections to approximately 10,000 wells. The system gathers natural gas from wells in the San Juan Basin to our Chaco plant and to the BP and Conoco owned Blanco plant. Over 70% of the gathering revenues from the system come from gathering agreements with Burlington, BP and Conoco. A significant portion of the rights-of-way underlying the San Juan gathering system on Native American lands expire in 2005. We believe we will be able to renew these rights-of-way on terms and conditions that will not materially adversely affect us.

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

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

- Carlsbad Natural Gas Gathering System. The Carlsbad gathering system is a natural gas gathering system located in the Permian Basin region of New Mexico and consists of approximately 563 miles of predominantly 4-inch to 12-inch pipelines.

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

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

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

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

GulfTerra Alabama Intrastate System. GulfTerra Alabama Intrastate is a natural gas pipeline system that serves the coal bed methane producing regions of Alabama. GulfTerra Alabama Intrastate provides marketing services through the purchase of natural gas from regional producers and others, and sale of natural gas to local distribution companies and others.

Viosca Knoll Gathering System. The Viosca Knoll gathering system is an offshore natural gas gathering system that connects the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico with the facilities of a number of major interstate pipelines. In the fourth quarter of 2003, we completed a 37-mile gas pipeline extension of our Viosca Knoll gathering system with capacity to handle 160 MMcf/d of natural gas production from Murphy Exploration and Production Company's Medusa field in the Gulf of Mexico. Production from the Medusa field into our pipeline extension began in November 2003. TotalFinaElf's Matterhorn field was also connected to our Viosca Knoll gathering system in 2003. TotalFinaElf, at their expense, constructed a gathering pipeline from their Matterhorn tension leg platform to our gathering system. Production from the Matterhorn field into the Viosca Knoll gathering system also began in November 2003.

High Island Offshore System. HIOS is an offshore natural gas transmission system that transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island, and East Breaks areas of the Gulf of Mexico to numerous downstream pipelines, including the ANR and Tennessee Gas pipelines owned by El Paso Corporation.

East Breaks System. The East Breaks natural gas gathering system connects the Hoover-Diana deepwater platform, owned by subsidiaries of ExxonMobil and BP and located in Alaminos Canyon Block 25, to HIOS.

Falcon Gas Pipeline. The Falcon gas pipeline gathers Pioneer Natural Resources' natural gas that is processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located on the Brazos Addition Block 133 platform.

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

Natural Gas Processing and Treating Facilities

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

	Processing		Treating		
	Chaco	**Indian Basin**[1]	**Coyote**[2]	**Waha**	**Rattlesnake**
Ownership interest	100%	42.3%	50%	100%	100%
Location of facility	New Mexico	New Mexico	Colorado	Texas	New Mexico
In-service date	1996	1964	1996	1966	1999
Date acquired	2001	2002	2002	2002	2002
Approximate capacity[3]	650	300	250	285	58
Average utilization rates for the year ended:					
December 31, 2003	88%	91%	N/A[4]	59%	58%
December 31, 2002	90%	93%	N/A[4]	54%	61%[5]
December 31, 2001	89%	93%	79%	61%	95%

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

(2) In November 2002, we acquired our interest in Coyote Gas Treating, LLC. The average utilization rates were calculated with 100 percent of volumes and capacity.

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

(4) Effective January 2002, Coyote Gas Treating, LLC entered into a five year operating lease agreement. Under the terms of the lease, Coyote Gas Treating, LLC receives fixed monthly lease payments of $600 thousand. We no longer receive volume data from the operator because our proportionate share of the revenues is now based on the fixed lease payments.

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

The Chaco cryogenic natural gas processing plant is the fifth largest natural gas processing plant in the United States measured by liquids produced. The Chaco plant is a state-of-the-art cryogenic plant located in the San Juan Basin in New Mexico that uses high pressures and extremely low temperatures to remove water, impurities and excess hydrocarbon liquids from the raw natural gas stream and to recover ethane, propane and the heavier hydrocarbons. It is capable of processing up to 650 MMcf/d of natural gas and extracting up to 50 MBbls/d of NGL.

Construction Projects

Phoenix Gathering System. We are constructing and will own 100 percent of a new $66 million gathering system, to gather natural gas production from the Red Hawk Field located in the Garden Banks area of the Gulf of Mexico. We have entered into related agreements with subsidiaries of Kerr-McGee Corporation and Devon Energy, Inc., which each hold a 50-percent working interest in the Red Hawk Field. Kerr-McGee and Devon have dedicated multiple blocks at and in the proximity of the Red Hawk Field to this pipeline for the life of the reserves, subject to certain release provisions. The 76-mile pipeline, capable of transporting up to approximately 450 MMcf/d of natural gas, will originate in 5,300 feet of water at the Red Hawk platform and connect to the ANR Patterson Offshore Pipeline system at Vermillion Block 397. We plan to place the new pipeline in service mid-year 2004. As of December 31, 2003, we have spent approximately $51.7 million related to this pipeline, which is in the construction stage. We expect to receive contributions in aid of construction from ANR Pipeline Company, a subsidiary of El Paso Corporation, of $6.1 million, of which $3.0 million has been collected, for the benefits of increased volumes they expect to transport on their pipeline as a result of our construction of this pipeline.

Marco Polo — Gas Gathering System. We are constructing and will own 100 percent of a 75-mile, 18-inch and 20-inch natural gas gathering system to support the Marco Polo tension-leg platform (TLP). The natural gas gathering system, with a maximum capacity of 400 MMcf/d, will gather natural gas from the Marco Polo platform in Green Canyon Block 608 and transport it to the Typhoon natural gas gathering system in Green Canyon Block 237. We intend to integrate the Marco Polo natural gas gathering system and Typhoon natural gas gathering system. This gathering system is expected to be completed and placed in service mid-year 2004, and is expected to cost $72 million to construct. We incurred higher costs of $4 million than originally anticipated as the result of installation timing conflicts between the Marco Polo TLP installation and the Marco Polo gas pipeline installation. As of December 31, 2003, we have spent approximately $47.0 million on this gathering system, which is in the construction stage. Additionally, we received contributions in aid of construction from ANR Pipeline Company and El Paso Field Services, subsidiaries of El Paso Corporation, totaling $17.5 million for the benefits of increased volumes they anticipate receiving on their facilities as a result of our construction of the natural gas pipeline.

San Juan Optimization Project. In May 2003, we commenced a $43 million project relating to our San Juan Basin assets. The project is expected to be completed in stages through 2006. The project is expected to result in increased capacity of up to 130 MMcf/d on the San Juan gathering system and increased market opportunities through a new interconnect at the tailgate of our Chaco plant. As of December 31, 2003, we have spent approximately $1.8 million related to this project.

Markets and Competition

Each of our natural gas pipeline systems is located at or near natural gas production areas that are served by other pipelines, and face competition from both regulated and unregulated systems.

Our gathering and transportation agreements have varying terms. Our offshore gathering and transportation arrangements tend to have longer terms, often involving life-of-reserve commitments with both firm and interruptible components, and our onshore gathering and transportation arrangements generally have terms from one month to several years. With respect to the San Juan gathering system, approximately 70 percent of the volume in 2003 and 2002 is attributable to three customers, Burlington Resources, ConocoPhillips and BP. These contracts expire in December of 2008, 2006 and 2006. The following table indicates the percentage revenue generated by each contract in relation to the indicated denominator for the years ended December 31, 2003 and 2002:

Base Revenue	Burlington Resources	ConocoPhillips	BP	Total
2003				
San Juan gathering revenue	29.7%	25.7%	17.3%	72.7%
Total revenue of natural gas pipelines and plants segment	6.8%	5.8%	3.9%	16.5%
2002				
San Juan gathering revenue[(1)]	30.6%	20.9%	14.5%	66.0%
Total revenue of natural gas pipelines and plants segment[(1)]	8.6%	5.8%	4.0%	18.4%

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

For a discussion of our significant customers, see Item 8, Financial Statements and Supplementary Data, Note 14.

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

Regulatory Environment

Our natural gas pipeline systems are subject to the Natural Gas Pipeline Safety Act of 1968 and the Pipeline Safety Improvement Act of 2002, which establishes pipeline and liquified natural gas plant safety requirements. All of our offshore pipeline systems are subject to regulation under the Outer Continental Shelf Lands Act, which calls for nondiscriminatory transportation on pipelines operating in the outer continental shelf region of the Gulf of Mexico. Each of the pipeline systems has continuous inspection and compliance programs designed to keep our facilities in compliance with pipeline safety and pollution control requirements. We believe that our pipeline systems are in material compliance with the applicable requirements of these regulations.

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

Our HIOS system is also subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a separate FERC approved tariff that governs its operations, terms and conditions of service and rates. The natural gas pipeline industry has historically been heavily regulated by federal and state governments, and we cannot predict what further actions FERC, state regulators, or federal and state legislators may take in the future. We timely filed a required rate case for our HIOS system on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee, and changes to depreciation rates and negative salvage amortization. HIOS' filing reflects a zero rate base; therefore, a management fee in place of a return on rate base has been requested. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. As of July 1, 2003, HIOS implemented the requested rates, subject to a refund, and has established a reserve for its estimate of its refund obligation. We will continue to review our expected refund obligation as the rate case moves through the hearing process and may increase or decrease the amounts reserved for refund obligation as our expectation changes. The FERC has conducted a hearing on this matter and an initial decision is expected to be issued in April 2004.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast region (and these assets) in late September and early October of 2002. As of December 31, 2003, we had recorded fuel differences of approximately $8.2 million, which is included in other non-current assets. We are currently in discussions with the FERC as well as our customers regarding the potential collection of some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers will negatively impact our earnings.

The FERC has issued the final rule regarding marketing affiliates which will affect our HIOS operations. See Part II, Item 8, Financial Statements and Supplementary Data, Note 11 — Commitments and Contingencies — Rates and Regulatory Matters.

GulfTerra Texas' FERC Section 311 service rates are subject to FERC rate jurisdiction. In December 1999, GulfTerra Texas filed a petition with the FERC for approval of its rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to GulfTerra Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering services. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. GulfTerra Texas has established a reserve for refunds. In July 2002, GulfTerra Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. In February 2004, the FERC issued an order denying GulfTerra Texas' request for rehearing and ordered GulfTerra Texas to file, within 45 days from the issuance of the order, a calculation of refunds and a refund plan. Additionally, the FERC ordered GulfTerra Texas to file a new rate case or justification of existing rates within three years from the date of the order.

In July 2002, Falcon Gas Storage Company, Inc., a competitor, also requested late intervention and rehearing of the order. Falcon asserts that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering imbalance management services. The FERC denied Falcon's late intervention in February 2004. Falcon Gas Storage and its affiliate Hill-Lake Gas Storage, L.P. filed a formal complaint in March 2003 at the Railroad Commission of Texas claiming that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering hourly imbalance management services on the GulfTerra Texas system. GulfTerra Texas filed a response specifically denying Falcon's assertions and requesting that the complaint be denied. The Railroad Commission has set their case for hearing beginning on April 13, 2004. The City Board of Public Service of San Antonio has filed an intervention in opposition to Falcon's complaint.

Environmental

Our natural gas pipelines and plants are subject to various safety and environmental statutes, including: the Natural Gas Act, the Natural Gas Policy Act, the Outer Continental Shelf Act, the Hazardous Materials Transportation Act, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and similar state statutes. We have ongoing programs designed to keep our natural gas pipelines and plants in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements. As of December 31, 2003, we had a reserve of approximately $21 million, included in other noncurrent liabilities, for environmental remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. We expect to make capital expenditures for environmental matters of approximately $3 million in the aggregate for the years 2004 through 2008, primarily to comply with clean air regulations. For a discussion of environmental regulations, see Environmental-Specific Regulations.

Maintenance

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

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

Oil and NGL Logistics

Offshore Oil Pipeline Systems

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

The following table and discussions describe our offshore oil pipelines.

	Poseidon	Allegheny	Typhoon[(1)]
Ownership interest	36%	100%	100%
In-service date	1996	1999	2001
Approximate capacity[(2)]	400	135	100
Aggregate miles of pipe	288	43	16
Average throughput for the years ended:[(3)]			
December 31, 2003	46	17	28
December 31, 2002	49	18	28
December 31, 2001	56	13	23

(1) The average throughput reflects 100 percent of the throughput. We acquired the Typhoon oil pipeline in November 2002.

(2) All capacity measures are on a MBbls/d basis. Poseidon, Typhoon and Allegheny's capacity measures can be achieved with the addition of pumps and use of friction reducers.

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

Poseidon System. Poseidon is a major offshore sour crude oil pipeline system that gathers production from the outer continental shelf in the Gulf of Mexico and transports onshore to Houma, Louisiana. The Poseidon system is owned by Poseidon Oil Pipeline Company, L.L.C., in which we own a 36 percent membership interest.

Allegheny System. Our Allegheny system is an offshore crude oil system consisting of 43 miles of 14-inch diameter pipeline that connects the Allegheny platform in the Green Canyon area of the Gulf of

Mexico with Poseidon at our 50 percent owned Ship Shoal 332 platform. Oil production from the Allegheny field is committed to this system. In addition, Allegheny will receive production gathered from our Marco Polo oil pipeline.

Typhoon Oil Pipeline. The Typhoon oil pipeline is an offshore crude oil pipeline consisting of 16 miles of 12-inch diameter pipeline that connects the Typhoon platform in the Green Canyon area of the Gulf of Mexico to the Shell Boxer platform. The Shell Boxer platform provides access to the Poseidon pipeline through a third party pipeline and access to two other third party pipelines.

NGL Transportation, Fractionation and Related Storage Facilities

We own more than 1,000 miles of intrastate NGL gathering and transportation pipelines and four fractionation plants located in Texas. The NGL pipeline system includes 379 miles of pipeline used to gather and transport unfractionated NGL from various processing plants to the Shoup Plant, located in Corpus Christi, which is the largest of our four fractionators. The pipeline system also includes over 660 miles of pipelines that deliver fractionated products such as ethane, propane, butane and natural gasoline to refineries and petrochemical plants from Corpus Christi to Houston and within the Texas City-Houston area, as well as to common carrier NGL pipelines. A key service provided for these customers is the seasonal movement of butanes to and from our leased underground NGL storage from refineries in Corpus Christi and Texas City. Our four Texas fractionation facilities have a combined capacity of 120 MBbls/d. Utilization rates in the fractionation industry can fluctuate dramatically from month to month, depending on the needs of our producer and refinery customers. However, the average utilization rate for three of our fractionators (excluding our Almeda fractionator) for the years ended December 31, 2003, 2002 and 2001 was 59 percent, 74 percent and 73 percent. The average utilization rate for the Almeda fractionator for the years ended December 31, 2003, 2002 and 2001 was 9 percent, less than 2 percent and 32 percent; the utilization for 2003 and 2002 was negatively impacted due to refurbishment work at the facility.

We also own a 3.3 MMBbl propane storage business operation located in Hattiesburg, Mississippi and a 3.2 MMBbl multi-product NGL storage facility near Breaux Bridge, Louisiana. We entered into a long-term propane storage agreement with Suburban Propane, L.P. for a portion of the storage capacity in Mississippi. A significant portion of the storage capacity of the Louisiana facility is committed under long-term storage agreements with a third party and with El Paso Field Services, a subsidiary of El Paso Corporation. Additionally, in November 2002, we acquired leases for two NGL storage facilities in Texas with aggregate capacity of approximately 18.1 MMBbls. The leases covering these facilities expire in 2006 and 2012.

Construction Projects

Cameron Highway. We are constructing the $458 million, 390-mile Cameron Highway oil pipeline with capacity of 500 MBbls/d, which is expected to be in service by the fourth quarter of 2004 and will provide producers with access to onshore delivery points in Texas. BP p.l.c., BHP Billiton and Unocal have dedicated 86,400 acres of property to this pipeline for the life of the reserves, including the acreage underlying their ownership interests in the Holstein, Mad Dog and Atlantis developments in the deeper water regions of the Gulf of Mexico.

Cameron Highway Oil Pipeline Company, our 50/50 joint venture with Valero Energy Corporation, will own the pipeline. We entered into producer agreements with three major anchor producers, BP Exploration & Production Company, BHP Billiton Petroleum (Deepwater), Inc. and Union Oil Company of California, which agreements were assigned to and assumed by Cameron Highway when Valero purchased its interest in the joint venture. The producer agreements require construction of the 390-mile Cameron Highway oil pipeline.

Cameron Highway has a $325 million project loan facility for the Cameron Highway oil pipeline system project, consisting of a $225 million construction loan and $100 million of senior secured notes. See Item 8, Financial Statements and Supplementary Data, Note 6, for additional discussion of the project loan facility. As of December 31, 2003, Cameron Highway has spent approximately $256 million (of which $85 million constituted equity contributions by us) related to this pipeline, which is in the construction stage. We and

Valero are obligated to make additional capital contributions to Cameron Highway if and to the extent that the construction costs for the pipeline exceed Cameron Highway's capital resources, including the initial equity contributions and proceeds from Cameron Highway's project loan facility.

Marco Polo — Oil Pipeline. We are constructing and will own 100 percent of a 36-mile, 14-inch oil pipeline to support the Marco Polo TLP. The oil pipeline will gather oil from the Marco Polo platform into our Allegheny pipeline in Green Canyon Block 164 with a maximum capacity of 120 MBbls/d. This pipeline is expected to be completed and placed in service in mid-year 2004, and is expected to cost $34 million to construct. We incurred higher costs than originally anticipated as a result of construction down time as a result of weather related delays and strong sea currents. As of December 31, 2003, we have spent approximately $25.7 million on this pipeline, which is in the construction stage.

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

Markets and Competition

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

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

Our Texas fractionation facilities typically experience a base utilization rate of approximately 60% to 70% because most of the natural gas in south Texas must be processed to extract heavier NGLs, such as butane and natural gasoline, in order to meet the quality specifications of the downstream natural gas pipelines; however, full utilization of our fractionation facilities occurs only when the natural gas producer can receive more net proceeds by maximizing the extraction and selling the lighter NGLs, such as ethane and propane, contained in the raw natural gas stream. The spread between natural gas and NGL prices varies from time to time depending on a complex number of factors, including (1) natural gas supply, demand and storage inventories, (2) NGL supply, demand and storage inventories and (3) crude oil prices. Given these intricate factors, the spread between natural gas and NGL prices exhibits weekly and monthly volatility. If a natural gas producer determines that this spread is too low, that producer will choose to use our facilities at only the minimum level required to meet downstream pipeline natural gas quality specifications. Regardless of the elections made by the producers, our fractionation facilities would continue to be operated, but at varying utilization levels. We will continue to incur operating costs regardless of the utilization level.

All of the capacity of our GTM Texas fractionation facilities is dedicated to a subsidiary of El Paso Corporation under a transportation and fractionation agreement that expires in 2021. In this agreement, all of the NGL derived from processing operations at seven natural gas processing plants in south Texas owned by subsidiaries of El Paso Corporation (which plants El Paso Corporation has agreed to sell to Enterprise in connection with our proposed merger) are delivered to our NGL transportation and fractionation facilities. Effectively, we will receive a fixed fee for each barrel of NGL transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. Until our merger with Enterprise closes, El Paso Corporation's subsidiary will bear substantially all of the risks and rewards associated with changes in the commodity prices for NGL.

For a discussion of our significant customers, see Item 8, Financial Statements and Supplementary Data, Note 14.

Regulatory Environment

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

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

Environmental

Our oil and natural gas logistics operations are subject to various safety and environmental statutes, including: the Outer Continental Shelf Act, the Hazardous Liquid Pipeline Safety Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Federal Water Pollution Control Act, the Oil Pollution Act of 1990, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act and similar state statutes. We have ongoing programs designed to keep our oil and NGL logistics operations in compliance with environmental and safety requirements, and we believe that our facilities are in material compliance with the applicable requirements. For a discussion of environmental regulations, see Environmental — Specific Regulations.

Maintenance

Each of our pipeline systems, our fractionation facilities and our processing facilities require regular maintenance. The interior of the GTM Texas, Allegheny, Typhoon and Poseidon pipelines is maintained through regular cleaning utilizing polyurethane pigs. Corrosion inhibitors are also injected into the GTM Texas system through the flow stream on a continuous basis. To maintain our pipeline integrity on our Poseidon, Allegheny and Typhoon oil pipeline systems, we use water sample analysis, electron microscope analysis and a rigid pigging schedule. Our Allegheny, Typhoon and Poseidon oil pipeline systems include platforms that are manned on a continuous basis. The personnel on board these platforms are responsible for site maintenance, operations of the platform facilities, measurement of the oil stream at the source of production and corrosion control.

Natural Gas Storage

We own the Petal and Hattiesburg salt dome natural gas storage facilities located in Mississippi, which are strategically situated to serve the Northeast, Mid-Atlantic and Southeast natural gas markets. In June 2002, we completed an 8.9 Bcf (6.3 Bcf working capacity) expansion of our Petal facility, including a

20,000 horsepower compression station and a 60-mile takeaway pipeline, including a 9,000 horsepower compression station. These two facilities have a combined current working capacity of 13.5 Bcf, and are capable of delivering in excess of 1.2 Bcf/d of natural gas into five interstate pipeline systems: Transco, Destin Pipeline, Gulf South Pipeline, Southern Natural Gas Pipeline and Tennessee Gas Pipeline. Additionally, we lease the Wilson natural gas storage facility. Each of these facilities is capable of making deliveries at the high rates necessary to satisfy peak requirements in the electric generation industry.

	Hattiesburg	Petal	Wilson[1]
Approximate acres	73	76	62
Year end 2003 working gas capacity (Bcf)	4.0	9.5	6.4

	Hattiesburg			Petal			Wilson		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
Firm storage									
Average working gas capacity available (Bcf)	4.0	4.0	4.3	9.5	6.4	3.2	6.4	6.4	6.4
Average firm subscription (Bcf)	3.9	4.0	4.3	8.9	5.6	2.6	6.2	5.8	3.0
Average monthly commodity volumes (Bcf)	1.4	2.2	1.4	2.5	1.7	0.5	0.3	—	—
Interruptible storage									
Contracted volumes (Bcf)	0.1	0.1	0.1	0.2	0.1	0.3	0.4	—	—
Average monthly commodity volumes (Bcf)	—	—	1.4	0.5	0.6	0.2	—	—	—

(1) We have the exclusive right to use the Wilson natural gas storage facility under an operating lease that expires in January 2008 and, subject to certain conditions, has one or more optional renewal periods of five years each at fair market rate at the time of renewal.

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

The Petal facility is less than one mile from the Hattiesburg facility and consists of two high-deliverability natural gas storage caverns. The Petal facility has an injection capacity in excess of 430 MMcf/d of natural gas and a withdrawal capacity of 865 MMcf/d of natural gas. The Petal capacity is 94 percent subscribed, with 7.0 Bcf dedicated under a 20-year fixed-fee contract to a subsidiary of The Southern Company, one of the largest producers of electricity in the United States, and 1.95 Bcf subscribed to BP Energy Company.

The Wilson facility interconnects with our Texas Intrastate systems and is located in Wharton County, Texas, and consists of four caverns. The facility has an injection capacity of 150 to 360 MMcf/d of natural gas and a maximum withdrawal capacity of 800 MMcf/d of natural gas. The Wilson capacity is currently 97 percent subscribed with long-term contracts expiring between 2006 and 2007.

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

Construction Projects

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

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

We are also considering converting our existing brine well at our propane storage caverns in Hattiesburg to natural gas service. This conversion would cost approximately $16 million and would create a new 1.8 Bcf working natural gas cavern that would be integrated into our Petal storage complex. We are currently negotiating with customers for the full 1.8 Bcf of capacity and expect, subject to final regulatory approval, to have the cavern in service during the fourth quarter of 2004.

Markets and Competition

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

Most of the capacity relating to the Petal facility is dedicated under a 20-year, fixed-fee contract. Most of the contracts relating to the Hattiesburg and Wilson natural gas storage assets are long term, expiring between 2005 and 2007. We believe that the existence of these long-term contracts for storage, and the location of our natural gas storage facilities should allow us to compete effectively with other companies who provide natural gas storage services. We believe that many of our natural gas storage contracts will be renewed, although we also expect that once these firm storage contracts have expired, we will experience greater competition for providing storage services. The competition we experience will be dependent upon the nature of the natural gas storage market existing at that time. In addition to long-term contracts, we actively market interruptible storage services at the Petal facility to enhance our revenue generating ability beyond the firm storage contracts.

For a discussion of our significant customers see Part II, Item 8, Financial Statements and Supplementary Data, Note 14.

Regulatory Environment

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

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

The FERC has issued the final rule regarding marketing affiliates which will affect our Petal operations. See Part II, Item 8, Financial Statements and Supplementary Data, Note 11.

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

Environmental

Our natural gas storage operations are subject to various safety and environmental statutes, including: the Natural Gas Act, the Natural Gas Policy Act, the Hazardous Materials Transportation Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Clean Water Act, the Endangered Species Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right-to-Know Act, and similar state statutes. We have ongoing programs designed to keep our storage operations in compliance with environmental and safety regulations, and we believe that our facilities are in material compliance with the applicable requirements. For a discussion of environmental regulation, see Environmental — Specific Regulations.

Maintenance

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

Platform Services

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

- interconnect the offshore pipeline grid;
- provide an efficient means to perform pipeline maintenance;
- locate compression, separation, production handling and other facilities; and
- conduct drilling operations during the initial development phase of an oil and natural gas property.

We have interests in seven multi-purpose offshore hub platforms in the Gulf of Mexico, including the Falcon Nest platform that we brought on line in March 2003 and the Marco Polo tension leg platform (TLP) that was installed in January 2004. These platforms were specifically designed to be used as hubs and production handling and pipeline maintenance facilities. Through these facilities, we are able to provide a variety of midstream services to increase deliverability for, and attract new volumes into, our offshore pipeline systems. The following table and discussions describe our platforms.

	East Cameron 373	Viosca Knoll 817	Ship Shoal 331(1)	Garden Banks 72	Ship Shoal 332(1)	Falcon Nest	Marco Polo(2)
Ownership interest	100%	100%	100%	50%	50%	100%	50%
In-service date	1998	1995	1994	1995	1985	2003	2004
Water depth (in feet)	441	671	376	518	438	389	4,300
Acquired (A) or constructed (C)	C	C	A	C	A	C	C
Approximate handling capacity:							
Natural gas (MMcf/d)	190	140	—	80	—	400	300
Oil and condensate (MBbls/d)	5	5	—	55	—	2	120

(1) Primarily serves as a junction platform for pipeline interconnects.
(2) The Marco Polo TLP is expected to be in service in the second quarter of 2004.

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

Viosca Knoll 817. The Viosca Knoll 817 platform is centrally located on the Viosca Knoll system. The platform serves as a base for landing deepwater production in the area, including ExxonMobil's, Shell's, and BP's Ram Powell development. A 7,000 horsepower compressor on the platform facilitates deliveries from the Viosca Knoll system to multiple downstream interstate pipelines. The platform is also used as a base for oil and natural gas production from our Viosca Knoll Block 817 lease and Walter Oil and Gas' Viosca Knoll 862 lease.

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

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

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

Falcon Nest. The Falcon Nest fixed-leg platform, located at Mustang Island Block 103, processes natural gas from Pioneer Natural Resources Company's Falcon Field located in East Breaks Blocks 579 and 580 and Harrier Field located in East Breaks Blocks 758 and 759. Pioneer has dedicated 69,120 acres of property to this platform for the life of the reserves.

Marco Polo Platform. We have installed the Marco Polo TLP, which has a maximum handling capacity of 120 MBbls/d of oil and 300 MMcf/d of natural gas. This TLP, which we expect to be in service in the second quarter of 2004, was designed and located to process oil and natural gas from Anadarko Petroleum Corporation's Marco Polo Field located in Green Canyon Block 608. Anadarko has dedicated 69,120 acres of property to this TLP, including the acreage underlying their Marco Polo Field, for the life of the reserves.

Anadarko will have firm capacity of 50 MBbls/d of oil and 150 MMcf/d of natural gas. The remainder of the platform capacity will be available to Anadarko for additional production and/or to third parties that have fields developed in the area. This TLP is owned by Deepwater Gateway, L.L.C., our 50 percent owned joint venture with Cal Dive International, Inc., a leading energy services company specializing in subsea construction and well operations. Anadarko will operate the Marco Polo TLP. The total cost of the project is expected to be $232 million, or approximately $116 million for our share. As of December 31, 2003, Deepwater Gateway has spent approximately $225 million on this TLP. Deepwater Gateway handed over operations of the Marco Polo TLP to Anadarko in the first quarter of 2004. Anadarko has installed a work-over rig and has commenced the completion of the Marco Polo wells.

Deepwater Gateway has a $155 million project finance loan to fund a substantial portion of the cost to construct the Marco Polo TLP and related facilities. See Item 8, Financial Statements and Supplementary Data, Note 6, for additional discussion of the project finance loan.

Markets and Competition

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

Non-Segment Activity

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

Producing Properties

The following table sets forth information regarding our producing properties as of December 31, 2003.

	Garden Banks Block 72	Garden Banks Block 73[1]	Garden Banks Block 117	Viosca Knoll Block 817/861[2]	West Delta Block 35[3]
Working interest	50%	—	50%	100%	38%
Net revenue interest	40.2%	2.5%	37.5%	80%	29.8%
In-service date	1996	2000	1996	1995	1993
Net acres	2,880	—	2,880	11,520	1,894
Distance offshore (in miles)	120	115	120	40	10
Water depth (in feet)	519	743	1,000	671	60
Producing wells	5	—	2	7	3
Cumulative production:					
Natural gas (MMcf)	5,554	219	2,335	64,220	3,169
Oil (MBbls)	1,651	—	1,316	217	16

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

(2) 25 percent of our 100 percent working interest in Viosca Knoll Block 817/861 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, 2003, the unpaid portion of the production payment obligation totaled $9.1 million.

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

Acreage and Wells. The following table sets forth our developed and undeveloped oil and natural gas acreage as of December 31, 2003. 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	28,040	19,174
Undeveloped acreage	—	—
Total acreage	28,040	19,174

Our gross and net ownership in producing wells in which a working interest is owned directly by us at December 31, 2003, 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.

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)		
	2003	2002	2001	2003	2002	2001
Net production[(1)]	242	318	343	1,789	3,237	4,038
Average realized sales price[(1)]	$31.31	$23.36	$23.47	$ 5.62	$ 3.12	$ 4.52
Average realized production costs[(2)]	$10.07	$15.01	$16.11	$ 1.68	$ 2.50	$ 2.68

(1) The information regarding net production and average realized sales prices includes overriding royalty interests. Net oil and natural gas production volumes from our overriding royalty interest in the Prince Field were approximately 50 MBbls and 37 MMcf in 2002 and 37 MBbls and 32 MMcf in 2001.

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

	Oil (MBbls)			Natural Gas (MMcf)		
	2003	2002	2001	2003	2002	2001
Average consolidated realized production costs[(1)]	$10.07	$ 7.13	$ 6.35	$ 1.68	$ 1.19	$ 1.06

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

The relationship between average sales prices and average production costs depicted by the table above is not necessarily indicative of true results of operations.

Markets and Competition

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

Regulatory Environment

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

- requiring permits for the drilling of wells;
- maintaining bonds and insurance requirements in order to drill or operate wells;
- drilling and casing wells;
- using and restoring the surface of properties upon which wells are drilled; and
- plugging and abandoning of wells.

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

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

Environmental

Our production and development operations are subject to various federal and state safety and environmental statutes. For a discussion of environmental regulations, see Environmental — Specific Regulations.

Operating Environment

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

Environmental

General

We are subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will make accruals accordingly. A description of our environmental matters is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 11.

Specific Regulations

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

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

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

Air. Our operations may be subject to the Clean Air Act, or CAA, and other federal and state statutes and regulations, which may impose certain pollution control requirements with respect to air emissions from operations, particularly in instances where a company constructs a new facility or modifies an existing facility. We may also be required to incur certain capital expenditures in the next several years estimated to be approximately $3 million in aggregate for the years 2004 through 2008 for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

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

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

Employees

Neither we nor our general partner has any employees. Our administrative and operating personnel are provided by subsidiaries of El Paso Corporation through a general and administrative services agreement with our general partner. We reimburse our general partner for all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on behalf of, us, including expenses incurred by us under the general and administrative services agreement.

Available Information

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

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

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

Substantially all of our assets and the assets of our subsidiaries (other than our unrestricted subsidiaries, Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.) are pledged as collateral under our credit facility. In addition, our Poseidon, Cameron Highway and Deepwater Gateway joint ventures currently have credit arrangements under which substantially all of their assets are pledged. For a discussion of our and our joint ventures' credit arrangements, see Item 8, Financial Statements and Supplementary Data, Note 6.

ITEM 3. LEGAL PROCEEDINGS

See Part II, Item 8, Financial Statements and Supplementary Data, Note 11.

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 "GTM". As of March 10, 2004, we had 738 unitholders of record and the closing price on the NYSE for common units was $41.09 per unit.

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

	Common Units		Distributions Declared per Unit
	High	Low	Common
2003			
Fourth Quarter	$42.930	$37.910	$0.710
Third Quarter	40.469	37.016	0.700
Second Quarter	38.000	30.960	0.675
First Quarter	32.590	27.820	0.675
2002			
Fourth Quarter	$32.700	$26.000	$0.675
Third Quarter	35.800	20.500	0.650
Second Quarter	38.680	29.990	0.650
First Quarter	38.540	31.650	0.625

In January 2004, we declared a quarterly distribution of $0.71 per common unit which was paid on February 15, 2004, to unitholders of record on January 30, 2004. Our quarterly distribution rate represents an annual distribution rate of $2.84 per unit, up $0.14 compared to the annual rate of $2.70 declared in the fourth quarter of 2002.

Cash Distributions

We make quarterly distributions of 100 percent of our available cash, as defined in our partnership agreement, to our unitholders and to our general partner. Our available cash consists generally of all cash receipts plus reductions in reserves less all cash disbursements and net additions to reserves. Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of any of our agreements or obligations.

The holders of common units and our general partner are not entitled to arrearages of minimum quarterly distributions. Our distributions are effectively made 99 percent to limited unitholders and one percent to our general partner, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Incentive distributions to our general partner increase to 14 percent, 24 percent and 49 percent based on incremental distribution thresholds. Since 1998, quarterly distributions to common unitholders have been in excess of the highest incentive threshold of $0.425 per unit, and as a result, our general partner has received 49 percent of the incremental amount. For the year ended December 31, 2003, we paid $168.2 million in distributions to our common unitholders, including El Paso Corporation, and $70.2 million to our general partner related to incentive distributions as well as our general partner's one percent income distribution.

We issued Series C units to a subsidiary of El Paso Corporation in connection with our November 2002 San Juan assets acquisition. See Series C Units below for a discussion of these units. Also, see Item 8, Financial Statements and Supplementary Data, Note 8, for a discussion relating to cash distributions.

Recent Offerings of Common Units

During 2003, we issued the following common units in public offerings:

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

(1) Offering includes 80 Series F convertible units, which are described below.

In addition to our public offerings of common units, in October 2003 we sold 3,000,000 common units privately (in an exempt transaction under Section 4(2) of the Securities Act of 1933 as a transaction not involving a public offering) to Goldman Sachs in connection with their purchase of a 9.9 percent membership interest in our general partner (which interest was repurchased in connection with the signing of the Enterprise merger agreement). We used the net proceeds of $111.5 million from that private sale to temporarily reduce amounts outstanding under our revolving credit facility and, in December 2003, to redeem a portion of our outstanding senior subordinated notes.

In connection with the offerings in 2003, our general partner contributed to us approximately $2.0 million of our Series B preference units and cash of $3.1 million in order to maintain its one percent general partner interest.

Series B Preference Units

In August 2000, we issued to a subsidiary of El Paso Corporation 170,000 cumulative redeemable Series B preference units, with a value of $170 million, in exchange for the Petal and Hattiesburg natural gas storage businesses. In October 2001, we redeemed 44,608 of the Series B preference units for their liquidation value of $50 million, including accrued distributions of approximately $5.4 million, bringing the total number of units outstanding to 125,392. In October 2003, we redeemed all 123,865 of our remaining outstanding Series B preference units for $156 million, a 7 percent discount from their liquidation value of $167 million. For this redemption, we used borrowings under our revolving credit facility. We reflected the discount as an increase to the common units capital, Series C units capital and to our general partner's capital accounts.

Series C Units

In November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of Series C units at a price of $32 per unit, $350 million in the aggregate, as part of our consideration paid for the San Juan assets. The issuance of the Series C units was an exempt transaction under Section 4(2) of the Securities Act of 1933 as a transaction not involving a public offering. The Series C units are similar to our existing common units, except that the Series C units are non-voting. After April 30, 2003, the holder of Series C units has the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit will convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C units will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate can increase on April 30, 2004, to 110 percent of the common unit distribution rate and on April 30, 2005, to 115 percent of the common unit distribution rate. The holder of the Series C units has thus far not requested a vote to convert the Series C units into common units. As part of the proposed merger with Enterprise, immediately prior to the closing of the merger, Enterprise will purchase from a subsidiary of El Paso Corporation all of our outstanding Series C units. These units will not be converted to Enterprise common units in the merger but rather will remain limited partnership interests in GulfTerra after the closing of the merger transaction and, as such, will lose their GulfTerra common unit conversion and distribution rights.

Series F Convertible Units

In May 2003, we issued 1,118,881 common units and 80 Series F convertible units in a registered offering to a large institutional investor for approximately $38.3 million net of offering costs. Our Series F convertible units are not listed on any securities exchange or market. Each Series F convertible unit is comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that have identical terms except for vesting and termination dates and the number of underlying common units into which they may be converted. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until the date we merge with Enterprise (subject to other defined extension rights). The Series F2 units are convertible into up to $40 million of common units. The Series F2 units terminate on March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser of (i) the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75, or (ii) the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units; (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units assuming we had received a conversion notice on December 31, 2003 and March 2, 2004, was $40.38 and $39.40. The Series F convertible units may be converted into a maximum of 8,329,679 common units. Holders of Series F convertible units are not entitled to vote or receive distributions. The $4.1 million value associated with the Series F convertible units is included in partners' capital as a component of common units capital.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26.00 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at December 31, 2003.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million.

Any Series F convertible units outstanding at the merger date will be converted into rights to receive Enterprise common units, subject to restrictions governing the Series F units. The number of Enterprise common units and the price per unit at conversion will be adjusted based on the 1.81 exchange ratio.

Equity Compensation Plans

Refer to the information included in Part III, Item 12, Security Ownership of Certain Beneficial Owners and Management, regarding securities authorized for issuance under equity compensation plans.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per unit amounts)				
Operating Results Data[1]:					
Operating revenues[2]	$871,489	$457,390	$193,406	$112,415	$63,659
Income from continuing operations	161,449	92,552	54,052	20,749	18,817
Basic and diluted income (loss) from continuing operations per common unit[3]	1.30	0.80	0.35	(0.02)	(0.34)
Distributions per common unit	2.76	2.60	2.31	2.15	2.10
Distributions per preference unit[4]	—	—	—	0.83	1.10

	As of December 31,				
	2003	2002	2001	2000	1999
	(In thousands)				
Financial Position Data[1]:					
Total assets	$3,321,580	$3,130,896	$1,357,420	$869,471	$583,585
Revolving credit facility	382,000	491,000	300,000	318,000	290,000
Senior secured term loans[5]	300,000	557,500	—	—	—
Limited recourse term loan[6]	—	—	95,000	45,000	—
Long-term debt[7]	1,129,807	857,786	425,000	175,000	175,000
Partners' capital[8]	1,252,586	949,852	500,726	311,071	96,489

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

- the San Juan assets in November 2002;
- the EPN Holding assets in April 2002;
- the Chaco plant and the remaining 50 percent interest we did not already own in Deepwater Holdings in October 2001;
- GTM Texas in February 2001;
- the Petal and Hattiesburg natural gas storage facilities in August 2000;
- GulfTerra Alabama Intrastate 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 assets and entities are included in our results prospectively from the purchase date. In addition, operating results and financial position reflect the sale of our direct and indirect interests in several offshore Gulf of Mexico assets in January and April of 2001 as a result of an FTC order related to El Paso Corporation's merger with The Coastal Corporation.

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

(3) Reflects our 1999 adoption of a preferable accounting method for allocating partnership income to our general partner and our preference and common unitholders. We changed our method of allocating net income to our partners' capital accounts from a method where we allocated income based on percentage ownership and proportionate share of cash distributions, to a method where income is allocated to the partners based upon the change from period to period in their respective claims on our book value capital. We believe that the new income allocation method is preferable because it more accurately reflects the income allocation provisions called for under the partnership agreement and the resulting partners' capital accounts are more reflective of a partner's claim on our book value capital at each period end. This change in accounting had no impact on our consolidated net income or our consolidated total partners' capital for any period presented. The impact of this change in accounting has been recorded as a cumulative effect adjustment in our income allocation for the year ended December 31, 1999. The effect of adopting this change in accounting, excluding the cumulative adjustment, was to reduce basic and diluted net income per limited partner unit by $0.33 for the year ended December 31, 1999.

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

(5) The decrease in 2003 reflects:

- Repayment of our $160 million GulfTerra Holding term credit facility; and
- Repayment of our $237.5 million senior secured acquisition term loan.

These decreases in 2003 are offset by a increase in the term loan portion of our credit facility from $160 million to $300 million.

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

(7) The increase in 2003 reflects:

- the issuance of our $250 million senior notes in July 2003;
- the issuance of our $300 million senior subordinated notes in March 2003; and
- the redemption of a portion of our outstanding senior subordinated notes in December 2003.

The increase in 2002 reflects the issuance of our $200 million $10\frac{5}{8}$% senior subordinated notes in November 2002 and the issuance of our $230 million $8\frac{1}{2}$% senior subordinated notes in May 2002. The increase in 2001 reflects the issuance of our $250 million $8\frac{1}{2}$% senior subordinated notes in May 2001.

(8) Reflects the issuance of:

- 7.8 million common units in October 2003;
- 0.5 million common units in August 2003;
- 1.2 million common units in June 2003;
- 1.1 million common units in May 2003;
- 3.5 million common units in April 2003;
- 10.9 million Series C units acquired by a subsidiary of El Paso Corporation in November 2002;
- 4.1 million common units, which included 1.1 million common units purchased by an affiliate of our general partner in April 2002;
- 5.6 million common units, which included 1.5 million common units purchased by an affiliate of our general partner in October 2001;
- 2.3 million common units in March 2001;
- $170 million Series B preference units to a subsidiary of El Paso Corporation in August 2000; and
- 4.6 million common units in July 2000.

In October 2003, we redeemed all 123,865 of our remaining outstanding Series B preference units for $156 million, a 7 percent discount from their liquidation value of $167 million. Also, we redeemed $50 million in 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

Our Management's Discussion and Analysis includes forward-looking statements that are subject to risks and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors, including those discussed beginning on page 56.

General

Our objective is to operate as a growth-oriented MLP with a focus on increasing our cash flow, earnings and return to our unitholders by becoming one of the industry's leading providers of midstream energy services. Our strategy is to maintain and grow a diversified, balanced base of strategically located and efficiently operated midstream energy assets with stable and long-term cash flows. Our strategy contemplates substantial growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets, while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively, diversify our asset portfolio and, thereby, provide more stable cash flow.

Merger with Enterprise

To further our business strategy, we executed definitive agreements with Enterprise and El Paso Corporation, on December 15, 2003, to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs with an enterprise value of approximately $13 billion as of December 15, 2003. Subject to any divestitures required under the Hart-Scott-Rodino Act, the combined partnership will own or have interests in:

- 17,000 miles of natural gas pipelines;
- 13,000 miles of NGL and petrochemical pipelines;
- 340 miles of large capacity crude oil pipelines in the Gulf of Mexico;
- 164 MMBbls of NGL storage capacity;
- 23 Bcf of natural gas storage capacity;
- Seven offshore Gulf of Mexico hub platforms;
- NGL import and export terminals on the Houston Ship Channel;
- 19 NGL fractionation plants with a net capacity of approximately 650 MMBbls/d; and
- 24 natural gas processing plants with a net capacity of 6.0 Bcf/d.

The general partner of the combined partnership will be jointly owned by affiliates of El Paso Corporation and privately-held Enterprise Products Company, with each owning a 50-percent interest.

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

The definitive agreements include three transactions. In the initial transaction, completed and funded on December 15, 2003, a subsidiary of Enterprise acquired a 50-percent, limited voting interest in our general partner, GulfTerra Energy Company, L.L.C., for $425 million in cash. Prior to the closing of this transaction, El Paso Corporation reacquired the 9.9-percent ownership interest in our general partner held by Goldman Sachs. As a result of this initial step, our general partner is owned 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise. El Paso Corporation's subsidiary continues to serve as the managing member of our general partner, and the Enterprise affiliate member's rights are limited to protective consent rights on certain transactions affecting us or our general partner.

In the second transaction, which will occur immediately prior to the merger, El Paso Corporation will contribute its 50-percent ownership interest in our general partner to Enterprise Products GP, LLC, the current general partner of Enterprise and continuing general partner of the merged partnerships. In exchange, El Paso Corporation will receive a 50-percent interest in Enterprise's general partner. The remaining 50 percent of the Enterprise general partner will continue to be owned by affiliates of Enterprise Products Company. The Enterprise general partner will then contribute this 50-percent ownership interest in our general partner to Enterprise for no consideration. In addition, Enterprise will pay El Paso Corporation $500 million in cash for approximately 13.8 million units, which include 2.9 million of our common units and all of our Series C units.

In the final transaction, we will merge with a wholly-owned subsidiary of Enterprise, with us surviving the merger as a wholly-owned subsidiary of Enterprise. Under the terms of the merger agreement, our unitholders will receive 1.81 Enterprise common units for each GulfTerra common unit, which represents a premium of approximately 2.2 percent based on the closing prices of their respective common units on December 12, 2003, the last trading day before the agreements were signed. The remaining approximately 7.5 million GulfTerra common units owned by El Paso Corporation will be exchanged for Enterprise common units based on the 1.81 exchange ratio. The GulfTerra common units and Series C units acquired by Enterprise for cash will not convert into Enterprise common units and, after the closing of the merger, will lose all distribution rights. After the merger, El Paso Corporation will own approximately 14.9 million common units of Enterprise.

The completion of the merger is subject to the approval of the unitholders of both Enterprise and GulfTerra along with customary regulatory approvals, including that under the Hart-Scott-Rodino Antitrust Improvements Act. Completion of the merger is expected to occur during the second half of 2004.

In connection with the closing of the merger, Enterprise will acquire nine natural gas processing plants from El Paso Corporation for $150 million in cash. These plants, located in South Texas, have historically been associated with and are integral to our Texas intrastate natural gas pipeline and NGL fractionation and pipeline systems.

Under the terms of the merger agreement, the board of directors of the general partner of Enterprise will consist of ten directors, of which five will be designated by Enterprise Products Company and five will be designated by El Paso Corporation. Six of the directors (three of those designated by Enterprise Products Company and three of those designated by El Paso Corporation) will be independent directors meeting the requirements established by the NYSE. Two of the directors designated by Enterprise initially will be Dan L. Duncan, the current Chairman of Enterprise's general partner, and O.S. Andras, the current Chief Executive Officer of Enterprise's general partner. Two of the directors designated by El Paso Corporation initially will be Robert G. Phillips, our general partner's current Chairman and Chief Executive Officer, and D. Dwight Scott, Executive Vice President and Chief Financial Officer of El Paso Corporation. Following the merger, Mr. Duncan will be Chairman, Mr. Andras will be Vice Chairman and Chief Executive Officer and Mr. Phillips will be President and Chief Operating Officer of Enterprise's general partner. If the approval of any matter that is before the board is equally split for and against, Mr. Duncan will cast the deciding vote.

Because the closing of the merger will be a change of control, and thus a default, under our credit facility, we will either repay or amend that facility prior to the closing. In addition, because the merger closing will constitute a change of control under our indentures, we will be required to offer to repurchase our outstanding senior subordinated notes (and possibly our senior notes) at 101 percent of their principal amount after the closing. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the close of the merger. We and Enterprise can agree on the date of the merger closing after the receipt of all necessary approvals. We do not intend to close until appropriate financing is in place.

Under the merger agreement, we are required to generally conduct our business in the ordinary course consistent with past practice. In addition, we may not take any of the following actions without Enterprise's consent:

- issue or sell any equity securities other than (1) pursuant to our employee benefit plans, options, and Series F convertible units and (2) up to $100 million of common units;
- declare or pay distributions in excess of $0.71 per common unit (unless required by our partnership agreement);
- acquire assets for consideration in excess of $50 million or $100 million in the aggregate;
- sell assets with a fair market value in excess of $10 million or $25 million in the aggregate;
- make investments, other than required by joint venture agreements, in excess of $25 million in aggregate;
- incur additional indebtedness other than (1) ordinary course borrowings under our revolving credit facility and (2) up to $100 million in principal amount of additional indebtedness with a maturity of no more than three years and no repayment penalty; and
- make capital expenditures in excess of $5 million or $25 million in the aggregate other than (1) as required on an emergency basis and (2) those planned expenditures previously disclosed to Enterprise.

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

Capital Projects

During 2003, we integrated our 2002 asset acquisitions of the EPN Holding and the San Juan assets. The assets acquired in these acquisitions performed well in 2003 and are now the core of our business. They provide us the stable cash flow to use, along with borrowings under credit facilities and other debt and equity transactions, to fund our midstream projects underway in the Gulf of Mexico, which have gross estimated capital costs of $862 million, including 426 miles of oil pipelines and 151 miles of natural gas pipelines.

Cameron Highway. We are constructing the $458 million, 390-mile Cameron Highway oil pipeline with capacity of 500 MBbls/d, which is expected to be in service by the fourth quarter of 2004, and will provide producers with access to onshore delivery points in Texas. BP p.l.c., BHP Billiton and Unocal have dedicated 86,400 acres of property to this pipeline for the life of the reserves, including the acreage underlying their ownership interests in the Holstein, Mad Dog and Atlantis developments in the deeper water regions of the Gulf of Mexico.

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

In July 2003, we sold a 50 percent interest in Cameron Highway to Valero for $86 million, forming a joint venture with Valero. Valero paid us approximately $70 million at closing, including $51 million representing

50 percent of the capital investment expended through that date for the pipeline project, and we recognized $19 million as a gain from the sale of long-lived assets. In addition, Valero will pay us $5 million once the system is completed and an additional $11 million by the end of 2006. We expect to reflect these additional amounts as gains from the sale of long-lived assets in the periods they are received. In connection with the formation of the Cameron Highway joint venture, Valero agreed to pay their proportionate share of the pipeline construction costs that exceed Cameron Highway's capital resources, including the initial equity contributions and proceeds from Cameron Highway's project loan facility.

The Cameron Highway oil pipeline system project is expected to be funded with $169 million equity through capital contributions from us and Valero, the two Cameron Highway partners, which contributions have already been made and the remainder from borrowings by Cameron Highway under its $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes. As of December 31, 2003, Cameron Highway has spent approximately $256 million related to this pipeline, which is in the construction stage. We and Valero are obligated to make additional capital contributions to Cameron Highway if and to the extent that the construction costs for the pipeline exceed Cameron Highway's capital resources, including the initial equity contributions and proceeds from Cameron Highway's project loan facility.

Marco Polo Platform. We have installed the Marco Polo TLP, which has a maximum handling capacity of 120 MBbls/d of oil and 300 MMcf/d of natural gas. This TLP, which we expect to be in service in the second quarter of 2004, was designed and located to process oil and natural gas from Anadarko Petroleum Corporation's Marco Polo Field located in Green Canyon Block 608. Anadarko has dedicated 69,120 acres of property to this TLP, including the acreage underlying their Marco Polo Field, for the life of the reserves. Anadarko will have firm capacity of 50 MBbls/d of oil and 150 MMcf/d of natural gas. The remainder of the platform capacity will be available to Anadarko for additional production and/or to third parties that have fields developed in the area. This TLP is owned by Deepwater Gateway, L.L.C., our 50 percent owned joint venture with Cal Dive International, Inc., a leading energy services company specializing in subsea construction and well operations. Anadarko will operate the Marco Polo TLP. The total cost of the project is expected to be $232 million, or approximately $116 million for our share. As of December 31, 2003, Deepwater Gateway has spent approximately $225 million on this TLP. Deepwater Gateway handed over operations of the Marco Polo TLP to Anadarko in the first quarter of 2004. Anadarko has installed a work-over rig and has commenced the completion of the Marco Polo wells.

In August 2002, Deepwater Gateway obtained a $155 million project finance loan at a variable interest rate from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. The loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2003, Deepwater Gateway had $155 million outstanding under the project finance loan and had not paid us, our joint venture partner or any of our subsidiaries any distributions.

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

Marco Polo Oil and Gas Pipelines. We are constructing and will own 100 percent of a 36-mile, 14-inch oil pipeline and a 75-mile, 18 and 20-inch natural gas gathering system to support the Marco Polo TLP. The natural gas gathering system, with a maximum capacity of 400 MMcf/d, will gather natural gas from the Marco Polo platform in Green Canyon Block 608 and transport it to the Typhoon natural gas gathering system in Green Canyon Block 237. We intend to integrate the Marco Polo natural gas gathering system and the Typhoon natural gas gathering system. The oil pipeline will gather oil from the Marco Polo platform into our Allegheny pipeline in Green Canyon Block 164 with a maximum capacity of 120 MBbls/d. These pipelines are expected to be completed and placed in service mid-year 2004, and are expected to cost a total of $106 million to construct. We incurred higher costs than originally anticipated as the result of installation timing conflicts between the Marco Polo TLP installation and the Marco Polo gas pipeline installation and construction down time as the result of weather related delays and strong sea currents. As of December 31, 2003, we have spent approximately $72.7 million on these pipelines, which are in the development stage. Additionally, we received contributions in aid of construction from ANR Pipeline Company and El Paso Field Services, subsidiaries of El Paso Corporation, totaling $17.5 million for benefits of increased volumes they anticipate receiving on their facilities as a result of our construction of the natural gas pipeline. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

Phoenix Gathering System. We are constructing and will own 100 percent of a new $66 million gathering system, to gather natural gas production from the Red Hawk Field located in the Garden Banks area of the Gulf of Mexico. We have entered into related agreements with subsidiaries of Kerr-McGee Corporation and Devon Energy, Inc., which each hold a 50-percent working interest in the Red Hawk Field. Kerr-McGee and Devon have dedicated multiple blocks at and in the proximity of the Red Hawk Field to this pipeline for the life of the reserves, subject to certain release provisions. The 76-mile pipeline, capable of transporting up to approximately 450 MMcf/d of natural gas, will originate in 5,300 feet of water at the Red Hawk platform and connect to the ANR Patterson Offshore Pipeline system at Vermillion Block 397. We plan to place the new pipeline in service mid-year of 2004. As of December 31, 2003, we have spent approximately $51.7 million related to this pipeline, which is in the construction stage. We expect to receive contributions in aid of construction from ANR Pipeline Company, a subsidiary of El Paso Corporation, of $6.1 million, of which $3.0 million has been collected, for the benefits of increased volumes they expect to transport on their pipeline as a result of our construction of this pipeline. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

San Juan Optimization Project. In May 2003, we commenced a $43 million project relating to our San Juan Basin assets. The project is expected to be completed in stages through 2006. The project is expected to result in increased capacity of up to 130 MMcf/d on the San Juan gathering system and increased market opportunities through a new interconnect at the tailgate of our Chaco plant. As of December 31, 2003, we have spent approximately $1.8 million related to this project. We expect to fund the remaining project costs through internally generated funds and borrowings under our credit facility.

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

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

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

We are also considering converting our existing brine well at our propane storage caverns in Hattiesburg to natural gas service. This conversion would cost approximately $16 million and would create a new 1.8 Bcf working natural gas cavern that would be integrated into our Petal storage complex. We are currently negotiating with customers for the full 1.8 Bcf of capacity and expect, subject to final regulatory approval, to have the cavern in service during the fourth quarter of 2004.

General Partner Relationship

In May 2003, GulfTerra Energy Company, L.L.C., a Delaware limited liability company and a wholly owned subsidiary of El Paso Corporation, became our general partner by acquiring our general partner interest from our previous general partner, which was also a wholly owned subsidiary of El Paso Corporation.

Goldman Sachs

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

In December 2003, El Paso Corporation reacquired Goldman Sachs' 9.9 percent interest in our general partner and then sold a 50 percent interest in our general partner to a subsidiary of Enterprise, as discussed earlier. Goldman Sachs no longer owns any interest in our general partner.

Enterprise

In December 2003, a subsidiary of Enterprise purchased a 50 percent interest in our general partner. Enterprise is a leading North American midstream energy company that provides a wide range of services to producers and consumers of natural gas and NGLs. A subsidiary of Enterprise:

- owns 50 percent of our general partner. Enterprise subsidiary's rights are limited to protective consent rights on specified material transactions affecting us or our general partner and the rights and preferences associated with the membership interest in the general partner owned by the Enterprise subsidiary.
- is a customer of ours. However, historically our transactions with Enterprise have been immaterial.

El Paso Corporation

In December 2003, El Paso Corporation sold a 50 percent interest in our general partner to Enterprise. El Paso Corporation, a NYSE-listed company, is a leading provider of natural gas services and the largest pipeline company in North America. Through its subsidiaries, El Paso Corporation:

- owns 50 percent, and is the managing member, of our general partner. Historically, El Paso Corporation and its affiliates have employed the personnel who operate our businesses. We reimburse our general partner and its affiliates for the costs they incur on our behalf under our general and administrative services agreement. The fees we incur for services under this agreement with El Paso Corporation reflect the benefit from El Paso Corporation's ability to utilize their economies of scale to negotiate service levels at favorable costs. We will continue to obtain these services from El Paso Corporation; however; if these services were to end, our expenditures may increase as we may not be able to obtain the same level of services at comparable costs. We also pay our general partner its proportionate share of distributions — relating to its one percent general partnership interest and the related incentive distributions — we make to our partners each calendar quarter.

- is a significant stake-holder in us — as of March 10, 2004, it owns approximately 17.3 percent, or 10,310,045, of our common units (decreased from 26.5 percent as a result of our common unit offerings during 2003, its public sale of 590,000 common units in October 2003 and its sale of 772,400 common units to Goldman Sachs in connection with its December 2003 repurchase of Goldman Sachs' 9.9 percent interest in our general partner), all 10,937,500 of our Series C units, which we issued in November 2002 for $350 million, and 50 percent of our general partner. As holders of some of our common units and all of our Series C units, subsidiaries of El Paso Corporation receive their proportionate share of distributions we make to our partners each calendar quarter. In July 2003, we filed a registration statement on Form S-3 to register for resale 2,000,000 of the common units owned by El Paso Corporation or its subsidiaries. Under this registration statement, an El Paso Corporation subsidiary sold 590,000 of its common units in October 2003.
- is a customer of ours. As we have with other large energy companies, we have entered into a number of contracts with El Paso Corporation and its affiliates.

Exchange Transactions With El Paso Corporation

In connection with our November 2002 San Juan assets acquisition, El Paso Corporation retained the obligation to repurchase the Chaco plant from us for $77 million in October 2021. In October 2003, we released El Paso Corporation from that obligation and El Paso Corporation contributed specified communications assets and other rights to us. The communications assets we received are used in the operation of our pipeline systems.

As a result of the October 2003 exchange, we revised our estimate for the depreciable life of the Chaco Plant from 19 to 30 years, the estimated remaining useful life of the Chaco plant. Depreciation expense will decrease approximately $0.5 million and $2.3 million on a quarter and annual basis.

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

In accordance with our procedures for evaluating and valuing material transactions with El Paso Corporation, our general partner's Audit and Conflicts Committee engaged an independent financial advisor to provide a fairness opinion related to transactions with Goldman Sachs, except for the purchase from El Paso Corporation of the 9.9 percent general partner interest, the asset exchange with El Paso Corporation, and the redemption of Series B Preference Units. Based on this opinion, the Audit and Conflicts Committee and the full board of directors approved these transactions taken as a whole.

Other

We have continued to improve our corporate governance model, which we believe currently meets the standards established by the Securities and Exchange Commission (SEC) and NYSE. During the first quarter of 2003, we identified and evaluated a number of changes that could be made to our corporate structure to better address potential conflicts of interest and to better balance the risks and rewards of significant relationships with our affiliates, which we refer to as Independence Initiatives. During 2003, we were largely successful in implementing these initiatives, as well as implementing what we believed to be the best practices in corporate governance. We added an additional independent director to our board of directors, bringing the number of independent directors to four of the six-member board. Further, we established a governance and compensation committee of our board of directors, consisting solely of independent directors, which is responsible for establishing performance measures and making recommendations to El Paso Corporation concerning compensation of its employees performing duties for us. Finally, our general partner received third party investments (first from Goldman Sachs and then from Enterprise), which made our general partner's decision making process more independent from El Paso Corporation.

Liquidity and Capital Resources

Our principal requirements for cash, other than our routine operating costs, are for capital expenditures, debt service, business acquisitions and distributions to our partners. We plan to fund our short-term cash needs, including operating costs, maintenance capital expenditures and cash distributions to our partners, from cash generated from our operating activities and borrowings under our credit facility. Capital expenditures we expect to benefit us over longer time periods, including our organic growth projects and business acquisitions, we plan to fund through a variety of sources (either separately or in combination), which include issuing additional common units, borrowing under commercial bank credit facilities, issuing public or private placement debt and other financing transactions. We plan to fund our debt service requirements through a combination of refinancing arrangements and cash generated from our operating activities. Our merger agreement with Enterprise limits our ability to raise additional capital prior to the closing of the merger without Enterprise's approval; however, we believe that these limitations will not affect our liquidity.

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

Capital Resources

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

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

(1) Offering includes 80 Series F convertible units, which are described below.

In addition to our public offerings of common units, in October 2003 we sold 3,000,000 common units privately to Goldman Sachs in connection with their purchase of a 9.9 percent membership interest in our general partner. We used the net proceeds of $111.5 million from that private sale to temporarily reduce indebtedness under our revolving credit facility and, in December 2003, to redeem a portion of our outstanding senior subordinated notes. See below in this section under "Indebtedness and Other Obligations," for a discussion of the redemption of a portion of our senior subordinated notes.

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

Series B Preference Units

In August 2000, we issued 170,000 Series B preference units with a value of $170 million to acquire the Petal and Hattiesburg natural gas storage businesses from a subsidiary of El Paso Corporation. In October 2001, we redeemed 44,608 of the Series B preference units for a $50 million liquidation value, including accrued distributions of approximately $5.4 million. In connection with our 2003 public offerings of common units through September 30, 2003, our general partner, in lieu of a cash contribution, contributed to us, and we retired, 1,527 Series B preference units with liquidation value of approximately $2.0 million, including accrued distributions of approximately $0.5 million, to maintain its one percent general partner interest. In October 2003, we redeemed all of our remaining outstanding Series B preference units.

Series C Units

In connection with our acquisition of the San Juan assets in November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of our Series C units, a new class of our limited partner interests, at a price of $32 per unit, $350 million in the aggregate. The Series C units are similar to our existing common units, except that the Series C units are non-voting limited partnership interests. After April 30, 2003, the holder of Series C units has the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit will convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C unit will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate will increase on April 30, 2004 to 110 percent of the common unit distribution rate and on April 30, 2005 to 115 percent of the common unit distribution rate. The holder of the Series C units has thus far not requested a vote to convert the Series C units into common units. As part of the proposed merger with Enterprise, in the second transaction, which will occur immediately prior to the merger, Enterprise will purchase from a subsidiary of El Paso Corporation all of our outstanding Series C units. These units will not be converted to Enterprise common units in the merger but rather will remain limited partnership interests in GulfTerra after the merger and, as such interest, will lose their GulfTerra common unit conversion and distribution rights.

Series F Convertible Units

In connection with our public offering of 1,118,881 common units in May 2003, we issued 80 Series F convertible units. Each Series F convertible unit is comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that have identical terms except for vesting and termination times and the number of underlying common units into which they may be converted. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until the date we merge with Enterprise (subject to other defined extension rights). The Series F2 units are convertible into up to $40 million of common units. The Series F2 units terminate on March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units equal to the lesser (i) of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75, or (ii) the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units; (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units assuming we had received a conversion notice on December 31, 2003 and March 2, 2004, was $40.38 and $39.40. The Series F units may be converted into a maximum of 8,329,679 common units. Holders of Series F convertible units are not entitled to vote or receive distributions. The $4.1 million value associated with the Series F convertible units is included in partners' capital as a component of common units capital.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26.00 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at December 31, 2003.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million.

Any Series F convertible units outstanding at the merger date will be converted into rights to receive Enterprise common units, subject to the restrictions governing the Series F units. The number of Enterprise common units and the price per unit at conversion will be adjusted based on the 1.81 exchange ratio.

Indebtedness and Other Obligations

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

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

In July 2003, Cameron Highway Oil Pipeline Company, our 50 percent owned joint venture that is constructing the 390-mile Cameron Highway Oil Pipeline, entered into a $325 million project loan facility consisting of a $225 million construction loan and $100 million of senior secured notes. At December 31, 2003, Cameron Highway had $69 million outstanding under the construction loan and $56 million of senior secured notes outstanding.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under Statement of Financial Accounting Standards (SFAS) No. 133. At December 31, 2003, the fair value of the swap was a liability, included in non-current liabilities, of approximately $7.4 million. The fair value of the hedged debt decreased by the same amount.

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

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

In December 2003, we exercised our right, under the terms of our senior subordinated notes' indentures, to repay, at a premium, approximately $269.4 million in principal amounts of those senior subordinated notes. The indentures provide that, within 90 days of an equity offering, we can call up to 33 percent of the original face amount at a premium. The amount we can repay is limited to the net proceeds of the offering. We recognized additional costs totaling $29.1 million resulting from the payment of the redemption premiums and the write-off of unamortized debt issuance costs, premiums and discounts. We accounted for these costs as an expense during the fourth quarter of 2003 in accordance with the provisions of SFAS No. 145. In March 2004, we gave notice to exercise our right, under the terms of our senior subordinated notes' indentures, to repay, at a premium, approximately $39.1 million in principal amount of those senior subordinated notes. The indentures provide that, within 90 days of an equity offering, we can call up to 33 percent of the original face amount at a premium. The amount we can repay is limited to the net proceeds of the offering. We will recognize additional costs totaling $4.1 million resulting from the payment of the redemption premiums and the writeoff of unamortized debt issuance costs. We will account for these costs as an expense during the second quarter of 2004 in accordance with the provisions of SFAS No. 145.

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

The following table presents the timing and amounts of our debt repayment and other obligations for the years following December 31, 2003, that we believe could affect our liquidity (in millions):

Debt Repayment and Other Obligations	<1 Year	1-3 Years	3-5 Years	After 5 Years	Total
Revolving credit facility	$—	$382	$ —	$ —	$ 382
Senior secured term loan	3	6	291	—	300
6¼% senior notes issued July 2003, due June 2010	—	—	—	250	250
10⅜% senior subordinated notes issued May 1999, due June 2009	—	—	—	175	175
8½% senior subordinated notes issued March 2003, due June 2010	—	—	—	255	255
8½% senior subordinated notes issued May 2001, due 2011	—	—	—	168	168
8½% senior subordinated notes issued May 2002, due June 2011	—	—	—	154	154
10⅝% senior subordinated notes issued November 2002, due December 2012	—	—	—	134	134
Wilson natural gas storage facility operating lease	5	10	8	—	23
Texas leased NGL storage facilities	2	4	1	2	9
Total debt repayment and other obligations	$10	$402	$300	$1,138	$1,850

Capital Expenditures

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our operating and growth objectives. These estimates may change due to factors beyond our control, such as weather-related issues, changes in supplier prices or poor economic conditions. Further, estimates may change as a result of decisions made at a later date, which may include acquisitions, scope changes or decisions to take on additional partners. Our projection of expenditures for the quarters ended December 31, September 30, June 30 and March 31, 2003 as presented in our 2002 Annual Report on Form 10-K were $55, $78, $92 and $120 million; however, our actual expenditures were approximately $86, $39, $125 and $80 million.

The tables below depict our estimate of projects and capital maintenance expenditures through December 31, 2004. These estimates are net of anticipated contributions in aid of construction and contributions from joint venture partners. We expect to be able to fund these forecasted expenditures from a combination of operating cash flow and funds available under our revolving credit facility and other financing arrangements. Actual results may vary from these projections.

Forecasted Expenditures

	Quarters Ending				Net Total Forecasted Expenditures
	March 31, 2004	June 30, 2004	September 30, 2004	December 31, 2004	
			(In millions)		
Net Forecasted Capital Project Expenditures	$ 47	$ 31	$ 5	$ 9	$ 92
Other Forecasted Capital Expenditures	15	10	10	5	40
Additional Capital Contributions to Our Unconsolidated Affiliates	14	—	8	—	22
Total Forecasted Expenditures	$ 76	$ 41	$ 23	$ 14	$ 154

Construction Projects

	Capital Expenditures				Capacity		
	Forecasted		As of December 31, 2003				
	Total[(1)]	GulfTerra[(2)]	Total[(1)]	GulfTerra[(2)]	Oil	Natural Gas	Expected In-Service
	(In millions)				(MBbls/d)	(MMcf/d)	
Wholly owned projects							
Marco Polo Natural Gas and Oil Pipelines	$106	$89	$ 73	$56	120	400	Mid-Year 2004
Phoenix Gathering System	66	60	52	49	—	450	Mid-Year 2004
Joint venture projects							
Marco Polo Tension Leg Platform[(3)]	232	45	225	33	120	300	Second Quarter 2004
Cameron Highway Oil Pipeline[(4)]	458	85	256	85	500	—	Fourth Quarter 2004

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

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

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

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

Under the merger agreement with Enterprise, we can not make capital expenditures, without Enterprise's consent, in excess of $5 million or $25 million in the aggregate other than (1) as required on an emergency basis and (2) those planned expenditures previously disclosed to Enterprise. The forecasted expenditures disclosed in the tables above were either planned expenditures previously disclosed to Enterprise or fall within the monetary thresholds in the merger agreement.

Cash from Operating Activities

Net cash provided by operating activities was $268.2 million for the year ended December 31, 2003, compared to $176.0 million for the same period in 2002. The increase was primarily attributable to operating cash flows generated by our acquisitions of the EPN Holding assets in April 2002 and the San Juan assets in November 2002. This increase was partially offset by lower cash distributions in 2003 from Poseidon.

Cash from Investing Activities

Net cash used in investing activities was approximately $287.2 million for the year ended December 31, 2003. Our investing activities include capital expenditures related to the construction of the Marco Polo pipelines, the Cameron Highway oil pipeline and the Falcon Nest fixed-leg platform. These expenditures were partially offset by proceeds of $69.8 million from the sale of a 50 percent interest in Cameron Highway to Valero and $8.1 million from the sale and retirement of other assets.

Cash from Financing Activities

Net cash provided by financing activities was approximately $13.4 million for the year ended December 31, 2003. During 2003, our cash provided by financing activities included the issuances of long-term debt and offerings of common units and convertible units. Cash used in our financing activities included repayments on our senior secured acquisition term loan long-term debt, our revolving credit facility and other financing obligations, as well as distributions to our partners.

Results of Operations

Our business activities are segregated into four distinct operating segments:

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

Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. For a further discussion of the individual segments, see Part II, Item 8, Financial Statements and Supplementary Data, Note 15. For the past three years, inflation has not had a material effect on any of our financial results.

Segment Results

We use performance cash flows (which we formerly referred to as EBITDA) to evaluate the performance of our segments, determine how resources will be allocated and develop strategic plans. We define performance cash flows as earnings before interest, income taxes, depreciation and amortization and other adjustments. Historically our lenders and equity investors have viewed our performance cash flows measure as an indication of our ability to generate sufficient cash to meet debt obligations or to pay distributions. We believe that there has been a shift in investors' evaluation regarding investments in MLPs and they now put as much focus on the performance of an MLP investment as they do its ability to pay distributions. For that reason, we disclose performance cash flows as a measure of our segment's performance. A reconciliation of this measure to net income for our consolidated results is as follows:

	Years Ended December 31,		
	2003	2002	2001
Natural gas pipelines and plants	$311,164	$167,185	$ 52,200
Oil and NGL logistics	59,053	43,347	47,560
Natural gas storage	29,554	16,629	13,209
Platform services	20,181	29,224	30,783
Segment performance cash flows	419,952	256,385	143,752
Plus: Other, nonsegment results	15,107	10,427	17,688
Earnings from unconsolidated affiliates	11,373	13,639	8,449
Income from discontinued operations	—	5,136	1,097
Cumulative effect of accounting change	1,690	—	—
Noncash hedge gain	—	411	—
Noncash earnings related to future payments from El Paso Corporation	—	—	25,404
Less: Interest and debt expense	127,830	81,060	41,542
Loss due to early redemptions of debt	36,846	2,434	—
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	—	—	3,921
Cash distributions from unconsolidated affiliates	12,140	17,804	35,062
Minority interest	917	(60)	100
Net cash payment received from El Paso Corporation	8,404	7,745	7,426
Discontinued operations of Prince facilities	—	7,201	6,561
Loss on sale of Gulf of Mexico assets	—	—	11,851
Net income	$163,139	$ 97,688	$ 55,149

Natural Gas Pipelines and Plants

The Natural gas pipelines and plants segment includes the San Juan gathering system and related assets, the Permian Basin System, the Texas Intrastate system, the GulfTerra Alabama Intrastate system, the Viosca Knoll Gathering System, the HIOS System, the East Breaks System, the Falcon Gas Pipeline, the Typhoon Gas Pipeline, the Chaco cryogenic natural gas processing plant and the Indian Basin processing and treating facility. The natural gas gathering and transportation pipelines and related assets which receive natural gas from producing properties in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and the Gulf of Mexico, primarily earn revenue from fixed-fee-based services or market-based rates that are usually related to the monthly natural gas price index for volume gathered. Offshore pipelines often involve life-of-reserve commitments with both firm and interruptible components, whereas onshore pipelines generally have contracts for a specific number of years or are month to month. The Chaco plant receives and processes natural gas from the San Juan Basin. The Indian Basin facility receives and processes natural gas from the Permian Basin. GulfTerra Alabama Intrastate 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.

In our natural gas pipelines and plants segment, we utilize derivative financial instruments to manage a portion of our exposure to movements in commodity prices. For a further discussion, see Part II, Item 8, Financial Statements and Supplementary Data, Note 12.

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

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Natural gas pipelines and plants revenues	$ 734,797	$ 357,808	$101,064
Cost of natural gas and other products	(286,456)	(108,819)	(51,542)
Natural gas pipelines and plants margin	448,341	248,989	49,522
Operating expenses excluding depreciation, depletion, and amortization	(141,039)	(82,942)	(10,874)
Other income and cash distributions from unconsolidated affiliates in excess of earnings[1]	3,843	1,609	13,504
Noncash hedge gain	—	(411)	—
Minority interest	19	(60)	48
Performance cash flows	$ 311,164	$ 167,185	$ 52,200
Volumes (Gross MDth/d)			
Texas Intrastate[2]	3,331	2,484	—
San Juan Gathering[3]	1,227	120	—
Permian Basin gathering[2]	320	261	22
Viosca Knoll Gathering	670	565	551
HIOS	708	740	979
Falcon Nest pipeline[4]	148	—	—
Other natural gas pipelines[3]	487	399	416
Processing plants[3]	794	733	133
Gulf of Mexico assets sold	—	—	243
Total natural gas volumes	7,685	5,302	2,344

(1) Earnings (loss) from unconsolidated affiliates for the years ended December 31, 2003, 2002, and 2001, was $2,377 thousand, $194 thousand and ($9,761) thousand.

(2) We purchased the Texas Intrastate assets, and the Carlsbad and Waha systems, which are included in the Permian Basin gathering systems, in April 2002.

(3) We purchased the San Juan gathering system, the remaining interest in the Chaco processing plant and the Typhoon natural gas pipeline in November 2002.

(4) The Falcon Nest pipeline was placed in service in March 2003.

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

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast region (and these assets) in late September and early October of 2002. As of December 31, 2003, we had recorded fuel differences of approximately $8.2 million, which is included in other non-current assets. We are currently in discussions with the FERC as well as our customers regarding the potential collection of some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers will negatively impact the future results of our natural gas pipelines and plants segment.

Year Ended 2003 Compared to Year Ended 2002

Natural gas pipelines and plants margin for the year ended December 31, 2003 was $199.4 million higher than in 2002, primarily attributed to these asset acquisition:

	(In millions)
EPN Holding assets (April 2002)	$ 36.7
San Juan gathering and remaining Chaco interest (November 2002)	156.7
Total	$193.4

Margin also increased by $4.4 million due to an increase in volumes on our Falcon Nest Pipeline, which was placed in service in March 2003, and $3.8 million due to additional volumes on our Viosca Knoll system from the Canyon Express pipeline system and from the Medusa and Matterhorn natural gas pipelines, which were placed in service during the latter part of the fourth quarter of 2003. Additionally, margin increased due to higher NGL prices in 2003, which increased our processing margins at the Chaco facility by $2.0 million and at the Indian Basin gas plant by $4.5 million. Partially offsetting these increases was a $3.0 million decrease in margin for our Texas intrastate pipeline system attributable to the impact that higher natural gas prices in 2003 had on our fuel costs and the revaluation of our natural gas imbalances. The increases were also offset by an additional $3.3 million decrease in margin related to lower volumes on our HIOS pipeline due to natural decline in the western region of the Gulf of Mexico.

Operating expenses excluding depreciation, depletion, and amortization for the year ended December 31 2003, was $58.1 million higher than the same period in 2002 primarily due to the acquisition of the San Juan and EPN Holding assets. Excluding the operating costs of these acquired assets, operating expenses increased by $9.8 million primarily due to higher repair and maintenance expenses of $7.3 million, of which $6.0 million relates to expenditures on our Texas intrastate pipeline, which were unusually low in 2002 due to timing of expenditures, and $1.3 million attributable to repairs on our Viosca Knoll gas pipeline extension, which was damaged by a ship anchor after construction. Further contributing to the increase was higher expenses associated with an increase in our allowance for doubtful accounts of $1.5 million in 2003.

Other income and cash distributions from unconsolidated affiliates in excess of earnings for the year ended December 31, 2003, primarily relates to earnings from our unconsolidated affiliate, Coyote Gas Treating, L.L.C., which we acquired in connection with the San Juan asset acquisition in November 2002.

The noncash hedge gain for the year ended December 31, 2002, is related to our San Juan hedging activity prior to our acquisition of the San Juan assets in November 2002. Prior to this acquisition we accounted for this activity under mark-to-market accounting since it did not qualify for hedge accounting under SFAS No. 133.

Year Ended 2002 Compared to Year Ended 2001

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

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

The margin on the assets we owned for the full years in 2001 and 2002 decreased by $1.1 million in 2002 primarily as a result of a $0.6 million decrease due to Hurricane Isidore in September 2002 and Hurricane Lili in October 2002.

Operating expenses excluding depreciation, depletion and amortization for the year ended December 31, 2002 were $72.1 million higher than the same period in 2001 including $28.2 million related to our April 2002 purchase of the EPN Holding assets, $4.5 million related to our purchase of the Chaco plant, $12.1 million related to our consolidation of Deepwater Holdings and $1.9 million related to the purchase of the San Juan assets in November 2002. Excluding the operating costs of the newly acquired assets, other operating expenses increased by $2.3 million primarily due to an increase in GulfTerra Alabama Intrastate's operating fee of $1.2 million and an increase in gas imbalance costs on our Viosca Knoll system of $1.0 million.

Other income (expenses) and cash distributions from unconsolidated affiliates in excess of earnings for the year ended December 31, 2002, was $11.9 million lower than the same period in 2001 primarily due to our consolidation of Deepwater Holdings in October 2001.

Oil and NGL Logistics

The Oil and NGL logistics segment includes the Poseidon, Allegheny and Typhoon offshore oil pipelines, the Texas NGL transportation pipelines and fractionation plants, the Almeda fractionator and other Texas NGL assets. 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. The Texas plants fractionate NGLs into ethane, propane, butane and natural gasoline products which are used by refineries and petrochemical plants along the Texas Gulf Coast. We receive a fixed fee for each barrel of NGL transported and fractionated by the Texas facilities from a subsidiary of El Paso Corporation. We have dedicated 100 percent of our Texas fractionation facilities' capacity to this subsidiary of El Paso Corporation.

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

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Oil and NGL logistics revenues	$ 53,850	$ 37,645	$ 32,327
Cost of natural gas and other products	(524)	—	—
Oil and NGL logistics margin	53,326	37,645	32,327
Operating expenses excluding depreciation, depletion and amortization and gain from sale of Cameron Highway	(21,918)	(10,105)	(6,979)
Gain on sale of long-lived assets[4]	19,000	—	—
Other income and cash distributions from unconsolidated affiliates in excess of earnings[1]	8,645	15,807	22,212
Performance cash flows	$ 59,053	$ 43,347	$ 47,560
Liquid volumes (Bbls/d)			
Allegheny Oil Pipeline	16,685	17,570	12,985
Typhoon Oil Pipeline[2]	28,238	1,211	—
Unconsolidated affiliate Poseidon Oil Pipeline[3]	127,214	135,652	155,453
NGL Fractionation Plants	59,337	70,737	63,212
NGL Pipeline Systems	29,366	1,183	—
Total liquid volumes	260,840	226,353	231,650

(1) Earnings from unconsolidated affiliates for the years ended December 31, 2003, 2002, and 2001, was $8,098, $13,445 and $18,210.

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

(3) Represents 100 percent of Poseidon volumes.

(4) Represents a gain of $19 million associated with the sale of our 50 percent interest in Cameron Highway to Valero Energy Corporation in July 2003. Refer to previous discussion regarding Cameron Highway Oil Pipeline Company under Capital Expenditures in this Item 7.

The majority of the earnings from the Oil and NGL logistics segment are generated from volume-based fees for providing transportation of oil and NGLs and fractionation of NGLs. However, many of the agreements with the customers on our oil pipelines require that we purchase oil from the customer at the inlet of our pipeline for an index price, less an amount that compensates us for transportation services, and resell the oil to the customer at the outlet of our pipeline at the same index price. We record these transactions based on the net amount billed to our customers resulting in these transactions reflecting a fee for transportation services.

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

Year Ended 2003 Compared to Year Ended 2002

For the year ended December 31, 2003, margin was $15.7 million higher than the same period in 2002. Our acquisition in November 2002 of the NGL pipeline systems and Typhoon Oil Pipeline contributed approximately $17.3 million and $2.3 million to the increase. Partially offsetting this increase was a $4.1 million decrease in margin at our NGL plants due to lower volumes resulting from poor processing economics.

Operating expenses excluding depreciation, depletion and amortization for the year ended December 31, 2003 were $11.8 million higher than the same period in 2002, primarily due to increased operating expenses of $9.7 million related to our November 2002 acquisition of the Typhoon Oil pipeline and the NGL pipeline systems. Excluding assets purchased, our operating expenses excluding depreciation, depletion and amortization were $2.1 million higher primarily due to increased operating expenses related to well testing on the Anse La Butte NGL Storage facility and the Hattiesburg NGL Storage facility.

Other income and cash distributions from unconsolidated affiliates in excess of earnings for the year ended December 31, 2003, were $5.3 million and $1.8 million lower than the same period in 2002. Poseidon experienced lower earnings due to natural production declines on some of the older deepwater fields, as well as production downtime at several new fields. In addition, in October 2003, Poseidon began withholding distributions to fund its capital expenditures related to its Front Runner project. As a result we received lower cash distributions than in the same period in 2002.

Year Ended 2002 Compared to Year Ended 2001

Margin for the year ended December 31, 2002, was $5.3 million higher than the same period in 2001. Our acquisitions of the NGL fractionation plants in February 2001, the Hattiesburg propane storage facility in January 2002, and the Anse La Butte NGL storage facility in December 2001 contributed approximately $0.6 million, $1.2 million and $1.6 million to the increase. Additionally, in November 2002, we purchased the NGL pipeline systems and the Typhoon Oil pipeline, and these assets contributed $0.1 million and $0.5 million to the increase. Excluding assets purchased, our margin was $1.2 million higher primarily as a result of higher volumes on Allegheny.

Operating expenses excluding depreciation, depletion, and amortization for the year ended December 31, 2002, were $3.1 million higher than the same period in 2001 primarily due to increased operating expenses of $2.1 million related to our acquisitions of the NGL fractionation plants in February 2001, the Hattiesburg propane storage facility in January 2002, the Anse La Butte NGL storage facility in December 2001, the Typhoon Oil Pipeline and NGL pipeline systems in November 2002. Excluding assets purchased, our operating expenses excluding depreciation, depletion and amortization were $1.0 million lower as a result of modifying the operating agreement in connection with the EPN Holding acquisition in April 2002 between our NGL fractionation plants and El Paso Field Services.

Other income and cash distributions from unconsolidated subsidiaries in excess of earnings for the year ended December 31, 2002, declined $4.8 million and $1.6 million from the 2001 period. These declines are due to decreases in earnings from unconsolidated affiliates of $4.8 million as a result of lower volumes on the Poseidon Oil Pipeline partially attributable to Hurricane Isidore in September 2002 and Hurricane Lili in October 2002. Offsetting volume decreases were additional volumes generated from new contracts entered into by Poseidon Oil Pipeline. These contracts began in November 2002 and December 2002 and had a six month duration. We realized our 36 percent share of the volume increase through earnings from unconsolidated affiliates.

Natural Gas Storage

The Natural gas storage segment includes the Petal and Hattiesburg storage facilities and related pipeline, which were acquired in August 2000, and a leased interest in the Wilson natural gas storage facility, located in Wharton County, Texas, which we acquired in April 2002. The Petal and Hattiesburg storage facilities serve the Northeast, Mid-Atlantic and Southeast natural gas markets. In June 2002, we completed a 8.9 Bcf (6.3 Bcf working capacity) expansion of our Petal facility.

For the periods included in the following table, the revenues from these facilities consist primarily of fixed reservation fees for natural gas storage capacity. Natural gas storage capacity revenues are recognized and due during the month in which capacity is reserved by the customer, regardless of the capacity actually used. We also receive fees for injections and withdrawals by our customers and interruptible storage fees. The following table presents performance cash flows derived from our Natural gas storage segment:

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Natural gas storage revenue	$ 44,575	$ 28,602	$19,373
Cost of natural gas	(2,506)	—	—
Natural gas storage margin	42,069	28,602	19,373
Operating expenses excluding depreciation, depletion and amortization	(12,517)	(11,973)	(6,184)
Other income and cash distributions from unconsolidated affiliates in excess of (less than) earnings(1)	(896)	—	20
Minority interest	898	—	—
Performance cash flows	$ 29,554	$ 16,629	$13,209
Storage volumes			
Year end working gas capacity (Bcf)	13.5	13.5	7.5
Firm storage (Bcf)			
Average working gas capacity available	13.5	10.4	7.5
Average firm subscription	12.7	9.7	6.9
Average monthly commodity volumes(2)	3.9	3.9	1.9
Interruptible storage (Bcf)			
Contracted volumes	0.3	0.2	0.4
Average monthly commodity volumes(2)	0.5	1.0	1.6

(1) The amount in 2003 represents our gain on the sale of Copper Eagle to El Paso Natural Gas Company in excess of cash distributions we received.

(2) Combined injections and withdrawals volumes.

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

Year Ended 2003 Compared to Year Ended 2002

For the year ended December 31, 2003, margin was $13.5 million higher than the same period in 2002. An increase in subscribed firm storage capacity attributable to the expansion of the Petal storage facility, which was completed in June 2002, and our acquisition of the Wilson storage facility lease in April 2002, accounted for approximately $12.1 million and $1.6 million of the increase.

Year Ended 2002 Compared to Year Ended 2001

Natural gas storage margin for the year ended December 31, 2002, was $9.2 million higher than the same period in 2001. The expansion of our Petal storage facility and our acquisition of the Wilson storage facility lease in April 2002 accounted for approximately $7.2 million and $4.3 million of the increase. Excluding the increase in margin from the Petal expansion and our acquisition of the Wilson storage facility lease, margin was down $2.3 million primarily as a result of a decrease in interruptible storage services.

Operating expenses excluding depreciation, depletion and amortization for the year ended December 31, 2002, were $5.8 million higher than the same period in 2001 including $0.6 million related to the expansion of our Petal storage facility in the second quarter of 2002, $4.7 million related to the acquisition of the Wilson storage facility lease in April 2002 and $0.6 million related to a favorable resolution of an imbalance settlement in 2001.

Platform Services

The Platform services segment consists of the Falcon Nest, East Cameron 373, Viosca Knoll 817, Garden Banks 72, Ship Shoal 331, and Ship Shoal 332 platforms. These offshore platforms are primarily 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. As part of our acquisition of the EPN Holding assets from subsidiaries of El Paso Corporation in April 2002, we sold the Prince TLP to a subsidiary of El Paso Corporation. The following table presents performance cash flows derived from our Platform services segment and volumes associated with each platform.

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Platform services revenue from external customers	$20,861	$16,672	$15,385
Platform services intersegment revenue	2,603	9,283	12,620
Operating expenses excluding deprecation, depletion, and amortization	(3,283)	(3,001)	(3,097)
Other income (loss)	—	114	(14)
Discontinued operations of Prince facilities	—	6,156	5,889
Performance cash flows	$20,181	$29,224	$30,783
Natural gas platform volumes (MDth/d)			
East Cameron 373	108	130	170
Viosca Knoll 817	5	8	12
Garden Banks 72	15	13	7
Falcon Nest Platform	143	—	—
Total natural gas platform volumes	271	151	189
Oil platform volumes (Bbl/d)			
East Cameron 373	978	1,602	1,927
Viosca Knoll 817	2,059	2,064	2,049
Garden Banks 72	1,018	1,070	1,487
Falcon Nest Platform	546	—	—
Total oil platform volumes	4,601	4,736	5,463

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

Year Ended 2003 Compared to Year Ended 2002

For the year ended December 31, 2003, revenues from external customers were $4.2 million higher than in the same period in 2002 of which $9.9 million is attributable to the Falcon Nest fixed leg platform that went into operation in March 2003. Partially offsetting this increase were lower revenues of $5.3 million from East Cameron 373 resulting from one time billing adjustments in 2002 for fixed monthly platform access fees, a gas dehydration fee, decreased demand fees and lower production. Intersegment revenues were $6.7 million lower due to the expiration in June 2002 and December 2002 of the fixed fee portion of the Viosca Knoll 817 and Garden Banks 72 platform access fee contracts with one of our wholly owned subsidiaries.

Year Ended 2002 Compared to Year Ended 2001

Platform services revenue from external customers for the year ended December 31, 2002, was $1.3 million higher than in the same period in 2001 primarily due to one-time billing adjustments for fixed monthly platform access fees and a gas dehydration fee contract on the East Cameron 373 platform.

Platform services intersegment revenue for the year ended December 31, 2002 was $3.3 million lower than the same period in 2001 primarily due to the expiration in June 2002 of the fixed fee portion of the Viosca Knoll 817 platform access fee contract with one of our wholly owned subsidiaries.

Other, Non-Segment Results

Our oil and natural gas production interests in the Garden Banks 72, Garden Banks 117, Viosca Knoll 817 and West Delta 35 Blocks principally comprise the non-segment activity. Production from these properties is gathered, transported, and processed through our pipeline systems and platform facilities. Oil and natural gas production volumes are produced and sold to various third parties and subsidiaries of El Paso Corporation, at the market price. Revenue is recognized in the period of production. These revenues may be impacted by market changes, hedging activities, and natural declines in production reserves. We are reducing our oil and natural gas production activities by not acquiring additional properties due to their higher risk profile. Accordingly, our focus is to maximize the production from our existing portfolio of oil and natural gas properties.

Also included in other, non-segment results are the quarterly payments we receive from El Paso Corporation in connection with the sale of our Gulf of Mexico assets in January 2001. El Paso Corporation agreed to pay us $2.25 million per quarter through the fourth quarter of 2003 and $2 million in the first quarter of 2004, after which these payments will cease.

Year Ended 2003 Compared to Year Ended 2002

Performance cash flows related to non-segment activity for the year ended December 31, 2003, was $5.2 million higher than the same period in 2002 due to lower demand fee expense of $6.7 million resulting from the expiration of the fixed fee portion of the Viosca Knoll 817 contract in June 2002 and the Garden Banks 72 contract in December 2002. Performance cash flows related to non-segment activity also increased by $5.7 million due to higher oil and natural gas prices in 2003. Partially offsetting these increases were lower production from the Garden Banks 117 and Viosca Knoll 817 fields of $2.4 million and higher operating expenses of $4.2 million associated with an increase in professional fees, including legal, accounting and consulting services.

Year Ended 2002 Compared to Year Ended 2001

Performance cash flows related to non-segment activity for the year ended December 31, 2002, was $7.2 million lower than in the same period in 2001. The decrease was primarily due to lower natural gas and oil prices through most of 2002, as well as lower volumes attributable to a decrease in production as a result of normal decline of existing reserves which resulted in decreased revenues of $2.2 million. Further contributing to the decrease was lower interest income of $1.3 million on the additional consideration from El Paso Corporation related to the sale of the Gulf of Mexico assets as well as lower revenue of $0.4 million due to Hurricane Isidore in September 2002 and Hurricane Lili in October 2002.

Depreciation, Depletion, and Amortization

Year Ended 2003 Compared to Year Ended 2002

Depreciation, depletion and amortization for the year ended December 31, 2003 was $26.7 million higher than the same period in 2002 primarily due to the following:

Purchase of the San Juan assets in November 2002	$ 20.4
Purchase of the EPN Holding assets in April 2002	5.3
Completion of the Petal expansion in July 2002	3.0
Falcon Nest pipeline and platform, which went into operation in March 2003	1.3
Decrease in depletion resulting from lower oil and natural gas production	(4.2)
Other	0.9
	$ 26.7

Year Ended 2002 Compared to Year Ended 2001

Depreciation, depletion and amortization for the year ended December 31, 2002 was $37.3 million higher than the same period in 2001 primarily due to the following:

Purchase of the EPN Holding assets in April 2002	$15.5
Consolidation of Deepwater Holdings in October 2001	8.5
Purchase of the Chaco plant in October 2001	6.5
Completion of the Petal expansion in July 2002	2.9
Purchase of the San Juan assets in November 2002	2.3
GTM Texas fractionation facilities acquired in February 2001	0.8
Other	0.8
	$37.3

Interest and Debt Expense

Year Ended 2003 Compared to Year Ended 2002

Interest and debt expense, net of capitalized interest, for the year ended December 31, 2003, was approximately $46.7 million higher than the same period in 2002. This increase is primarily due to a higher outstanding balance on our revolving credit facility and long-term debt and interest incurred on the following indebtedness:

- our $230 million 8½% senior subordinated notes that we issued in May 2002 and used to repay a portion of the GulfTerra Holding term credit facility;
- our $160 million senior secured term loan that we entered into in October 2002 and refinanced in December 2003 to, among other things, expand the existing term component from $160 million to $300 million;
- our $200 million 10⅝% senior subordinated notes that we issued and our $237.5 million senior secured acquisition term loan we entered into in November 2002 in connection with our acquisition of the San Juan assets; and
- our $300 million 8½% senior subordinated notes that we issued in March 2003 and used to repay our $237.5 million senior secured acquisition term loan.

In December 2003, we redeemed approximately $269.4 million in principal amount of our senior subordinated notes, see Part II, Item 8, Financial Statements and Supplementary Data, Note 6.

Capitalized interest for the year ended December 31, 2003 was $12.5 million, representing an increase of $6.9 million for the year ended December 31, 2002. The increase is the result of an increase in construction work-in-process as a result of increased expenditures related to our construction projects.

Year Ended 2002 Compared to Year Ended 2001

Interest and debt expense related to continuing operations, net of capitalized interest, for the year ended December 31, 2002, was approximately $39.5 million higher than the same period in 2001. This increase is primarily due to an increase in the average outstanding balance of our revolving credit facility, the amounts outstanding under the EPN Holding term credit facility which we entered to purchase the EPN Holding assets in April 2002, and the $230 million 8½% senior subordinated notes issued in May 2002. Additionally, interest expense increased by approximately $5.2 million as a result of additional indebtedness we incurred in the fourth quarter of 2002 (see Item 8, Financial Statements and Supplementary Data, Note 6) in connection with our San Juan assets acquisition including additional interest expense associated with amending our credit facility and the EPN Holding term credit facility. Capitalized interest for the year ended December 31, 2002 was $5.6 million compared to $11.8 million for the same period in 2001.

Losses Due to Early Redemptions of Debt and Write-off of Debt Issuance Costs

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

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

In December 2003, we refinanced the term loan portion of our credit facility. We charged $2.8 million to expense in December 2003 to recognize the unamortized debt issuance costs associated with the initial term loan.

In December 2003, we redeemed approximately $269.4 million in principal amount of our senior subordinated notes and recognized a loss of $29.1 million resulting from the payment of the redemption premiums and the write-off of unamortized debt issuance costs, premiums and discounts.

In December 2002, we retired a portion of our GTM Holding term credit facility and recognized a loss of $2.4 million related to the write-off of unamortized debt issuance costs associated with this facility.

Commitments and Contingencies

See Part II, Item 8, Financial Statements and Supplementary Data, Note 11, 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 decisions 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 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. 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. Our management has discussed the development and selection of the critical accounting estimates related to the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities with the audit and conflicts committee of our general partner's board of directors and that committee has reviewed the related disclosures discussed below.

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 Part II, Item 8, Financial Statements and Supplementary Data, Note 1.

Reserves for Environmental and Legal Contingencies

We currently have a reserve for environmental matters; however, we have no reserves for non-environmental legal matters. New environmental developments, such as increasingly strict environmental laws and regulations and new claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial cost and future liabilities. Also, new legal matters, adverse rulings or anticipated adverse rulings on pending legal matters, or proposed settlements on pending legal matters could result in substantial cost or future liabilities. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and determine the necessary requirements to remediate this damage. 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.

These assessments incorporate an analysis by our internal environmental engineering staff and consultation with legal counsel. An estimated range of the costs involved is derived and a liability for environmental remediation is recorded within this estimated range. The recorded liabilities for these issues represent our best estimates of remediation and restoration that may be required to comply with present laws and regulations. These estimates are based on forecasts of the total future costs related to environmental remediation. These estimates change periodically as additional or better information becomes available as to the extent of site remediation required, if any. Certain changes could occur that would materially affect our estimates and assumptions related to costs for environmental remediation. If we become subject to more stringent environmental remediation costs at known sites, if we discover additional contamination, discover previously unknown sites, or become subject to related personal or property damage, we could incur material costs in connection with the environmental remediation. Accordingly, management believes that estimates related to the accrual of environmental remediation liabilities are critical to our results of operations.

As of December 31, 2003, our Natural Gas Pipelines and Plants segment had a liability for environmental remediation of $21 million which was derived from a range of reasonable estimates based upon our studies and site surveys described above. In accordance with Statement of Financial Accounting Standards No. 5 "Accounting for Contingencies" and FASB Interpretation No. 14, "Reasonable Estimation of the Amount of a Loss," we used the low end of the range which is our best estimate of the loss. For environmental remediation sites known as of December 31, 2003, if the highest estimate from the range (based upon information presently available) were recorded, the total estimated liability would have been $43 million at December 31, 2003.

Asset Impairment

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

Depreciation, Depletion and Amortization 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, depletion and amortization 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.

If the average estimated useful lives of our depreciable assets were to change, the most significant impact would be on depreciation, depletion and amortization expense. A majority of this impact would be related to our pipeline assets. If the average estimated remaining useful lives were to decrease by 10 percent, the annual depreciation, depletion and amortization expense for our total assets would increase by $11.0 million, of which $7.3 million would be related to our pipelines. If the average estimated remaining useful lives were to increase by 10 percent, the annual depreciation, depletion and amortization expense for our total assets would decrease by $9.0 million, of which $5.9 million would be related to our pipelines. The remaining variances in depreciation, depletion and amortization expense are spread across our other asset groups — platforms and facilities, processing facilities and storage facilities.

Revenue and Cost of Natural Gas and Other Products Estimates

Each month we record an estimate for our operating revenues and cost of natural gas, oil and other products, including lost and unaccounted for, along with a true-up of the prior month's estimate to equal prior month's actual data. Accordingly, there is one month of estimated data recorded in our operating revenues and cost of natural gas and other products accounts for the years ended December 31, 2003, 2002 and 2001. The estimates are based on actual volume and price data through the first part of the month then extrapolated to the end of the month, adjusted accordingly for any known or expected changes in volumes or rates through the end of the month. Based on average monthly revenues and cost of natural gas and other products, a variance of 10 percent could impact revenues up to a positive or negative $7.3 million, of which $6.1 million is related to the Natural Gas Pipelines and Plants segment, and cost of natural gas and other products up to a positive or negative $2.4 million, of which $2.0 million is related to the Natural Gas Pipelines and Plants segment.

Price Risk Management Activities

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

One of the primary factors that can have an impact on our results each period is the price assumptions used to value our cash flow hedges. We use published market price information where available, or quotations from traders in the market to find executable bids and offers. If the fair value of our hedges cannot be determined from readily available market-based information, we use internal valuation techniques or models to estimate the fair value of such instruments. Such modeling techniques generally are only required to extrapolate the prices of the NGL (for which market-based prices are not readily available beyond three to six months) based on historical pricing relationships between natural gas, crude oil and the NGL components. Our estimates also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. A 10 percent increase or decrease in the forward price curves at December 31, 2003, would change our hedge liability by $8.8 million with an eventual loss reported in the results operations when the hedged items settled. These changes would impact our Natural Gas Pipelines and Plants segment.

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

Volume Measurement

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

Natural Gas Imbalances

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

Depending on our net position, a change in natural gas prices of 10 percent could positively or negatively affect our results of operations by $2.9 million, primarily in our Natural Gas Pipelines and Plants segment.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

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 effective, which will impact our accounting when these rules are adopted in the future. Some of these new rules may have an impact on our critical accounting policies.

RISK FACTORS AND CAUTIONARY STATEMENT

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

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

Other than the subsection below entitled "Risks Related to Our Proposed Merger with Enterprise", the following is a discussion of the risks associated with our business, structure and other matters generally as it existed on December 31, 2003 and does not take into account or assume the consummation of our proposed merger with Enterprise.

Risks Related to Our Proposed Merger with Enterprise

Because the consideration that our unitholders will receive in the proposed merger with Enterprise is based on a fixed exchange ratio, the market value of our common units may be significantly affected by changes in the market value of Enterprise common units.

At the effective time of the merger, each holder of GulfTerra common units will receive 1.81 Enterprise common units for each GulfTerra common unit held. Because this exchange ratio is fixed, the market value of the consideration that GulfTerra unitholders will receive depends on the trading price of Enterprise common units. Accordingly, any changes in the market value of Enterprise common units prior to the effective time of the merger would likely affect the market value of GulfTerra common units, regardless of whether there had been any change in the market's perception of GulfTerra's business, assets, liabilities or prospects.

We have expended and will expend significant time and resources on the merger.

In addition to the economic costs associated with pursuing a merger, our management is devoting substantial time and other human resources to the proposed transaction and related matters. Towards this end, our management and personnel are making the necessary filings, seeking the necessary approvals (including unitholder approval) and preparing for the merger closing. These activities, when coupled with the limitations imposed on us under the merger agreement, are likely to limit our ability to pursue other attractive non-organic business opportunities, including potential joint ventures, acquisitions and other transactions. In addition, to be consummated, the merger must be approved by Enterprise's unitholders and by our unitholders; we must receive approval from the Federal Trade Commission; and all of the other conditions to closing must have either been satisfied or waived. If the merger is not consummated, for any reason, we probably will not receive a significant return on our merger-related efforts.

Risks Related to Our Business

Our indebtedness could adversely restrict our ability to operate, affect our financial condition and prevent us from fulfilling our obligations under our debt securities.

We have a significant amount of indebtedness and the ability to incur substantially more indebtedness. As of December 31, 2003, we had approximately $682 million outstanding of senior secured indebtedness, approximately $168.1 million outstanding of accounts payable and accrued gas purchase costs and $1.13 billion outstanding under indentures related to our senior unsecured and senior subordinated notes.

From time to time, our joint ventures also incur indebtedness. As of December 31, 2003, Poseidon Oil Pipeline Company, L.L.C., in which we own a 36 percent interest, had $123 million outstanding under its revolving credit facility, Deepwater Gateway, L.L.C., in which we own a 50 percent interest, had $155 million outstanding under its project finance loan and Cameron Highway Oil Pipeline Company, in which we own a 50 percent joint venture ownership interest, had $125 million outstanding under its project loan facility. If Deepwater Gateway defaults on its payment obligations, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. Our obligation to make such a payment is collateralized by substantially all of our assets on the same basis as our obligations under our credit facility.

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 notes and our senior subordinated notes and our credit facilities. Among other things, these covenants limit the ability of us and our subsidiaries, except for our unrestricted subsidiaries, to:

- incur additional indebtedness or liens;
- make payments in respect of or redeem or acquire any debt or equity issued by us;
- sell assets;
- make loans or investments;
- acquire or be acquired by other companies; and
- amend some of our contracts.

We do not have the right to prepay the balance outstanding under our senior subordinated notes without incurring substantial economic penalties. The restrictions under our indebtedness may prevent us from engaging in certain transactions which might otherwise be considered beneficial to us and could have other important consequences to you. For example, they could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to make distributions to unitholders, including our minimum quarterly distribution amounts, to fund future working capital, capital expenditures and other general partnership requirements, to engage in future acquisitions, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness;
- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate; and
- place us at a competitive disadvantage as compared to our competitors that have less debt.

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

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for qualified assets.

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

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

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

Our growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

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

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

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

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

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

Our actual construction, development and acquisition costs could exceed our forecast, and our cash flow from construction and development projects may not be immediate.

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

- using cash from operations;
- delaying other planned projects;
- incurring additional indebtedness; or
- issuing additional debt or equity.

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

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

We will be adversely affected if we cannot negotiate an extension or replacement on commercially reasonable terms of three material contracts which account for approximately 70 percent of the volume attributable to the San Juan gathering system during 2003 and 2002 and which expire between 2006 and 2008.

For the year ended December 31, 2003 and 2002, approximately 70 percent of the volume attributable to the San Juan gathering system is derived from contracts with three major customers, Burlington Resources, ConocoPhillips and BP. These contracts expire in December of 2008, 2006 and 2006. If we are not able to successfully negotiate replacement contracts, or if the replacement contracts are on less favorable terms, the effect on us will be adverse. The following table indicates the percentage revenue generated by each contract in relation to the indicated denominator for the years ended December 31, 2003 and 2002:

Base Revenue	Burlington Resources	ConocoPhillips	BP	Total
2003				
San Juan gathering revenue	29.7%	25.7%	17.3%	72.7%
Total revenue of GulfTerra Energy Partners, L.P.	4.3%	3.7%	2.5%	10.5%
2002				
San Juan gathering revenue[(1)]	30.6%	20.9%	14.5%	66.0%
Total revenue of GulfTerra Energy Partners, L.P.[(1)]	6.9%	4.7%	3.3%	14.9%

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

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 notes and our senior subordinated notes, are fixed and the interest rates on some of our other indebtedness, like our credit facility and the credit facilities of our joint ventures, are variable. Our results of operations and our cash flow, as well as our access to future capital and our ability to fund our growth strategy, could be adversely affected by significant increases or decreases in interest rates.

Changes in the prices of hydrocarbon products may adversely affect our results of operations, cash flows and financial condition.

We gather, transport, process, fractionate and store natural gas, NGLs and crude oil. As such, our results of operations, cash flows and financial position may be adversely affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. In general terms, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are impossible to control. These factors include:

- the level of domestic production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and natural gas producing nations;
- the availability of transportation systems with adequate capacity;
- the availability of competitive fuels;

• fluctuating and seasonal demand for oil, natural gas and NGLs; and

• conservation and the extent of governmental regulation of production and the overall economic environment.

The profitability of our natural gas processing operations will depend upon the spread between NGL product prices and natural gas prices. A reduction in the spread between NGL product prices and natural gas prices can result in a reduction in demand for fractionation, processing and NGL storage services and, thus, may adversely affect our results of operations and cash flows from these activities. In addition, our natural gas processing activities will be exposed to commodity price risk associated with the relative price of NGLs to natural gas under our "keep-whole" natural gas processing contracts. Under these types of agreements, we take title to NGLs that we extract from the natural gas stream and are obligated to pay market value, based on natural gas prices, for the energy extracted from the natural gas stream. When prices for natural gas increase, the cost to us of making these "keep-whole" payments will increase, and, where NGL prices do not experience a commensurate increase, we will realize lower margins from these transactions. As a result, changes in prices for natural gas compared to NGLs could have an adverse affect on our results of operations, cash flows and financial position.

We are also exposed to natural gas and NGL commodity price risk under natural gas processing and gathering and NGL fractionation contracts that provide for our fee to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. Over 95% of the volumes handled by our San Juan gathering system are fee-based arrangements, 80% of which are calculated as a percentage of a regional natural gas price index. A decrease in natural gas and NGL prices can result in lower margins from these activities, which may adversely affect our results of operations, cash flows and financial position.

A decline in the volume of natural gas, NGLs and crude oil delivered to our facilities could adversely affect our results of operations, cash flows and financial position.

Our profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in the exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities.

The crude oil, natural gas and NGLs available to our facilities will be derived from reserves produced from existing wells, which reserves naturally decline over time. To offset this natural decline, our facilities will need access to additional reserves. Additionally, some of our facilities will be dependent on reserves that are expected to be produced from newly discovered properties that are currently being developed.

Exploration and development of new oil and natural gas reserves is capital intensive, particularly offshore in the Gulf of Mexico. The flextrend (water depths of 600 to 1,500 feet) and deepwater (water depths greater than 1,500 feet) areas of the Gulf of Mexico in particular will require large capital expenditures by producers for exploration and development drilling, installing production facilities and constructing pipeline extensions to reach the new wells. Many economic and business factors are out of our control and can adversely affect the decision by producers to explore for and develop new reserves. These factors include relatively low oil and natural gas prices, cost and availability of equipment, regulatory changes, capital budget limitations or the lack of available capital. For example, a sustained decline in the price of natural gas and crude oil could result in a decrease in natural gas and crude oil exploration and development activities in the regions where our facilities are located. This could result in a decrease in volumes to our offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators which would have an adverse affect on our results from operations, cash flows and financial position. Additional reserves, if discovered, may not be developed in the near future or at all.

A reduction in demand for NGL products by the petrochemical, refining or heating industries could adversely affect our results of operations, cash flows and financial position.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could adversely affect our results of operations, cash flows and financial position.

Our GTM Texas fractionation facilities are dedicated to a single customer, the loss of which could adversely affect us.

In connection with our acquisition of our GTM Texas fractionation facilities, we entered into a 20-year fee-based transportation and fractionation agreement and have dedicated all of the capacity of our fractionation facilities to a subsidiary of El Paso Corporation. In that agreement, 100 percent of the NGL derived from processing operations at seven natural gas processing plants in south Texas owned by subsidiaries of El Paso Corporation are delivered to our NGL transportation and fractionation facilities. Effectively, we will receive a fixed fee for each barrel of NGL transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. El Paso Corporation's subsidiary will bear substantially all of the risks and rewards associated with changes in the commodity prices for NGL produced at the EPN Texas fractionation facilities.

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

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, use, emission or disposal of substances and wastes. Moreover, as with other companies engaged in similar or related businesses, our operations always have some risk of environmental costs and liabilities because we handle petroleum products.

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

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

We will face competition from third parties to gather, transport, process, fractionate, store or otherwise handle oil, natural gas and other petroleum products.

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

- geographic proximity to the production;
- costs of connection;
- available capacity;
- rates; and
- access to markets.

FERC regulation and a changing regulatory environment could affect our cash flow.

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

- rate structures;
- rates of return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; and
- to an extent, the level of competition in that regulated industry.

In November 2003, the FERC issued a Final Rule extending its standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since our HIOS natural gas pipeline and Petal natural gas storage facility, including the 60-mile Petal gas pipeline, are interstate facilities as defined by the Natural Gas Act, the regulations dictate how HIOS and Petal conduct business and interact with all energy affiliates of El Paso Corporation and us.

The standards of conduct require us, absent a waiver, to functionally separate our HIOS and Petal interstate facilities from our other entities. We must dedicate employees to manage and operate our interstate facilities independently from our other Energy Affiliates. This employee group must function independently and is prohibited from communicating non-public transportation information or customer information to its Energy Affiliates. Separate office facilities and systems are necessary because of the requirement to restrict affiliate access to interstate transportation information. The Final Rule also limits the sharing of employees and offices with Energy Affiliates. The Final Rule was effective on February 9, 2004, subject to possible rehearing. On that date, each transmission provider filed with the FERC and posted on the internet website a plan and schedule for implementing this Final Rule. By June 1, 2004, written procedures implementing this Final Rule will be posted on the internet website. Requests for rehearing have been filed and are pending. At this time, we cannot predict the outcome of these requests, but at a minimum, adoption of the regulations in the form outlined in the Final Rule will place additional administrative and operational burdens on us.

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

Our pipeline integrity program may impose significant costs and liabilities to us.

In December 2003, the U.S. Department of Transportation issued a Final Rule requiring pipeline operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm in "high consequence areas", or HCA. The final rule requires operators to (1) perform ongoing assessments of pipeline integrity; (2) identify and characterize applicable threats to pipeline segments that could impact an HCA; (3) improve data collection, integration and analysis; (4) repair and remediate the pipeline as necessary; and (5) implement preventive and mitigative actions. The final rule incorporates the requirements of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. The Final Rule is effective as of January 14, 2004. At this time, we cannot predict the impact this Final Rule will have on our results of operations.

Our pipeline integrity testing program, which is intended to assess and repair the integrity of our pipelines, is underway. While the costs associated with the pipeline integrity testing itself are not large, the results of these tests could cause us to incur significant and unanticipated capital and operating expenditures to ensure the safe and reliable operation of our pipelines.

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

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

If one or more facilities that are owned by us or that deliver oil, natural gas or other products to us is damaged or otherwise affected by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of our storage contracts obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' natural gas is in our possession. Any event that interrupts the fees generated by our energy infrastructure assets, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying our interest obligations as well as unitholder distributions and, accordingly, adversely impact the market price of our securities. We expect to maintain adequate insurance coverages, although it will not cover many types of interruptions that might occur. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew our existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business. An escalation of political tensions in the Middle East and elsewhere could result in increased volatility in the world's energy markets and result in a material adverse effect on our business.

Conflicts of Interest Risks

El Paso Corporation and its subsidiaries have conflicts of interest with us and, accordingly, you.

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

- we have historically entered into transactions with each other, including some relating to operating and managing assets, acquiring and selling assets, and performing services;
- we share personnel, assets, systems and other resources;
- from time to time, we compete for business and customers; and
- from time to time, we both may have an interest in acquiring the same asset, business or other business opportunity.

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

- in November 2002, we acquired the San Juan assets from El Paso Corporation for approximately $782 million, net $764 million adjusted for capital expenditures and actual working capital acquired;
- in April 2002, we acquired the EPN Holding assets from El Paso Corporation for approximately $750 million, net $752 million after adjustments for capital expenditures and actual working capital acquired;
- in October 2003, we released El Paso Corporation from its obligation, in connection with our November 2002 San Juan asset acquisition, to repurchase the Chaco plant from us in 2021 in exchange for El Paso Corporation contributing specified communication assets to us;
- in October 2003, we redeemed our Series B preference units, which were owned by a subsidiary of El Paso Corporation, for approximately $156 million; and
- pursuant to a general and administrative services agreement, subsidiaries of El Paso Corporation provide us administrative, operational and other services.

In addition, we and El Paso Corporation and its subsidiaries share and, therefore will compete for, the time and effort of El Paso Corporation personnel who provide services to us, including directors, officers and other personnel. Personnel of the general partner and its affiliates 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 and our unitholders, on the other. Additionally, some of these directors, officers and other personnel 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 those of our common unit holders.

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

- compensation paid to the general partner, which includes incentive distributions and reimbursements for reasonable general and administrative expenses;
- payments to the general partner and its affiliates for any services rendered to us or on our behalf;
- our general partner's determination of which direct and indirect costs we must reimburse; and
- our general partner's determination to establish cash reserves under certain circumstances and thereby decrease cash available for distributions to unitholders.

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

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

Because we depend upon El Paso Corporation and its subsidiaries for employees to manage our business and affairs, a decrease in the availability of employees from El Paso Corporation and its affiliates could adversely affect us.

We have no employees. In managing our business and affairs, our general partner relies on employees of El Paso Corporation and its affiliates under a general and administrative services agreement between our general partner, on one hand, and subsidiaries of El Paso Corporation, on the other hand. Those employees will act on behalf of and as agents for us. A decrease in the availability of employees from El Paso Corporation and its affiliates could adversely affect us.

El Paso Corporation and its affiliates may sell units or other limited partner interests in the trading market, which could reduce the market price of common units.

As of the date of this annual report, El Paso Corporation and its affiliates own 10,310,045 common units and 10,937,500 Series C units that may ultimately be converted into common units. In the future, they may acquire additional interest or dispose of some or all of their interest. If they were to dispose of a substantial portion of their interest in the trading markets, it could reduce the market price of common units. Our partnership agreement, and other agreements to which we are party, allow our general partner and certain of its subsidiaries to cause us to register for sale the partnership interests held by such persons, including common units. These registration rights allow our general partner and its subsidiaries to request registration of those partnership interests and to include any of those securities in a registration of other capital securities by us.

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

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

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

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

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

Provisions of the partnership agreement also purport to modify the fiduciary duty standards to which our general partner would otherwise be subject under Delaware law, under which a general partner owes its limited partners the highest duties of good faith, fairness and loyalty. The duty of loyalty would generally prohibit our general partner from taking any action or engaging in any transaction as to which it had a conflict of interest. The partnership agreement permits our general partner to exercise the discretion and authority granted to it in that agreement in managing us and in conducting its retained operations, so long as its actions are not inconsistent with our interests. Our general partner and its officers and directors may not be liable to us or to unitholders for certain actions or omissions which might otherwise be deemed to be a breach of fiduciary duty under Delaware or other applicable state law. Further, the partnership agreement requires us to indemnify our general partner to the fullest extent permitted by law, which indemnification, in light of the exculpatory provisions in the partnership agreement, could result in us indemnifying our general partner for negligent acts. Neither El Paso Corporation nor any of its other subsidiaries, other than our general partner, owes fiduciary duties to us.

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 debt service;
- providing for future operating and capital expenditures;
- 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 affiliates 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 affiliates, on the other hand, were not and may not be the result of arm's-length negotiations and, as a result, those agreements may not be as profitable or advantageous to us and may produce a lower distribution for our unitholders than those negotiated at arm's-length.

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

Risks Inherent in an Investment in Our Securities

We may not have sufficient cash from operations to pay distributions at the current level following establishment of cash reserves and payments of fees and expenses, including payments to our general partner.

Because distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our general partner. These factors include but are not limited to the following:

- the level of our operating costs;
- the level of competition in our business segments;
- prevailing economic conditions;
- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and our debt service requirements;
- fluctuation in our working capital needs;
- the cost of acquisitions, if any; and
- the amount, if any, of cash reserves established by our general partner, in its direction.

In addition, you should be aware that our ability to pay the minimum quarterly distribution each quarter depends primarily on our cash flow, including cash flow from financial reserves, working capital borrowings and distributions from our unconsolidated affiliates, and not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

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

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

Our general partner may not be removed as our general partner except upon approval by the affirmative vote of the holders of at least 66⅔ percent of our outstanding limited partner interests (excluding limited partner interests owned by our general partner and its affiliates), subject to the satisfaction of certain conditions. Any removal of our general partner is not effective until the holders of a majority of our outstanding limited partner interests approve a successor general partner. Before the holders of outstanding limited partner interests may remove our general partner, they must receive an opinion of counsel that:

- such action will not result in the loss of limited liability of any limited partner or of any member of any of our subsidiaries or cause us or any of our subsidiaries to be taxable as a corporation or to be treated as an association taxable as a corporation for federal income tax purposes; and
- all required consents by any regulatory authorities have been obtained.

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

We may issue additional securities, which will dilute interests of unitholders and may adversely effect their voting power.

We can issue additional common units, preference units and other capital securities representing limited partner interests, including securities with rights to distributions and allocations or in liquidation equal or superior to the equity securities held by existing unitholders, for any amount and on any terms and conditions established by our general partner. For example, in 2003, we issued through public and private offerings 14,026,109 additional common units and 80 Series F convertible units, which may ultimately convert into a maximum of 8,329,679 common units. If we issue more limited partner interests, it will reduce each common unitholder's proportionate ownership interest in us. This could cause the market price of the common units to fall and reduce the cash distributions paid to our limited partners. Further, we have the ability to issue partnership interests with voting rights superior to the unitholders. If we issue any such securities, it could adversely affect the voting power of the common units.

Our general partner has anti-dilution rights.

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

Unitholders may not have limited liability in certain circumstances, including potentially having liability for the return of wrongful distributions.

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

- a court or government agency determined that we had not complied with that state's partnership statute; or
- our unitholders' rights to act together to remove or replace our general partner or take other actions under our partnership agreement were to constitute "control" of our business under that state's partnership statute.

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

Our general partner has a limited call right that may require unitholders to sell their limited partner interests at an undesirable time or price.

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

Our existing units are, and potentially any limited partner interests we issue in the future will be, subject to restrictions on transfer.

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

We may not be able to satisfy our obligation to repurchase debt securities upon a change of control.

Upon a change of control (among other things, the acquisition of 50 percent or more of El Paso Corporation's voting stock, or if El Paso Corporation and its subsidiaries no longer own more than 50 percent of our general partner, or the sale of all or substantially all of our assets), unless our creditors agreed otherwise, we would be required to repay the amounts outstanding under our credit facilities and to offer to repurchase our outstanding senior subordinated notes and possibly our outstanding senior notes at 101 percent of the principal amount, plus accrued and unpaid interest to the date of repurchase. We may not have sufficient funds available or be permitted by our other debt instruments to fulfill these obligations upon the occurrence of a change of control.

The existence of the Series F convertible units could depress the market price of our common units.

The terms on which we are able to obtain additional capital may be adversely affected while our Series F convertible units (and other securities convertible into or exercisable for common units) are outstanding because of the uncertainty and potential dilutive effect related to conversion or exercise of our Series F convertible units and other derivative securities.

The Series F convertible units were acquired by a single investor which resulted in concentrated ownership and could depress the market price of our common units.

All of our Series F convertible units were acquired by one investor, and assuming that investor retains a substantial portion of the Series F convertible units and converts them to common units, that investor could own approximately 15 percent of our outstanding common units. In the future, that investor may acquire additional common units or dispose of some or all of its common units. If that investor were to dispose of a substantial portion of its common units in the trading markets, it could reduce the market price of our common units.

Proposed state tax legislation may affect our cash flow and distributions.

Several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If certain states were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect that impact on 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 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) depends upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us. Distributions from our joint ventures are subject to the discretion of their respective management committees. In addition, from time to time, our joint ventures and some of our subsidiaries have separate credit arrangements that contain various restrictive covenants. Among other things, those covenants limit or restrict each such company's ability to make distributions to us under certain circumstances. Further, each joint venture's charter documents typically vest in its management committee sole discretion regarding distributions. Accordingly, our joint ventures and our unrestricted subsidiaries may not continue to make distributions to us at current levels or at all. For example, we expect to receive no distributions from Poseidon until it has completed its Front Runner pipeline project.

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

We cannot cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree.

Due to the nature of joint ventures, each participant (including us) in each of our joint ventures, including Poseidon, Deepwater Gateway, Cameron Highway Oil Pipeline Company and Coyote Gas Treating, LLC, has made substantial investments (including contributions and other commitments) in that joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features include a corporate governance structure that requires at least a majority in interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100 percent) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. For example, we expect to receive no distributions from Poseidon until it has completed its Front Runner pipeline project. Thus, without the concurrence of joint venture participants with enough voting interests, we cannot cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the particular joint venture or us. As of December 31, 2003, our aggregate investments in Deepwater Gateway, Cameron Highway Oil Pipeline Company, Coyote Gas Treating, L.L.C. and Poseidon totaled $33 million, $86 million, $16.7 million and $40 million.

In addition, each joint venture's charter documents typically vest in its management committee sole discretion regarding the occurrence and amount of distributions. Some of the joint ventures in which we participate have separate credit arrangements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture's ability to make distributions to us under certain circumstances. Accordingly, our joint ventures may be unable to make distributions to us at current levels or at all.

Moreover, we cannot be certain that any of the joint venture owners will not sell, transfer or otherwise modify their ownership interest in a joint venture, whether in a transaction involving third parties and/or the other joint venture owners. Any such transaction could result in us partnering with different or additional parties.

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 a 50 percent managing member interest in our general partner, common units, and Series C 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. If El Paso Corporation owns less than 50 percent of our general partner (including at the closing of our merger with Enterprise), that would constitute a change of control under our existing credit agreement, our senior subordinated notes indentures and possibly the indenture relating to the senior notes. In such a circumstance, much of our indebtedness for borrowed money would effectively become due and payable unless our creditors agreed otherwise, and we might be required to refinance our indebtedness, potentially on less advantageous terms.

Tax Risks

We have not received a ruling or assurances from the IRS with respect to our classification as a partnership.

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

Our tax treatment depends on our partnership status and if the IRS treats us as a corporation for tax purposes, it would adversely affect distributions to our unitholders and our ability to make payments on our debt securities.

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

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

We maintain uniformity of our limited partner interests through nonconforming depreciation conventions.

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

Unitholders can only deduct certain losses.

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

Unitholders' partnership tax information may be audited.

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

Unitholders' tax liability resulting from an investment in our limited partner interests could exceed any cash unitholders receive as a distribution from us or the proceeds from dispositions of those securities.

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

Tax-exempt organizations and certain other investors may experience adverse tax consequences from ownership of our securities.

Investment in our securities by tax-exempt organizations and regulated investment companies raises issues unique to such persons. Virtually all of our income allocated to a tax-exempt organization will be unrelated business taxable income and will be taxable to such tax-exempt organization. Additionally, very little of our income will qualify for purposes of determining whether an investor will qualify as a regulated investment company. Furthermore, an investor who is a nonresident alien, a foreign corporation or other foreign person will be required to file federal income tax returns and to pay taxes on his share of our taxable income because he will be regarded as being engaged in a trade or business in the United States as a result of his ownership of units or other limited partnership units. Distributions to foreign persons will be reduced by withholding taxes at the highest effective U.S. federal income tax rate for individuals. 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. The tax laws require that some types of entities, including some partnerships, register as "tax shelters" in response to the perception that they claim tax benefits that may be unwarranted. As a result, we may be audited by the IRS and tax adjustments may be made. The right of a unitholder owning less than a one percent profit interest in us to participate in the income tax audit process is limited. Further, any adjustments in our tax returns will lead to adjustments in each unitholder's returns and may lead to audits of each unitholder's returns and adjustments of items unrelated to us. Each unitholder would bear the cost of any expenses incurred in connection with an examination of its personal tax return.

Unitholders may have negative tax consequences if we default on our debt or sell assets.

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

We will treat each investor of units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

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

You will likely be subject to state and local taxes in states where you do not live as a result of an investment in our units.

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We may utilize derivative financial instruments to manage our exposure to movements in interest rates and commodity prices. In accordance with procedures established by our general partner, we monitor current economic conditions and evaluate our expectations of future prices and interest rates when making decisions with respect to risk management. We generally do not enter into derivative transactions for trading purposes and had no trading activities during 2003 and 2002.

Non-trading Commodity Price Risk

A majority of our commodity sales and purchases are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities.

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

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

In August 2002 in anticipation of our acquisition of the San Juan assets, we entered into derivative financial instruments to receive fixed prices for specified volumes of natural gas for the 2003 calendar year. The derivative is a fixed-for-floating commodity price swap on 30,000 MMBtu/d of natural gas at a weighted average receive price of $3.525 per Dth for delivery through December 2003. Since the derivative was not associated with our then current operating activities, it did not qualify for hedge accounting under SFAS No. 133. As a result, we accounted for this commodity price swap based upon mark-to-market accounting until we acquired the San Juan assets on November 27, 2002. With the acquisition of the San Juan assets, we designated the previously acquired fixed-for-floating commodity price swaps as a cash flow hedge. We recognized a gain of $0.4 million in income for the change in value from the date we entered the derivative until the San Juan acquisition date. In February and August 2003, we entered into additional derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. We are accounting for these derivatives as cash flow hedges under SFAS No. 133.

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

During 2003, we entered into additional derivative financial instruments to hedge a portion of our business' exposure to changes in NGL prices during 2003 and 2004. We entered into financial swaps for 3,500 barrels per day for February through June 2003, 3,200 barrels per day for July 2003, 4,900 barrels per day for August 2003, and 6,000 barrels per day for August 2003 through September 2004. The average fixed price received was $0.49 per gallon for 2003 and will be $0.47 per gallon for 2004 while we pay a monthly average floating price based on the OPIS average price for each month.

During 2002 and 2003, our GulfTerra Alabama Intrastate operation entered into sales contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time at a fixed price based on the SONAT-Louisiana index (Southern Natural Pipeline index as published by the periodical "Inside FERC") plus a margin. We simultaneously entered into fixed-for-floating commodity price swaps for comparable volumes of natural gas at fixed prices indicated in the SONAT-Louisiana index that settle over the same time periods as the underlying sales contracts.

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

Fixed-for-Floating Commodity Price Swaps — GulfTerra Alabama Intrastate	Contract Value 2003	Contract Value 2002
Contract volumes (in MDth)	85	95
Weighted average price received (per Dth)	$6.09	$4.766
Weighted average price paid (per Dth)	$5.18	$3.862
Swap Fair Value ($ in thousands)[a]	$ 77	$ 86

[a] Fair value is determined from prices indicated in the SONAT-Louisiana index as developed from market data.

Fixed-for-Floating Commodity Price Swaps — San Juan	Contract Value 2003	Contract Value 2002
Contract volumes (in MDth)	10,980	10,950
Weighted average price received (per Dth)	$ 4.23	$ 3.525
Weighted average price paid (per Dth)	$ 4.75	$ 3.963
Swap Fair Value ($ in thousands)[b]	$(5,805)	$(4,796)

[b] Fair value is determined from prices indicated in the San Juan index as developed from market data.

Fixed-for-Floating Commodity Price Swaps — Indian Basin & Chaco Plants (NGLs)	Contract Value 2003	Contract Value 2002
Contract volumes (in Mbbl)	1,644	—
Weighted average price received (per gallon)	$ 0.47	$—
Weighted average price paid (per gallon)	$ 0.52	$—
Swap Fair Value ($ in thousands)	$(3,300)	$—

As reflected in the tables above, at December 31, 2003 we have an unrealized loss associated with our natural gas and NGL fixed-for-floating commodity price swaps of approximately $9.0 million.

Interest Rate Risk

We utilize both fixed and variable rate long-term debt, and are exposed to market risk resulting from the variable interest rates under our revolving credit facility and senior secured term loan and from our fixed for floating interest rate swap agreement on $250 million of our 8½% senior subordinated notes due 2011. We are exposed to similar risk under the various joint venture credit facilities and loan agreements. Since we have $1,137.2 million outstanding under our indentures at fixed interest rates ranging from 6¼% to 10⅝% at December 31, 2003, we have not benefited from the recent declines in interest rates. On the other hand, had interest rates increased, we would not have incurred additional interest costs.

The table below depicts principal cash flows and related weighted average interest rates of our debt obligations, by expected maturity dates at December 31, 2003. The carrying amounts of our revolving credit facility, GulfTerra Holding term credit facility and the senior secured term loans at December 31, 2003 and 2002, 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 notes and senior subordinated notes has been determined based on quoted market prices for the same or similar issues.

	December 31, 2003										December 31, 2002	
	Average Interest Rate	Expected Fiscal Year of Maturity of Carrying Amounts							Fair Value		Carrying Amount	Fair Value
		2004	2005	2006	2007	2008	Thereafter	Total				
	(Dollars in millions)											
Variable Rate Debt:												
Revolving credit facility	3.2%	$ —	$ —	$382.0	$ —	$ —	$ —	$382.0	$382.0		$491.0	$491.0
GulfTerra Holding term credit facility	—	—	—	—	—	—	—	—	—		160.0	160.0
Senior secured term loan	3.4%	3.0	3.0	3.0	3.0	288.0	—	300.0	300.0		160.0	160.0
Senior secured acquisition term loan	—	—	—	—	—	—	—	—	—		237.5	237.5
Fixed Rate Debt:												
10 3/8% senior subordinated notes due 2009	10.4%	—	—	—	—	—	175.0	175.0	189.9		175.0	185.5
8 1/2% senior subordinated notes due 2011	8.5%(1)	—	—	—	—	—	167.5	167.5	188.4		250.0	252.5
8 1/2% senior subordinated notes due 2011	8.5%(1)	—	—	—	—	—	156.6	156.6	173.4		234.3	214.5
10 5/8% senior subordinated notes due 2012	10.6%	—	—	—	—	—	133.1	133.1	165.5		198.5	205.5
8 1/2% senior subordinated notes due June 2010	8.5%	—	—	—	—	—	255.00	255.0	290.7		N/A	N/A
6 1/4% senior notes due June 2010	6.3%	—	—	—	—	—	250.00	250.0	262.5		N/A	N/A

(1) The December 31, 2003 amounts exclude the market value ($7.4 million liability at December 31, 2003) of our interest rate swap accounted as a fair value hedge.

At December 31, 2003, we had variable rate debt outstanding with an aggregate principal balance of $682.0 million and a weighted average interest rate of 3.3%. The following table illustrates the amount of the increase in net income from a decrease in interest rates or the amount of the decrease in income from an increase in interest rates under four possible scenarios based upon the aggregate balance of variable rate debt outstanding at December 31, 2003 (dollars in millions):

Aggregate Variable-rate Debt Subject to repricing	Effect on income resulting from a change in interest rates of:			
	25 basis points*	50 basis points*	75 basis points*	100 basis points*
$682.0	$1.7	$3.4	$5.1	$6.8

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

Because the closing of the merger with Enterprise will constitute a change of control, and thus a default, under our credit facility, we will either amend or refinance our credit facility prior to that closing. In addition, because the closing of the Enterprise merger will constitute a change of control under our indentures, we will be required to offer to repurchase all of our senior subordinated notes (and possibly our senior notes) at 101 percent of their par value after the closing. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the close of the merger. We and Enterprise can agree on the date of the merger closing after the receipt of all necessary approvals. We do not intend to close until appropriate financing is in place.

In December 2003, we exercised our right, under the terms of our senior subordinated notes' indentures, to repay, at a premium, approximately $269.4 million in principal amounts of those senior subordinated notes. The indentures provide that, within 90 days of an equity offering, we can call up to 33% of the original face amount at a premium. The amount we can repay is limited to the net proceeds of the offering. We recognized additional costs totaling $29.1 million resulting from the payment of the redemption premiums and the write-off of unamortized debt issuance costs, premiums and discounts.

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

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480.0 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. At December 31, 2003, the fair value of the swap was a liability, included in non-current liabilities, of approximately $7.4 million. The fair value of the hedged debt decreased by the same amount.

At December 31, 2003, Poseidon Oil Pipeline Company, L.L.C., one of our unconsolidated affiliates, has a revolving credit facility with $185 million of total borrowing capacity and $123 million outstanding. 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 amounts outstanding on their variable rate revolving credit facility. This interest rate swap expired in January 2004 and was not renewed.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

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

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME — (Continued)
(In thousands, except per unit amounts)

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

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 30,425	$ 36,099
Accounts receivable, net		
Trade	43,203	90,379
Unbilled trade	63,067	49,140
Affiliates	47,965	83,826
Affiliated note receivable	3,768	—
Other current assets	20,595	3,451
Total current assets	209,023	262,895
Property, plant and equipment, net	2,894,492	2,724,938
Intangible assets	3,401	3,970
Investments in unconsolidated affiliates	175,747	95,951
Other noncurrent assets	38,917	43,142
Total assets	$3,321,580	$3,130,896
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	$ 113,820	$ 120,140
Affiliates	38,870	86,144
Accrued gas purchase costs	15,443	6,584
Accrued interest	11,199	15,028
Current maturities of senior secured term loan	3,000	5,000
Other current liabilities	27,035	21,195
Total current liabilities	209,367	254,091
Revolving credit facility	382,000	491,000
Senior secured term loans, less current maturities	297,000	552,500
Long-term debt	1,129,807	857,786
Other noncurrent liabilities	49,043	23,725
Total liabilities	2,067,217	2,179,102
Commitments and contingencies		
Minority interest	1,777	1,942
Partners' capital		
Limited partners		
Series B preference units; 125,392 units in 2002 issued and outstanding	—	157,584
Common units; 58,404,649 and 44,030,314 units in 2003 and 2002 issued and outstanding	898,072	433,150
Series C units; 10,937,500 units in 2003 and 2002 issued and outstanding	341,350	350,565
General partner	13,164	8,553
Total partners' capital	1,252,586	949,852
Total liabilities and partners' capital	$3,321,580	$3,130,896

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2003	2002	2001
Cash flows from operating activities			
Net income	$ 163,139	$ 97,688	$ 55,149
Less cumulative effect of accounting change	1,690	—	—
Less income from discontinued operations	—	5,136	1,097
Income from continuing operations	161,449	92,552	54,052
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	—	—	3,921
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	(11,373)	(13,639)	(8,449)
Distributions from unconsolidated affiliates	12,140	17,804	35,062
(Gain) loss on sale of long-lived assets	(18,679)	473	11,367
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	12,544	2,434	—
Amortization of debt issuance costs	7,498	4,443	3,608
Other noncash items	3,445	4,429	544
Working capital changes, net of acquisitions and non-cash transactions			
Accounts receivable	66,441	(167,536)	(41,037)
Other current assets	(9,762)	(12,612)	125
Other noncurrent assets	(1,540)	467	(10,379)
Accounts payable	(45,829)	143,553	(672)
Accrued gas purchase costs	8,859	4,223	(2,776)
Accrued interest	(3,829)	9,330	3,574
Other current liabilities	(8,928)	13,086	(235)
Other noncurrent liabilities	(3,114)	(377)	(1,067)
Net cash provided by continuing operations	268,168	170,756	82,416
Net cash provided by discontinued operations	—	5,244	4,968
Net cash provided by operating activities	268,168	176,000	87,384
Cash flows from investing activities			
Development expenditures for oil and natural gas properties	(145)	(1,682)	(2,018)
Additions to property, plant and equipment	(332,019)	(202,541)	(508,347)
Proceeds from the sale and retirement of assets	77,911	5,460	109,126
Additions to investments in unconsolidated affiliates	(35,536)	(38,275)	(1,487)
Proceeds from the sale of investments in unconsolidated affiliates	1,355	—	—
Repayments on note receivable	1,238	—	—
Cash paid for acquisitions, net of cash acquired	(20)	(1,164,856)	(28,414)
Net cash used in investing activities of continuing operations	(287,216)	(1,401,894)	(431,140)

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)
(In thousands)

	Year Ended December 31,		
	2003	2002	2001
Net cash provided by (used in) investing activities of discontinued operations	—	186,477	(68,560)
Net cash used in investing activities	(287,216)	(1,215,417)	(499,700)
Cash flows from financing activities			
Net proceeds from revolving credit facility	533,564	366,219	559,994
Repayments of revolving credit facility	(647,000)	(177,000)	(581,000)
Net proceeds from GulfTerra Holding term credit facility	—	530,136	—
Repayment of GulfTerra Holding term credit facility	—	(375,000)	—
Repayment of GulfTerra Holding term loan	(160,000)	—	—
Net proceeds from senior secured acquisition term loan	(23)	233,236	—
Repayment of senior secured acquisition term loan	(237,500)	—	—
Net proceeds from senior secured term loan	299,512	156,530	—
Repayment of senior secured term loan	(160,000)	—	—
Net proceeds from issuance of long-term debt	537,426	423,528	243,032
Repayments of long-term debt	(269,401)	—	—
Repayment of Argo term loan	—	(95,000)	—
Distributions to minority interests	(1,242)	—	—
Net proceeds from issuance of common units	509,010	150,159	286,699
Redemption of Series B preference units	(155,673)	—	(50,000)
Contributions from general partner	3,098	4,095	2,843
Distributions to partners	(238,397)	(154,468)	(106,409)
Net cash provided by financing activities of continuing operations	13,374	1,062,435	355,159
Net cash provided by (used in) financing activities of discontinued operations	—	(3)	49,960
Net cash provided by financing activities	13,374	1,062,432	405,119
Increase (decrease) in cash and cash equivalents	(5,674)	23,015	(7,197)
Cash and cash equivalents at beginning of year	36,099	13,084	20,281
Cash and cash equivalents at end of year	$ 30,425	$ 36,099	$ 13,084

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

	Series B Preference Units[1]	Series B Preference Unitholders	Series C Units[2]	Series C Unitholders	Common Units	Common Unitholders	General Partner[3]	Total
Partners' capital at January 1, 2001	170	$ 175,668	—	$ —	31,550	$ 132,802	$ 2,601	$ 311,071
Net income[4]	—	17,228	—	—	—	13,260	24,661	55,149
Other comprehensive loss	—	—	—	—	—	(1,259)	(13)	(1,272)
Issuance of common units	—	—	—	—	8,189	286,699	—	286,699
Issuance of unit options	—	—			—	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
Net income[4]	—	14,688	—	1,507	—	39,360	42,133	97,688
Issuance of Series C units	—	—	10,938	350,000	—	—	—	350,000
Other comprehensive loss	—	—	—	(942)	—	(3,364)	(44)	(4,350)
Issuance of common units	—	—	—	—	4,291	156,072	—	156,072
Issuance of unit options	—	—	—	—	—	89	—	89
General partner contribution related to the issuance of Series C units and common units	—	—	—	—	—	—	4,095	4,095
Cash distributions	—	—	—	—	—	(111,767)	(42,701)	(154,468)
Partners' capital at December 31, 2002	125	$ 157,584	10,938	$350,565	44,030	$ 433,150	$ 8,553	$ 949,852
Net income[4]	—	11,792	—	15,421		66,495	69,431	163,139
Other comprehensive loss	—		—	(467)	—	(2,865)	(73)	(3,405)
Issuance of common units	—	—	—	—	14,056	494,812	—	494,812
Issuance of Series F units	—	—	—	—	—	4,104	—	4,104
Redemption of unit options	—	—	—	—	319	10,094	—	10,094
Redemption of Series B preference units	(125)	(169,376)	—	1,919	—	9,686	2,098	(155,673)
Issuance of unit options and restricted units						1,687		1,687
General partner contribution related to the issuance of common units	—	—	—	—	—	—	3,098	3,098
Receipt of communication assets	—	—	—	4,100	—	18,942	233	23,275
Cash distributions	—	—	—	(30,188)	—	(138,033)	(70,176)	(238,397)
Partners' capital at December 31, 2003	—	$ —	10,938	$341,350	58,405	$ 898,072	$ 13,164	$1,252,586

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

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

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

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

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

Comprehensive Income

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

Accumulated Other Comprehensive Income (Loss)

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

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

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

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

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

Our sole general partner is GulfTerra Energy Company, L.L.C., a recently-formed Delaware limited liability company that is owned 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise, a publicly traded master limited partnership. El Paso Corporation (through its subsidiaries) owned 100 percent of our general partner until October 2003, when Goldman Sachs acquired a 9.9 percent interest in our general partner. In December 2003, El Paso Corporation reacquired Goldman Sachs' interest in our general partner and then sold a 50 percent interest in our general partner to a subsidiary of Enterprise.

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

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

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We account for investments in companies where we have the ability to exert significant influence over, but not control over operating and financial policies, using the equity method of accounting. Prior to May 2001, our general partner's approximate one percent non-managing interest in twelve of our subsidiaries represented the minority interest in our consolidated financial statements. In May 2001, we purchased our general partner's one percent non-managing ownership interest in twelve of our subsidiaries for $8 million. As a result of this acquisition, all of our subsidiaries, but not our equity investees, are wholly-owned by us.

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

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

Use of Estimates

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

Accounting for Regulated Operations

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

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

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

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts that we believe are uncollectible. We review collectibility regularly and adjust the allowance as necessary, primarily under the specific identification method. At December 31, 2003 and 2002, the allowance was $4.0 million and $2.5 million.

Natural Gas Imbalances

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

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

Property, Plant and Equipment

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

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

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

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

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

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

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

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

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143. The provisions of this statement relate primarily to our obligations to plug abandoned offshore wells that constitute part of our non-segment assets.

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

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

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

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

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

Year	Liability Balance as of January 1	Accretion	Other Change in Liability	Liability Balance as of December 31
		(In thousands)		
2003	$5,726	$442	$(246)[1]	5,922

[1] Abandonment work performed during the year ended December 31, 2003.

Goodwill and Other Intangible Assets

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

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

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

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

Impairment and Disposal of Long-Lived Assets

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

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

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

Capitalization of Interest

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

Debt Issue Costs

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

Revenue Recognition and Cost of Natural Gas and Other Products

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

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

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

As of July 1, 2003, HIOS implemented new rates, subject to a refund, and we established a reserve for our estimate of the refund obligation. We will continue to review our expected refund obligation as the rate case moves through the hearing process and may increase or decrease the amounts reserved for refund obligation as our expectation changes.

Environmental Costs

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

Accounting for Price Risk Management Activities

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

- exchange-traded future contracts that involve cash settlement;

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

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

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

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

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

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

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

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

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

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

Income Taxes

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

Income (Loss) per Common Unit

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

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

Comprehensive Income

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

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

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

Accounting for Stock-Based Compensation

We use the intrinsic value method established in Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, to value unit options issued to individuals who are on our general partner's current board of directors and for those grants made prior to El Paso Corporation's acquisition of our general partner in August 1998 under our Omnibus Plan and Director Plan. For the years ending December 31, 2003, 2002 and 2001, the cost of this stock-based compensation had no impact on our net income, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. We use the provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, to account for all of our other stock-based compensation programs.

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

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

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

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

Accounting for Debt Extinguishments

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

Accounting for Costs Associated with Exit or Disposal Activities

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

Accounting for Guarantees

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

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

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

New Accounting Pronouncements Issued But Not Yet Adopted

Consolidation of Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*. This interpretation defines a variable interest entity (VIE) as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires a company to consolidate a VIE if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. In December 2003, the FASB issued FIN 46-R, which amended FIN No. 46, to extend its effective date until the first quarter of 2004 for all types of entities except special purpose entities (SPE's). In addition, FIN No. 46-R also limited the scope of FIN No. 46 to exclude certain joint ventures of other entities that meet the characteristics of businesses.

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

2. Acquisitions and Dispositions

Merger with Enterprise

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

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

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

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

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

Exchange with El Paso Corporation

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

As a result of the October 2003 exchange, we revised our estimate for the depreciable life of the Chaco plant from 19 to 30 years, the estimated remaining useful life of the Chaco plant. Depreciation expense will decrease approximately $0.5 million and $2.3 million on a quarter and annual basis.

Cameron Highway Oil Pipeline Company

Refer to Note 3 for a discussion related to our sale of a 50 percent interest in Cameron Highway Oil Pipeline.

San Juan Assets

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

- 100 percent of El Paso Field Services' San Juan Gathering and Processing Businesses, which include a natural gas gathering system and related compression facilities, the Rattlesnake Treating Plant, a 50-percent equity interest in Coyote Gas Treating, L.L.C. which owns the Coyote natural gas treating facility, and the remaining interests in the Chaco cryogenic natural gas processing plant we did not already own, all of which are located in the San Juan Basin of northwest New Mexico and southwestern Colorado;
- 100 percent of the Typhoon Oil Pipeline assets located in the Deepwater Trend area of the Gulf of Mexico. Typhoon Oil was placed in service in July 2001 and provides transportation of oil produced from the Typhoon field for delivery to a platform in Green Canyon Block 19 with onshore access through various oil pipelines;
- 100 percent of the Typhoon Gas Pipeline, which was placed in service in August 2001. Typhoon Gas is also located in the Deepwater Trend area of the Gulf of Mexico. The pipeline gathers natural gas from the Typhoon field for redelivery into El Paso Corporation's ANR Patterson System; and
- 100 percent of the Coastal Liquids Partners' NGL Business, consisting of an integrated set of NGL assets that stretch from the Mexico border near McAllen, Texas, to Houston, Texas. This business includes a fractionation facility near Houston, Texas; a truck-loading terminal near McAllen, Texas, and leased underground NGL storage facilities.

We purchased the San Juan assets for $782 million, $764 million after adjustments for capital expenditures and actual working capital acquired. During 2003, the total purchase price and net assets acquired decreased $2.4 million due to post-closing purchase price adjustments related to natural gas imbalances, NGL in-kind reserves and well loss reserves. We financed the purchase of these assets with net proceeds from an offering of $200 million of 10⅝% Senior Subordinated Notes due 2012; borrowings of $237.5 million under our senior secured acquisition term loan; our issuance, to El Paso Corporation, of 10,937,500 of our Series C units valued at $32 per unit or $350 million; and currently available funds. We acquired the San Juan assets because they are strategically located in active supply development areas and are supported by long-term contracts that provide us with growing and reliable cash flows consistent with our stated growth strategy.

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

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

- We no longer receive fixed fee revenue of $0.134/Dth for natural gas processed; rather, from a majority of our customers, we receive a processing fee of an in-kind portion of the NGL produced from the natural gas processed. We then sell these NGL and, accordingly, our processing revenues are affected by changes in the price of NGL.
- We no longer receive revenue for leasing the Chaco plant to El Paso Field Services.
- We no longer recognize amortization expense relating to our investment in processing agreement, which we terminated upon completing the acquisition. This decrease in amortization expense is offset by additional depreciation expense associated with the acquired assets.

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

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at November 27, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

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

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

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

	2002	2001
	(In thousands, except per unit amounts)	
Operating revenues	$627,191	$427,942
Income from continuing operations	$ 88,902	$ 77,219
Income allocated to common unitholders from continuing operations	$ 25,738	$ 16,687
Basic and diluted net income per unit from continuing operations	$ 0.60	$ 0.43

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

EPN Holding Assets

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

- The Waha natural gas gathering and treating system and the Carlsbad natural gas gathering system which are generally located in the Permian Basin region of Texas and New Mexico.
- A 50 percent undivided interest in the Channel Pipeline System, an intrastate natural gas transmission system located along the Gulf Coast of Texas.
- The TPC Offshore pipeline system, a collection of natural gas gathering and transmission assets located offshore of Matagorda Bay, Texas, including the Oyster Lake and MILSP Condensate Separation and Stabilization facilities and other undivided interests in smaller pipelines.
- GulfTerra Texas Pipeline, L.P. which owned, among other assets, (i) the GulfTerra Texas intrastate pipeline system, (ii) the TGP natural gas lateral pipelines, (iii) the leased natural gas storage facilities located in Wharton County, Texas generally known as the Wilson Storage facility, (iv) an 80 percent undivided interest in the East Texas 36 inch pipeline, (v) a 50 percent undivided interest in the West Texas 30 inch pipeline, (vi) a 50 percent undivided interest in the North Texas 36 inch pipeline, (vii) the McMullen County natural gas gathering system, (viii) the Hidalgo County natural gas gathering system, (ix) a 22 percent undivided interest in the Bethel-Howard pipeline, and (x) a 75 percent undivided interest in the Longhorn pipeline.
- El Paso Hub Services L.L.C. which owned certain contract rights and parcels of real property located in Texas.
- 100 percent of the outstanding joint venture interest in Warwink Gathering and Treating Company which owned, among other assets, the Warwink natural gas gathering system located in the Permian Basin region of Texas and New Mexico.

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

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

- $420 million of cash;
- $119 million of assumed short-term indebtedness payable to El Paso Corporation, which we subsequently repaid;
- $6 million in common units; and
- $190 million in assets, comprised of our Prince TLP and our nine percent overriding royalty interest in the Prince field (see discussion below).

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

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

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at April 8, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

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

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

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

	2002	2001
	(In thousands, except per unit amounts)	
Operating revenues	$540,154	$538,095
Income from continuing operations	$114,517	$ 81,022
Income allocated to common unitholders from continuing operations	$ 56,020	$ 38,874
Basic and diluted net income per unit from continuing operations	$ 1.31	$ 1.13

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

Prince Assets

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

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

Deepwater Holdings L.L.C. and Chaco Transaction

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

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

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

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

GTM Texas (formerly EPN Texas)

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

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

	2001
	(In thousands, except per unit amounts)
Operating revenues	$269,681
Operating income	$101,406
Net income allocated to limited partners	$ 39,157
Basic and diluted net income per unit	$ 1.14

Gulf of Mexico Assets

In accordance with an FTC order related to El Paso Corporation's merger with The Coastal Corporation, we, along with Deepwater Holdings, agreed to sell several of our offshore Gulf of Mexico assets to third parties in January 2001. Total consideration received for these assets was approximately $163 million consisting of approximately $109 million for the assets we sold and approximately $54 million for the assets Deepwater Holdings sold. The offshore assets sold include interests in Stingray, UTOS, Nautilus, Manta Ray Offshore, Nemo, Tarpon, and the Green Canyon pipeline assets, as well as interests in two offshore platforms and one dehydration facility. We recognized net losses from the asset sales of approximately $12 million, and Deepwater Holdings recognized losses of approximately $21 million. Our share of Deepwater Holdings' losses was approximately $14 million, which has been reflected in earnings from unconsolidated affiliates in the accompanying 2001 consolidated statement of income.

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

3. Investments in Unconsolidated Affiliates

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

	As of or for the Year Ended December 31, 2003				
	Coyote	Deepwater Gateway[(c)]	Cameron Highway[(c)]	Poseidon	Total
			(In thousands)		
End of period ownership interest	50%	50%	50%	36%	
Operating results data:					
Operating revenues	$ 7,200	$ —	$ —	$ 41,293	
Other income	7	47	37	56	
Operating expenses	(355)	—	—	(3,694)	
Depreciation	(1,381)	—	—	(8,316)	
Other expenses	(736)	(31)	(171)	(6,313)	
Net income (loss)	$ 4,735	$ 16	$ (134)	$ 23,026	
Our share:					
Allocated income (loss)	$ 2,368	$ 8	$ (67)	$ 8,289	
Adjustments[(a)]	9	(8)	67	(191)	
Earnings from unconsolidated affiliate	$ 2,377	$ —	$ —	$ 8,098	$11,373[(b)]
Allocated distributions	$ 3,500	$ —	$ —	$ 8,640	$12,140
Financial position data:					
Current assets	$ 987	$ 8,271	$ 53,644	$ 98,937	
Noncurrent assets	31,897	230,825	266,554	218,893	
Current liabilities	34,784	18,294	26,332	91,146	
Noncurrent liabilities	—	155,000	125,000	123,000	

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

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

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

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

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

The Cameron Highway oil pipeline system project is expected to be funded with 37 percent equity, or $169 million through capital contributions from us and Valero, the two Cameron Highway partners, which contributions have already been made, and 63 percent debt through a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes. See Note 6 for additional discussion of the project loan facility. As of December 31, 2003, Cameron Highway has spent approximately $256 million (of which $85 million constituted equity contributions by us) related to this pipeline, which is in the construction stage. We and Valero are obligated to make additional capital contributions to Cameron Highway if and to the extent that the construction costs for the pipeline exceed Cameron Highway's capital resources, including initial equity contributions and proceeds from Cameron Highway's project loan facility.

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

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

	As of or for the Year Ended December 31, 2002			
	Coyote[a]	Poseidon	Deepwater Gateway[b]	Total
	(In thousands)			
End of period ownership interest	50%	36%	50%	
Operating results data:				
Operating revenues	$ 635	$ 54,261	$ —	
Other income	2	26,695	20	
Operating expenses	(38)	(4,691)	—	
Depreciation	(110)	(8,356)	—	
Other expenses	(75)	(6,923)	(234)	
Net income (loss)	$ 414	$ 60,986	$ (214)	
Our share:				
Allocated income (loss)	$ 207	$ 21,955	$ (107)	
Adjustments[c]	(13)	(8,510)	107	
Earnings from unconsolidated affiliate	$ 194	$ 13,445	$ —	$13,639
Allocated distributions	$ 2,000	$ 15,804	$ —	$17,804
Financial position data:				
Current assets	$ 1,575	$ 152,784	$ 10,745	
Noncurrent assets	33,349	218,463	110,309	
Current liabilities	34,559	119,974	28,268	
Noncurrent liabilities	—	148,000	27,000	

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

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

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

	As of or for the Year Ended December 31, 2001				
	Deepwater Holdings[(a)]	Poseidon	Divested Investments[(b)]	Other[(c)]	Total
			(In thousands)		
End of period ownership interest	100%	36%	—	50%	
Operating results data:					
Operating revenues	$ 40,933	$ 70,401	$1,982	$145	
Other income (loss)	—	394	(85)	—	
Operating expenses	(16,740)	(1,586)	(590)	(73)	
Depreciation	(8,899)	(10,552)	(953)	—	
Other (expenses) income	(5,868)	(7,668)	222	(22)	
Loss on sale of assets	(21,453)	—	—	—	
Net income (loss)	$(12,027)	$ 50,989	$ 576	$ 50	
Our share:					
Allocated income (loss)[(d)]	$ (9,925)	$ 18,356	$ 148	$ 25	
Adjustments[(e)]	—	(146)	(9)	—	
Earnings (loss) from unconsolidated affiliates	$ (9,925)	$ 18,210	$ 139	$ 25	$ 8,449
Allocated distributions	$ 12,850	$ 22,212	$ —	$ —	$35,062
Financial position data:					
Current assets		$ 91,367		$177	
Noncurrent assets		226,570		—	
Current liabilities		80,365		33	
Noncurrent liabilities		150,000		—	

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

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

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

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

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

4. Property, Plant and Equipment

Our property, plant and equipment consisted of the following:

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

(1) Includes leasehold acquisition costs with an unamortized balance of $3.2 million and $4.1 million at December 31, 2003 and 2002. One interpretation being considered relative to SFAS No. 141, *Business Combinations* and SFAS No. 142, *Goodwill and Intangible Assets* is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on our consolidated balance sheets. We will continue to include these costs in property, plant, and equipment until further guidance is provided.

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

5. Investment in Processing Agreement

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

6. Financing Transactions

Credit Facility

Our credit facility consists of two parts: the revolving credit facility maturing in 2006 and a senior secured term loan maturing in 2008. Our credit facility is guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries, as detailed in Note 16, and are collateralized with substantially all of our assets (excluding the assets of our unrestricted subsidiaries). The interest rates we are charged on our credit facility are determined at our option using one of two indices that include (i) a variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) LIBOR. The interest rate we are charged is contingent upon our leverage ratio, as defined in our credit facility, and ratings we are assigned by S&P or Moody's. The interest we are charged would increase by 0.25% if the credit ratings on our senior secured credit facility decrease or our leverage ratio decreases, or, alternatively, would decrease by 0.25% if these ratings are increased or our leverage ratio improves. Additionally, we pay commitment fees on the unused portion of our revolving credit facility at rates that vary from 0.30% to 0.50%.

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

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

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

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

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

Revolving Credit Facility

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

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

Senior Secured Term Loan

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

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

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

In connection with our acquisition of the EPN Holding assets from El Paso Corporation in April 2002, EPN Holding entered into a $560 million term credit facility with a group of commercial banks. The term credit facility provided a term loan (the GulfTerra Holding term loan) of $535 million to finance the acquisition of the EPN Holding assets, and a revolving credit facility (the GulfTerra Holding revolving credit facility) of up to $25 million to finance EPN Holding's working capital. At the time of its acquisition, EPN Holding borrowed $535 million ($531 million, net of issuance costs) under this term loan and had $25 million available under the GulfTerra Holding revolving credit facility. We used net proceeds of approximately $149 million from our April 2002 common unit offering, $0.6 million contributed by our general partner to maintain its one percent capital account balance and $225 million of the net proceeds from our May 2002 offering of 8½% Senior Subordinated Notes to reduce indebtedness under the term loan. In July 2003, we repaid the remaining $160 million balance of this term credit facility with proceeds from our issuance of $250 million 6¼% senior notes due 2010. We recognized a loss of $1.2 million related to the write-off of unamortized debt issuance costs in connection with our repayment of this facility.

Senior Secured Acquisition Term Loan

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

Argo Term Loan

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

Senior Notes

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

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

Senior Subordinated Notes

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

In March 2003, we issued $300 million in aggregate principal amount of 8½% senior subordinated notes. The interest on these notes is payable semi-annually in June and December, and the notes mature in June 2010. We used the proceeds of approximately $293.5 million, net of issuance costs, to repay $237.5 million of indebtedness under our senior secured acquisition term loan and to temporarily repay $55.5 million of the balance outstanding under our revolving credit facility. We may, at our option, prior to June 1, 2006, redeem up to 33 percent of the originally issued aggregate principal amount of these notes at a redemption price of 108.50 percent of the principal amount, and in December 2003, we redeemed $45 million under this provision (see discussion below). We may redeem all or part of the remainder of these notes at any time on or after June 1, 2007. The redemption price on that date is 104.25 percent of the principal amount, declining annually until it reaches 100 percent of the principal amount.

In November 2002, we issued $200 million in aggregate principal amount of 10⅝% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in December 2012. These notes were issued for $198 million, net of discount of $1.5 million to yield 10.75% (proceeds of $194 million, net of issuance costs) which we used to fund a portion of the acquisition of the San Juan assets. We may, at our option, prior to December 1, 2005, redeem up to 33 percent of the originally issued aggregate principal amount of the notes at a redemption price of 110.625%, and in December 2003, we redeemed $66 million under this provision (see discussion below). On or after December 1, 2007, we may redeem all or part of the remainder of these notes at 105.313% of the principal amount.

In May 2002, we issued $230 million in aggregate principal amount of 8½% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature June 2011. The Senior Subordinated Notes were issued for $234.6 million (proceeds of approximately $230 million, net of issuance costs). We used proceeds of $225 million to reduce indebtedness under our EPN Holding term credit facility and the remainder for general partnership purposes. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%, and in December 2003, we redeemed $75.9 million under this provision (see discussion below). On or after June 1, 2006, we may redeem all or part of the remainder of these notes at 104.250% of the principal amount.

In May 2001, we issued $250 million in aggregate principal amount of 8½% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in June 2011. Proceeds of approximately $243 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%, and in December 2003, we redeemed $82.5 million under this provision (see discussion below). On or after June 1, 2006, we may redeem all or part of the remainder of these notes at 104.250% of the principal amount.

In May 1999, we issued $175 million in aggregate principal amount of 10⅜% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in June 2009. Proceeds of approximately $169 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. On or after June 1, 2004, we may redeem all or part of these notes at 105.188% of the principal amount.

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

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8½%

senior subordinated notes due 2011. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. At December 31, 2003, the fair value of the swap was a liability, included in non-current liabilities, of approximately $7.4 million. The fair value of the hedged debt decreased by the same amount.

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

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

Restrictive Provisions of Senior and Senior Subordinated Notes

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

Other Credit Facilities

Poseidon

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

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

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of the $123 million outstanding under its credit facility at 3.49% through January 2004. Poseidon, under its credit facility, currently pays an additional 1.25% over the LIBOR rate resulting in an effective interest rate of 4.74% on the hedged notional amount. The interest rates Poseidon is charged on balances outstanding under its credit facility are dependent on its leverage ratio as defined in the Poseidon credit facility. Poseidon's interest rate at December 31, 2003 was LIBOR plus 1.25% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 0.25% for Base Rate loans. As of December 31, 2003, the remaining $48 million was at an average interest rate of 2.46%.

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

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

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

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

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

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

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

Deepwater Gateway

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

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

Cameron Highway

Cameron Highway Oil Pipeline Company (Cameron Highway), an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest (See Note 3 for additional discussion relating to the formation of Cameron Highway), entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, each of which fund proportionately as construction costs are incurred.

The $225 million construction loan bears interest at Cameron Highway's option at each borrowing at either (i) 2.00% over the variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) 3.00% over LIBOR. Upon completion of the construction, the construction loan will convert to a term loan maturing July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly principal payments of $8.125 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by December 31, 2006, the construction loan and senior secured notes become fully due and payable. At December 31, 2003, Cameron Highway had $69 million outstanding under the construction loan at an average interest rate of 4.21%.

The interest rate on Cameron Highway's senior secured notes is 3.25% over the rate on 10-year U.S. Treasury securities. Principal payments of $4 million are due quarterly from September 2008 through December 2011, $6 million each from March 2012 through December 2012, and $5 million each from March 2013 through the principal maturity date of December 2013. At December 31, 2003, Cameron Highway had $56 million outstanding under the notes at an average interest rate of 7.38%.

Under the terms of its project loan facility, Cameron Highway must pay each of the lenders and the senior secured noteholders commitment fees of 0.5% per year on any unused portion of such lender's or noteholder's committed funds. The project loan facility as a whole is collateralized by (1) substantially all of Cameron Highway's assets, including, upon conversion, a debt service reserve capital account, and (2) all of the equity interest in Cameron Highway. Other than the pledge of our equity interest and our construction obligations under the relevant producer agreements, as discussed in Note 3, the debt is non-recourse to us. The construction loan and senior secured notes prohibit Cameron Highway from making distributions to us until the construction loan is converted into a term loan and Cameron Highway meets certain financial requirements.

Debt Maturity Table

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

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

Interest and Debt Expense

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

	2003	2002	2001
		(In thousands)	
Interest expense incurred	$140,282	$87,522	$ 54,885
Interest capitalized	(12,452)	(5,571)	(11,755)
Net interest expense	127,830	81,951	43,130
Less: Interest expense on discontinued operations	—	891	1,588
Net interest expense on continuing operations	$127,830	$81,060	$ 41,542

Loss Due to Early Redemptions of Debt

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

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

7. Financial Instruments

Fair Value of Financial Instruments

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

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Liabilities:				
Revolving credit facility	$382.0	$382.0	$491.0	$491.0
GulfTerra Holding term credit facility	—	—	160.0	160.0
Senior secured term loan	300.0	300.0	160.0	160.0
Senior secured acquisition term loan	—	—	237.5	237.5
10 3/8% senior subordinated notes	175.0	189.9	175.0	186.4
8 1/2% senior subordinated notes[(1)]	167.5	188.4	250.0	233.1
8 1/2% senior subordinated notes[(1)]	156.6	173.4	234.3	214.5
10 5/8% senior subordinated notes	133.1	165.5	198.5	205.5
8 1/2% senior subordinated notes	255.0	290.7	—	—
6 1/4% senior notes	250.0	262.5	—	—
Non-trading derivative instruments				
Commodity swap and forward contracts	$ 9.0	$ 9.0	$ 4.7	$ 4.7
Interest rate swap	7.4	7.4	—	—

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

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

	2003			2002		
	Notional Volume			Notional Volume		
	Buy	Sell	Maximum Term in Years	Buy	Sell	Maximum Term in Years
Commodity						
Natural Gas (MDth)	85	10,980	<1	95	10,950	<1
NGL (MBbl)	—	1,644	<1	—	—	—

In July 2003, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8½%.

As of December 31, 2003, and 2002, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because the variable interest rates on these loans reprice frequently to reflect currently available interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments from prices indicated for the same or similar commodity transactions for a specific index.

Credit Risk

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

8. Partners' Capital

General

As of December 31, 2003, we had 58,404,649 common units outstanding. Common units totaling 48,020,404 are owned by the public, representing an 82.2 percent common unit interest in us. As of December 31, 2003, El Paso Corporation, through its subsidiaries, owned 10,384,245 common units, or 17.8 percent of our outstanding common units, all of our 10,937,500 Series C units and 50 percent of our one percent general partner interest.

Offering of Common Units

During 2003, we issued the following common units in public offerings:

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

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

In addition to our public offerings of common units, in October 2003, we sold 3,000,000 common units privately to Goldman Sachs in connection with their purchase of a 9.9 percent membership interest in our general partner. We used the net proceeds of $111.5 million from that private sale and the net proceeds from the other common unit public offerings to temporarily reduce amounts outstanding under our revolving credit facility, senior subordinated notes, and for general partnership purposes.

In May 2003, we issued 1,118,881 common units and 80 Series F convertible units in a registered offering to a large institutional investor for approximately $38.3 million net of offering costs. Our Series F convertible units are not listed on any securities exchange or market. Each Series F convertible unit is comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that have identical terms except for vesting and termination dates and the number of underlying common units into which they may be converted. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until the date we merge with Enterprise (subject to other defined extension rights). The Series F2 units are convertible into up to $40 million of common units. The Series F2 units terminate on March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser of (i) the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75, or (ii) the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units; (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units, assuming we had received a conversion notice on December 31, 2003 and March 2, 2004, was $40.38 and $39.40. The Series F convertible units may be converted into a maximum of 8,329,679 common units. Holders of Series F convertible units are not entitled to vote or receive distributions. The $4.1 million value associated with the Series F convertible units is included in partners' capital as a component of common units capital.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26.00 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at December 31, 2003.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million.

Any Series F convertible units outstanding at the merger date will be converted into rights to receive Enterprise common units, subject to the restrictions governing the Series F units. The number of Enterprise common units and the price per unit at conversion will be adjusted based on the 1.81 exchange ratio.

In connection with the offerings in 2003, our general partner contributed to us approximately $2.0 million of our Series B preference units and cash of $3.1 million in order to maintain its one percent general partner interest.

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

In October 2001, we completed simultaneous offerings of 5,627,070 common units, which included a public offering of 4,150,000 common units and a private offering, at the same unit price, of 1,477,070 common units to our general partner (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. We used the net cash proceeds of approximately $212 million to redeem 44,608 of our Series B preference units for their liquidation value of $50 million and to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $2.1 million in cash to us in order to satisfy its one percent contribution requirement.

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

Series B Preference Units

In August 2000, we issued 170,000 Series B preference units with a value of $170 million to acquire the Petal and Hattiesburg natural gas storage businesses. In October 2001, we redeemed 44,608 of the Series B preference units for $50 million liquidation value including accrued distributions of approximately $5.4 million, bringing the total number of units outstanding to 125,392. As of December 31, 2002, the liquidation value of the outstanding Series B preference units was approximately $158 million. In October 2003, we redeemed all 123,865 of our remaining outstanding Series B preference units for $156 million, a 7 percent discount from their liquidation value of $167 million. For this redemption, we used borrowings under our revolving credit facility. We reflected the discount as an increase to the common units capital, Series C units capital and to our general partner's capital accounts.

Series C Units

In November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of Series C units at a price of $32 per unit, $350 million in the aggregate, as part of our consideration paid for the San Juan assets. The issuance of the Series C units was an exempt transaction under Section 4(2) of the Securities Act of 1993 as a transaction not involving a public offering. The Series C units are similar to our existing common units, except that the Series C units are non-voting. After April 30, 2003, the holder of the Series C units has the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit can convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C units will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate will increase on April 30, 2004, to 110 percent of the common unit distribution rate and on April 30, 2005, to 115 percent of the common unit distribution rate. In addition, our general partner contributed $3.5 million to us in order to satisfy its one percent capital contribution requirement. The holder of the Series C units has thus far not requested a vote to convert the Series C units into common units. As part of the proposed merger with Enterprise, Enterprise will purchase from a subsidiary of El Paso Corporation all of our outstanding Series C units. These units will not be converted to Enterprise common units in the merger but rather will remain limited partnership interests in GulfTerra after the closing of the merger transaction and, as such interest, will lose their GulfTerra common unit conversion and distribution rights.

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.

Cash distributions on common units, Series C units and to our general partner are discretionary in nature and are not entitled to arrearages of minimum quarterly distributions. The following table reflects our per unit cash distributions to our common unitholders and the total distributions paid to our common unitholders, Series C unitholder and general partner during the year ended December 31, 2003:

Month Paid	Common Unit	Common Unitholders	Series C Unitholder	General Partner
	(Per unit)		(In millions)	
February	$0.675	$29.7	$ 7.4	$15.0
May	$0.675	$32.0	$ 7.4	$15.9
August	$0.700	$34.8	$ 7.7	$18.0
November	$0.710	$41.4	$ 7.8	$21.2

In January 2004, we declared a cash distribution of $0.71 per common and Series C unit, $49.3 million in aggregate, for the quarter ended December 31, 2003, which we paid on February 14, 2004. In addition, we paid our general partner $21.3 million related to its general partner interest. At the current distribution rates, our general partner receives approximately 30.2 percent of our total cash distributions for its role as our general partner.

Option Plans

In August 1998, we adopted the 1998 Omnibus Compensation Plan (Omnibus Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable officers and key management personnel. Unit options to purchase a maximum of 3 million common units may be issued pursuant to the Omnibus Plan. Unit options granted to date pursuant to the Omnibus Plan are not immediately exercisable. For unit options granted in 2001, one-half of the unit options are considered vested and exercisable one year after the date of grant and the remaining one-half of the unit options are considered vested and exercisable one year after the first anniversary of the date of grant. These unit options expire ten years from such grant date, but shall be subject to earlier termination under certain circumstances. No grants of unit options were made in 2002. During 2003, under our Omnibus Plan, we granted 17,500 unit options, 25,000 time-vested restricted units and will grant 25,000 restricted units, if certain performance targets are achieved, to employees of El Paso Field Services whose primary responsibilities are the commercial management of our assets.

In August 1998, we also adopted the 1998 Common Unit Plan for Non-Employee Directors (Director Plan), formerly the 1998 Unit Option Plan for Non-Employee Directors, to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable directors. Unit options and restricted units to purchase a maximum of 100,000 of our common units may be issued pursuant to the Director Plan. Under the Director Plan, each non-employee director receives a grant of 2,500 unit options upon initial election to the Board of Directors and an annual unit option grant of 2,000 unit options and, beginning in 2001, an annual restricted unit grant equal to the director's annual retainer (including Chairman's retainers, if applicable) divided by the fair market value of the common units on the grant date upon each re-election to the Board of Directors. Each unit option that is granted will vest immediately at the date of grant and will expire ten years from such date, but will be subject to earlier termination in the event that such non-employee director ceases to be a director of our general partner for any reason, in which case the unit options expire 36 months after such date except in the case of death, in which case the unit options expire 12 months after such date. Each director receiving a grant of restricted units is recorded as a unitholder and has all the rights of a unitholder with respect to such units, including the right to distributions on those units. The restricted units are nontransferable during the director's service on the Board of Directors. The restrictions on the restricted units will end and the director will receive one common unit for each restricted unit granted upon the director's termination. The Director Plan is administered by a management committee consisting of the Chairman of the Board of Directors of the general partner and such other senior officers of our general partner or its affiliates as the Chairman may designate. During 2003, under the Director Plan, we granted 5,226 restricted units at a fair value per unit of $36.37 and 10,500 unit options with a grant price of $35.92. Restricted units awards representing 5,429 and 4,090 were granted during 2002 and 2001 with a fair value of $32.23 and $33.00 per unit. As of December 31, 2003, 12,292 restricted units were outstanding.

We have accounted for all of these unit options and restricted units, except for the unit options issued to non-employee directors, in accordance with SFAS No. 123. Under SFAS No. 123, we report the fair value of these issuances as deferred compensation. Deferred compensation is amortized to compensation expense over the respective vesting or performance period. We have accounted for the unit options issued to the non-employee directors of our general partner's Board of Directors in accordance with APB No. 25.

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

Total unamortized deferred compensation as of December 31, 2003 and 2002 was approximately $1.5 million and $1.2 million. Our 2001 deferred compensation is fully amortized. Deferred compensation is reflected as a reduction of partners' capital and is allocated 1 percent to our general partner and 99 percent to our limited partners.

The following table summarizes activity under the Omnibus Plan and Director Plan (excluding our restricted units) as of and for the years ended December 31, 2003, 2002 and 2001.

	2003		2002		2001	
	# Units of Underlying Options	Weighted Average Exercise Price	# Units of Underlying Options	Weighted Average Exercise Price	# Units of Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of year	1,550,000	$32.17	1,614,500	$32.09	925,500	$27.15
Granted	28,000	35.08	8,000	32.23	1,016,500	35.00
Exercised	318,000	31.74	42,500	27.19	307,500	27.17
Forfeited	—	—	—	—	—	—
Canceled	144,000	34.99	30,000	34.99	20,000	27.19
Outstanding at end of year	1,116,000	$32.00	1,550,000	$32.17	1,614,500	$32.09
Options exercisable at end of year	1,106,000	$31.98	1,068,500	$30.88	606,500	$27.22

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	2003	2002	2001
Expected term in years	7	8	8
Expected volatility	28.93%	31.05%	27.50%
Expected distributions	8.88%	8.09%	9.55%
Risk-free interest rate	3.31%	3.24%	5.05%

The Black-Scholes weighted average fair value of options granted during 2003, 2002, and 2001 was $3.55, $3.71, and $2.62 per unit option, respectively.

Options outstanding as of December 31, 2003, 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	423,500	4.6	$27.13	423,500	$27.13
$27.80 to $39.72	692,500	6.9	$34.99	682,500	$34.99
$19.86 to $39.72	1,116,000	6.0	$32.00	1,106,000	$31.98

9. Earnings Per Common Unit

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

	For the Years Ended December 31,		
	2003	2002	2001
Numerator:			
Numerator for basic earnings per common unit —			
Income from continuing operations	$65,155	$34,275	$12,174
Income from discontinued operations	—	5,085	1,086
Cumulative effect of accounting change	1,340	—	—
	$66,495	$39,360	$13,260
Denominator:			
Denominator for basic earnings per common unit — weighted-average common units	49,953	42,814	34,376
Effect of dilutive securities:			
Unit options	177	—	—
Restricted units	15	—	—
Series F convertible units	86	—	—
Denominator for diluted earnings per common unit — adjusted for weighted-average common units	50,231	42,814	34,376
Basic earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	—	0.12	0.03
Cumulative effect of accounting change	0.03	—	—
	$ 1.33	$ 0.92	$ 0.38
Diluted earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	—	0.12	0.03
Cumulative effect of accounting change	0.02	—	—
	$ 1.32	$ 0.92	$ 0.38

10. Related Party Transactions

The majority of our related party transactions are with affiliates of our general partner. Under an agreement that was in place before an indirect subsidiary of El Paso Corporation purchased our general partner, an affiliate of our general partner was obligated to provide individuals to perform the day to day financial, administrative, accounting and operational functions for us. As our activities increased, the fee for such services has also increased. Further, we provide services to various El Paso Corporation subsidiaries and, in turn, they provide us services. In addition, we have acquired a number of assets from subsidiaries of El Paso Corporation. We have not had any material transactions with Enterprise, other than the merger agreement transactions, since Enterprise acquired 50 percent of our general partner.

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

	2003	2002	2001
		(In thousands)	
Revenues received from related parties:			
Natural gas pipelines and plants	$ 84,375	$159,608	$20,710
Oil and NGL Logistics	29,413	26,288	25,249
Platform services[1]	—	—	35
Natural gas storage	—	3,016	2,325
Other[1]	—	9,809	5,676
	$113,788	$198,721	$53,995
Expenses paid to related parties:			
Purchased natural gas costs	$ 33,148	$ 22,784	$34,768
Operation and maintenance	91,208	60,458	33,721
	$124,356	$ 83,242	$68,489
Reimbursements received from related parties:			
Operation and maintenance	$ 2,426	$ 2,100	$11,499

(1) In addition to revenues from continuing operations reflected above, we also received revenues from related parties in 2002 and 2001 of $6.8 million and $8.2 million for our Prince TLP and $1.0 million and $0.7 million for our 9 percent overriding royalty interest which are included in income from discontinued operations on our income statements.

For the years ended December 31, 2003, 2002 and 2001, revenues received from related parties consisted of approximately 13%, 43% and 28% of our revenue from continuing operations. Also, we have undertaken efforts to reduce our transactions with El Paso Merchant Energy North America Company (Merchant Energy) and as of June 30, 2003, we replaced all our month-to-month arrangements that were previously with Merchant Energy with similar arrangements with third parties.

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

	2003	2002	2001
		(In thousands)	
Revenues received from related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	$ 30,146	$ 92,675	$16,433
El Paso Production Company(1)	9,109	9,054	4,230
Southern Natural Gas Company	13	112	277
Tennessee Gas Pipeline Company	93	—	638
El Paso Field Services	74,427	96,880	32,382
Unconsolidated Subsidiaries			
Manta Ray Offshore(2)	—	—	35
	$113,788	$198,721	$53,995
Purchased natural gas costs paid to related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	$ 27,777	$ 19,226	$28,169
El Paso Production Company	—	2,251	6,412
Southern Natural Gas Company	143	245	187
Tennessee Gas Pipeline Company	—	70	—
El Paso Field Services	5,181	950	—
El Paso Natural Gas Company	47	42	—
	$ 33,148	$ 22,784	$34,768
Operating expenses paid to related parties:			
El Paso Corporation			
El Paso Field Services	$ 90,925	$ 60,000	$33,187
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company	283	458	534
	$ 91,208	$ 60,458	$33,721
Reimbursements received from related parties:			
Unconsolidated Subsidiaries			
Deepwater Holdings(3)	$ —	$ —	$ 9,399
Poseidon Oil Pipeline Company	2,426	2,100	2,100
	$ 2,426	$ 2,100	$11,499

(1) In addition to revenues from continuing operations from El Paso Production Company reflected above, during 2002 and 2001 we also received revenues of $7.8 million and $8.9 million from El Paso Production Company which are included in income from discontinued operations in our income statements.

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

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

Revenues received from related parties

EPN Holding Assets. Our revenues from related parties increased in 2002 as a result of our EPN Holding transaction in which we acquired gathering, transportation and processing contracts with affiliates of our general partner. For the years ended December 31, 2003 and 2002, we received $26.5 million and

$68.9 million from El Paso Merchant Energy North America Company, $19.9 million and $35.8 million from El Paso Field Services and $3.4 million and $4.0 million from El Paso Production Company.

GTM Texas. In connection with our acquisition of GTM Texas in February 2001, we entered into a 20-year fee-based transportation and fractionation agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each barrel of NGL transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. For the years ended December 31, 2003, 2002 and 2001, we received revenue of approximately $21.5 million, $26.0 million and $25.2 million related to this agreement.

Chaco processing plant. In connection with our Chaco transaction in October 2001, we entered into a 20-year fee-based processing agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each dekatherm of natural gas that we process at the Chaco plant. For the years ended December 31, 2002 and 2001, we received revenue of $29.6 million and $6.5 million related to this agreement. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. For the years ended December 31, 2002 and 2001, we received $1.8 million and $0.6 million related to this lease. As a result of the San Juan asset acquisition in November 2002, the processing agreement and the operating lease were terminated.

Storage facilities. With the April 2002 acquisition of the EPN Holding assets, we purchased contracts held by Wilson Storage with El Paso Merchant Energy North America Company. For the year ended December 31, 2002, we received approximately $2.9 million from El Paso Merchant Energy North America Company for natural gas storage fees. El Paso Merchant Energy North America Company and Tennessee Gas Pipeline Company use our Petal and Hattiesburg storage facilities from time to time. For the years ended December 31, 2002 and 2001 we received approximately $0.1 million and $1.6 million from El Paso Merchant Energy North America Company for natural gas storage fees. For the year ended December 31, 2001 we received approximately $0.7 million from Tennessee Gas Pipeline Company.

Prince TLP. In September 2001, we placed our Prince TLP in service. Prior to April 1, 2002, we received a monthly demand charge of approximately $1.9 million as well as processing fees from El Paso Production Company related to production on the Prince TLP. For the year ended December 31, 2002 and the four months ended December 31, 2001, we received $6.8 million and $8.2 million in platform revenue related to this agreement. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our Prince TLP to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

Production fields. Through 2000 we had agreed to sell substantially all of our oil and natural gas production to El Paso Merchant Energy North America Company on a month to month basis. The agreement provided fees equal to two percent of the sales value of crude oil and condensate and $0.015 per dekatherm of natural gas for marketing production. Beginning in the fourth quarter of 2000, we began selling our oil and natural gas directly to third parties and our oil and natural gas sales related to El Paso Merchant Energy North America Company were approximately $9.8 million and $5.7 million for years ended December 31, 2002 and 2001.

In October 1999, we farmed out our working interest in the Prince Field to El Paso Production Company. Under the terms of the farmout agreement, our net overriding royalty interest in the Prince Field increased to a weighted average of approximately nine percent. El Paso Production Company began production on the Prince Field in September 2001. For the year ended December 31, 2002 and the four months ended December 31, 2001, we recorded approximately $1.0 million and $0.7 million in revenues related to our overriding royalty interest in the Prince Field. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our 9 percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

GulfTerra Alabama Intrastate. Several El Paso Corporation subsidiaries buy and transport natural gas on our GulfTerra Alabama Intrastate system. For the years ended December 31, 2003, 2002 and 2001, we received approximately $0.7 million, $6.8 million and $8.3 million from El Paso Merchant Energy North America Company. For the years ended December 31, 2003, 2002 and 2001, we received approximately $4.5 million, $4.5 million and $4.2 million from El Paso Production Company. For the years ended December 31, 2003, 2002 and 2001, we received approximately $0.1 million, $0.1 million and $0.2 million from Southern Natural Gas Company.

HIOS. In October 2001, HIOS became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings. HIOS is a natural gas transmission system that has entered into interruptible transportation agreements at a non-discounted rate of $0.1244. For the years ended December 31, 2003 and 2002 and approximately three months ended December 31, 2001, we received $0.1 million, $1.4 million and $0.8 million from El Paso Merchant Energy. For the year ended December 31, 2003 and 2002, we received $1.2 million and $0.6 million from El Paso Production Company.

Texas NGL assets. In connection with our acquisition of the San Juan assets in November, 2002, we entered into a 10-year transportation agreement with El Paso Field Services. Pursuant to this agreement, beginning January 1, 2003, we receive a fee of $1.5 million per year for transportation on our NGL pipeline which extends from Corpus Christi to near Houston. In addition, we provide transportation, fractionation, storage and terminaling services to El Paso Field Services, as well as to various third parties, typically under agreements of one year term or less. We received approximately $7.5 million and $0.3 million in revenues from El Paso Field Services for the years ended December 31, 2003 and 2002.

Other. In addition to the revenues discussed above, we received $2.8 million and $2.6 million from El Paso Merchant North America and $25.6 million and $3.3 million from El Paso Field Services during 2003 and 2002 for additional gathering and processing services. The 2003 increase in revenues for El Paso Field Services was primarily as a result of higher natural gas prices and NGL volumes sold to El Paso Field Services from our Big Thicket assets.

Unconsolidated Subsidiaries. For the years ended December 31, 2001 we received approximately $0.03 million from Manta Ray Offshore Gathering as platform access and processing fees related to our South Timbalier 292 platform and our Ship Shoal 332 platform. We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso's merger with the Coastal Corporation.

Expenses paid to related parties

Cost of natural gas. Our cost of natural gas paid to related parties increased in 2003 and 2002 as a result of our San Juan assets acquisitions and our EPN Holding transaction in which we acquired contracts with affiliates of our general partner. For the year ended December 31, 2003, our San Juan assets had cost of natural gas expenses of $1.3 million from El Paso Merchant Energy North America and $0.3 million from El Paso Field Services. For the year ended December 31, 2003 and 2002, our EPN Holding assets had cost of natural gas expenses of $0.9 million and $0.3 million from El Paso Merchant Energy North America Company and $3.5 million and $0.4 million from El Paso Field Services relating to the GulfTerra Texas gathering system. GulfTerra Alabama Intrastate's purchases of natural gas include transactions with affiliates of our general partner. For the years ended December 31, 2003, 2002 and 2001, we had natural gas purchases of approximately $25.6 million, $18.9 million and $28.2 million from El Paso Merchant Energy North America Company, and $0.1 million, $0.2 million and $0.2 million from Southern Natural Gas Company and $2.3 million and $6.4 million from El Paso Production Company for the years ended December 31, 2002 and 2001. We also receive lease and throughput fees from El Paso Field Services for Hattiesburg and Anse

La Butte. For the year ended December 31, 2002 we received $0.5 million from El Paso Field Services related to these fees.

Operating Expenses. Substantially all of the individuals who perform the day-to-day financial, administrative, accounting and operational functions for us, as well as those who are responsible for directing and controlling us, are currently employed by El Paso Corporation. Under a general and administrative services agreement between subsidiaries of El Paso Corporation and us, a fee of approximately $0.8 million per month was charged to our general partner, and accordingly, to us, which is intended to approximate the amount of resources allocated by El Paso Corporation and its affiliates in providing various operational, financial, accounting and administrative services on behalf of our general partner and us. In April 2002, in connection with our acquisition of EPN Holding assets, our general and administrative services agreement was extended to December 31, 2005, and the fee increased to approximately $1.6 million per month. In November 2002, as a result of the San Juan assets acquisition, the monthly fee under our general and administrative services agreement increased by $1.3 million, bringing our total monthly fee to $2.9 million. We believe this fee approximates the actual costs incurred. Under the terms of the partnership agreement, our general partner is entitled to reimbursement of all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on our behalf, including, but not limited to, amounts payable by our general partner to El Paso Corporation under its management agreement. We are also charged for insurance and other costs paid directly by El Paso Field Services on our behalf.

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

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

	2003	2002	2001
		(In thousands)	
Basic management fee	$34,800	$18,092	$ 9,300
Operating fees[(1)]	52,924	38,422	19,821
Insurance and other costs	3,201	3,486	4,066
	$90,925	$60,000	$33,187

(1) Operating fees increased from 2002 to 2003 and from 2001 to 2002 due to the acquisition of the San Juan assets and EPN Holding assets.

Cost Reimbursements. In connection with becoming the operator of Poseidon, we entered into an operating agreement in January 2001. All fees received under contracts approximate actual costs incurred.

Acquisitions

We have purchased assets from related parties. See Note 2 for a discussion of these asset acquisitions.

Other Matters

In addition to the related party transactions discussed above, pursuant to the terms of many of the purchase and sale agreements we have entered into with various entities controlled directly or indirectly by El Paso Corporation, we have been indemnified for potential future liabilities, expenses and capital requirements above a negotiated threshold. Specifically, an indirect subsidiary of El Paso Corporation has agreed to indemnify us for specific litigation matters to the extent the ultimate resolutions of these matters result in judgments against us. For a further discussion of these matters see Note 11, Commitments and

Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We have made claims for approximately $5 million for costs incurred during the year ended December 31, 2003 as costs exceeded the established thresholds for the year ended December 31, 2003.

We have also entered into capital contribution arrangements with entities owned by El Paso Corporation, including its regulated pipelines, in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. We have an agreement to receive $6.1 million, of which $3.0 million has been collected, from ANR Pipeline Company for our Phoenix project. As of December 31, 2003, we have received $10.5 million from ANR Pipeline and $7.0 million from El Paso Field Services for the Marco Polo natural gas pipeline. In October 2003, we collected $2 million from Tennessee Gas Pipeline for our Medusa project. These amounts are reflected as a reduction in project costs. Regulated pipelines often contribute capital toward the construction costs of gathering facilities owned by others which are, or will be, connected to their pipelines. El Paso Field Services' contribution is in anticipation of additional natural gas volumes that will flow through to its onshore natural gas processing facilities.

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

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

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

In October 2003, we exchanged with El Paso Corporation its obligation to repurchase the Chaco plant from us in 19 years for additional assets (refer to Note 2). Also in October 2003, we redeemed all of our outstanding Series B preference units (refer to Note 8).

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

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

	December 31, 2003	December 31, 2002
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 4,113	$30,512
El Paso Production Company	5,991	4,346
Tennessee Gas Pipeline Company	1,350	930
El Paso Field Services[(1)]	16,571	36,071
El Paso Natural Gas Company	4,255	1,033
ANR Pipeline Company	1,600	671
Other	830	627
	34,710	74,190
Unconsolidated Subsidiaries		
Deepwater Gateway	3,939	9,636
Cameron Highway	9,302	—
Other	14	—
	13,255	9,636
Total	$47,965	$83,826

(1) The December 2002 receivable balance includes approximately $15 million of natural gas imbalances relating to our EPN Holding acquisition.

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

	December 31, 2003	December 31, 2002
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 7,523	$ 8,871
El Paso Production Company	4,069	14,518
Tennessee Gas Pipeline Company	1,278	1,319
El Paso Field Services[(1)]	13,869	55,648
El Paso Natural Gas Company	942	1,475
El Paso Corporation	6,249	4,181
Southern Natural Gas	1,871	—
Other	667	132
	36,468	86,144
Unconsolidated Subsidiaries		
Deepwater Gateway	2,268	—
Other	134	—
	2,402	—
Total	$38,870	$86,144

(1) The December 2002 payable balance includes approximately $19 million of working capital adjustments relating to our EPN Holding acquisition due to El Paso Field Services; and approximately $22 million of natural gas imbalances relating to our EPN Holding acquisition.

In connection with the sale of our Gulf of Mexico assets in January 2001, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and ending with a

$2 million payment in the first quarter of 2004. The present value of the amounts due from El Paso Corporation were classified as follows:

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

11. Commitments and Contingencies

Legal Proceedings

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

Will Price (formerly Quinque). We, along with numerous other energy companies, are named defendants in *Will Price, et al v. Gas Pipelines and Their Predecessors, et al,* filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands, and seek certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that they contend these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied on April 10, 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action petition has been filed as to heating content claims. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process natural gas in areas of western Texas related to an asset now owned by GulfTerra Holding. In May 2001, the court ruled in favor of Leapartners and entered a judgment against El Paso Field Services of approximately $10 million. El Paso Field Services filed an appeal with the Eighth Court of Appeals in El Paso, Texas. On August 15, 2003 the

Court of Appeals reversed the lower's courts calculation of past judgment interest but otherwise affirmed the judgment. A motion for a rehearing was denied. A petition for review by the Texas Supreme Court has been filed.

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

In December 2000, a 30-inch natural gas pipeline jointly owned by GulfTerra Intrastate, L.P. (GulfTerra Intrastate) now owned by GulfTerra Holding, and Houston Pipe Line Company LP ruptured in Mont Belvieu, Texas, near Baytown, resulting in substantial property damage and minor physical injury. GulfTerra Intrastate is the operator of the pipeline. Two lawsuits were filed in the state district court in Chambers County, Texas by eight plaintiffs, including two homeowners' insurers. The suits sought recovery for physical pain and suffering, mental anguish, physical impairment, medical expenses, and property damage. Houston Pipe Line Company was added as an additional defendant. In accordance with the terms of the operating agreement, GulfTerra Intrastate agreed to assume the defense of and to indemnify Houston Pipe Line Company. As of December 31, 2003, all claims have now been settled and these settlements had no impact on our financial statements.

The City of Corpus Christi, Texas (the "City") alleged that GulfTerra Texas and various Coastal entities owed it monies for past obligations under City ordinances that propose to tax GulfTerra Texas on its gross receipts from local natural gas sales for the use of street rights-of-way. Some but not all of the GulfTerra Texas pipe at issue has been using the rights-of-way since the 1960's. In addition, the City demanded that GulfTerra Texas agree to a going-forward consent agreement in order for the GulfTerra Texas pipe and Coastal pipe to have the right to remain in the City rights-of-way. In December 2003, GulfTerra Texas and the City entered into a license agreement releasing GulfTerra Texas from any past obligations and providing certain rights for the use of the City rights-of-way and City owned property. This agreement was retroactive to October 1, 2002.

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

Christopher Beverly and Gretchen Beverly, individually and on behalf of the estate of John Beverly v. GulfTerra GC, L.P., et. al. In June 2003, the plaintiffs sued us in state district court in Hardin County, Texas. The plaintiffs are the parents of John Christopher Beverly, a two year old child who died on April 15, 2002, allegedly as the result of his exposure to arsenic, benzene and other harmful chemicals in the water supply. Plaintiffs allege that several defendants responsible for that contamination, including us and BP. Our connection to the occurrences that are the basis for this suit appears to be our August 2002 purchase of certain assets from BP, including a facility in Hardin County, Texas known as the Silsbee compressor station. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between GulfTerra and BP, GulfTerra requested that BP indemnify GulfTerra for any exposure. BP has agreed to indemnify us in this matter.

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

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

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we will establish the necessary accruals. As of December 31, 2003, we had no reserves for our legal matters.

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

Environmental

Each of our operating segments is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2003, we had a reserve of approximately $21 million, included in other noncurrent liabilities, for remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. As part of the November 2002 San Juan assets acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased up to the purchase price of $766 million. We will only be indemnified for unknown liabilities for up to three years from the purchase date of this acquisition. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased. We expect to make capital expenditures for environmental matters of approximately $3 million in the aggregate for the years 2004 through 2008, primarily to comply with clean air regulations.

Shoup Air Permit Violation. On December 16, 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NoE) from the Texas Commission on Environmental Quality (TCEQ) concerning alleged Clean Air Act violations at its Shoup, Texas plant. The NoE included a draft Agreed Order assessing a penalty of $365,750 for the cited violations. The alleged violations pertained to emission limit exceedences, testing, reporting, and recordkeeping issues in 2001. While the NoE was addressed to El Paso Field Services, L.P., the substance of the NoE also concerns equipment owned at the Shoup plant by Gulfterra GC, L.P. El Paso Field Services, L.P. has responded to the NoE and is preparing to meet with the TCEQ to discuss the alleged violations and the proposed penalty.

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

Rates and Regulatory Matters

Marketing Affiliate Final Rule. In November 2003, the FERC issued a Final Rule extending its standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since our HIOS natural gas pipeline and Petal natural gas storage facility, including the 60-mile Petal natural gas pipeline, are interstate facilities as defined by the Natural Gas Act, the regulations dictate how HIOS and Petal conduct business and interact with all energy affiliates of El Paso Corporation and us.

The standards of conduct require us, absent a waiver, to functionally separate our HIOS and Petal interstate facilities from our other entities. We must dedicate employees to manage and operate our interstate facilities independently from our other Energy Affiliates. This employee group must function independently and is prohibited from communicating non-public transportation information or customer information to its Energy Affiliates. Separate office facilities and systems are necessary because of the requirement to restrict affiliate access to interstate transportation information. The Final Rule also limits the sharing of employees and offices with Energy Affiliates. The Final Rule was effective on February 9, 2004, subject to possible rehearing. On that date, each transmission provider filed with FERC and posted on the internet website a plan and scheduling for implementing this Final Rule. By June 1, 2004, written procedures implementing this Final Rule will be posted on the internet website. Requests for rehearing have been filed and are pending. At this time, we cannot predict the outcome of these requests, but at a minimum, adoption of the regulations in the form outlined in the Final Rule will place additional administrative and operational burdens on us.

Pipeline Safety Final Rule. In December 2003, the U.S. Department of Transportation issued a Final Rule requiring pipeline operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm in "high consequence areas," or HCA. The final rule requires operators to (1) perform ongoing assessments of pipeline integrity; (2) identify and characterize applicable threats to pipeline segments that could impact an HCA; (3) improve data collection, integration and analysis; (4) repair and remediate the pipeline as necessary; and (5) implement preventive and mitigative actions. The final rule incorporates the requirements of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. The Final Rule is effective as of January 14, 2004. At this time, we cannot predict the outcome of this final rule.

Other Regulatory Matters. HIOS is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a FERC approved tariff that governs its operations, terms and conditions of service, and rates. We timely filed a required rate case for HIOS on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee and changes to depreciation rates and negative salvage amortization. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. As of July 1, 2003, HIOS implemented the requested rates, subject to a refund, and has established a reserve for its estimate of its refund obligation. We will continue to review our expected refund obligation as the rate case moves through the hearing process and may increase or decrease the amounts reserved for refund obligation as our expectation changes. The FERC has conducted a hearing on this matter and an initial decision is expected to be issued in April 2004.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October of 2002. As of December 31, 2003, we had recorded fuel differences of approximately $8.2 million, which is included in other non-current assets. We are currently in discussions with the FERC as well as our customers regarding the potential collection of some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers will negatively impact our earnings.

In December 1999, GulfTerra Texas filed a petition with the FERC for approval of its rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to GulfTerra Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering service. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. GulfTerra Texas has established a reserve for refunds. In July 2002, GulfTerra Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. On February 25, 2004, the FERC issued an order denying GulfTerra Texas' request for rehearing and ordered GulfTerra Texas to file, within 45 days from the issuance of the order, a calculation of refunds and a refund plan. Additionally, the FERC ordered GulfTerra Texas to file a new rate case or justification of existing rates within three years from the date of the order.

In July 2002, Falcon Gas Storage, a competitor, also requested late intervention and rehearing of the order. Falcon asserts that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering imbalance management services. The FERC denied Falcon's late intervention on February 25, 2004. Meanwhile in December 2002, GulfTerra Texas amended its Statement of Operating Conditions to provide shippers the option of resolving daily imbalances using a third-party imbalance service provider.

Falcon filed a formal complaint in March 2003 at the Railroad Commission of Texas claiming that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering hourly imbalance management services on the GulfTerra Texas system. GulfTerra Texas filed a response specifically denying Falcon's assertions and requesting that the complaint be denied. The Railroad Commission has set their case for hearing beginning on April 13, 2004. The City Board of Public Service of San Antonio filed an intervention in opposition to Falcon's complaint.

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

Joint Ventures

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

Operating Lease

We have long-term operating lease commitments associated with the Wilson natural gas storage facility we acquired in April 2002 in connection with the EPN Holding acquisition. The term of the natural gas storage facility and base gas leases runs through January 2008, and subject to certain conditions, has one or more optional renewal periods of five years each at fair market rent at the time of renewal. We also have long-term operating lease commitments associated with two NGL storage facilities in Texas we acquired in November 2002 in connection with our San Juan asset acquisition. The leases covering these facilities expire in 2006 and 2012.

The future minimum lease payments under these operating lease commitments as of December 31, 2003 are as follows (in millions):

2004	$ 7
2005	7
2006	7
2007	6
2008	3
Thereafter	2
Total minimum lease payments	$32

Rental expense under operating leases was approximately $7.2 million and $3.9 million for the years ended December 31, 2003 and 2002. We did not have any operating leases prior to our acquisition of the EPN Holding assets in April 2002.

Other Matters

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

12. Accounting for Hedging Activities

A majority of our commodity purchases and sales, which relate to sales of oil and natural gas associated with our production operations, purchases and sales of natural gas associated with pipeline operations, sales of natural gas liquids and purchases or sales of gas associated with our processing plants and our gathering activities, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. On January 1, 2001, we adopted the provisions of SFAS No. 133, *Accounting for Derivative Instruments 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 2003, 2002 and 2001, we entered into cash flow hedges.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of $3.525 per MMBtu and pay a floating price based on the San Juan index. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative through current earnings since it did not qualify for hedge accounting under SFAS No. 133. Through the acquisition date in 2002, we recognized a $0.4 million gain in the margin of our natural gas pipelines and plants segment. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under SFAS No. 133. In February and August 2003, we entered into additional derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. As of December 31, 2003 and 2002, the fair value of these cash flow hedges was a liability of $5.8 million and $4.8 million, as the market price at those dates was higher than the hedge price. For the year ended December 31, 2003, we reclassified approximately $9.8 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. 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. In connection with our San Juan asset purchase, we also acquired the outstanding risk management positions at the Chaco plant. The value of these NGL and natural gas positions was a $0.5 million liability at the acquisition date and this amount was included in the working capital adjustments to the purchase price. These positions expired in December 2002.

In connection with our GulfTerra Alabama Intrastate operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2002 and 2003 to offset the risk of increasing natural gas prices. As of December 31, 2003, the fair value of these cash flow hedges was an asset of approximately $77 thousand. For the twelve months ended December 31, 2003, we reclassified approximately $218 thousand of unrealized accumulated gain related to these derivatives from accumulated other comprehensive income to earnings. As of December 31, 2002, the fair value of these cash flow hedges was an asset of $86 thousand. During the year ended December 31, 2002, we reclassified a loss of $1.4 million from other comprehensive income to earnings. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

Beginning in April 2002, in connection with our EPN Holding acquisition, we had swaps in place for our interest in the Indian Basin processing plant to hedge the price received for the sale of natural gas liquids. All of these hedges expired by December 31, 2002, and we recorded a loss of $163 thousand during 2002 for these cash flow hedges. We did not have any ineffectiveness in our hedging relationship since all sale prices were based on the same index as the hedge transaction.

During 2003, we entered into additional derivative financial instruments to hedge a portion of our business' exposure to changes in NGL prices during 2003 and 2004. We entered into financial swaps for 3,500 barrels per day for February through June 2003, 3,200 barrels per day for July 2003, 4,900 barrels per day for August 2003, and 6,000 barrels per day for August 2003 through September 2004. The average fixed price received was $0.49 per gallon for 2003 and will be $0.47 per gallon for 2004 while we pay a monthly average floating price based on the OPIS average price for each month. As of December 31, 2003, the fair value of these cash flow hedges was a liability of $3.3 million. For the twelve months ended December 31, 2003, we reclassified approximately $0.4 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income to earnings.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of its $185 million variable rate revolving credit facility at 3.49% over the life of the swap. Prior to April 2003, under its credit facility, Poseidon paid an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced resulting in an effective fixed interest rate of 4.74% on the hedged notional amount. This interest rate swap expired on January 9, 2004. We have recognized as a reduction in income our 36 percent share of Poseidon's realized loss on the interest rate swap of $1.7 million for the twelve months ended December 31, 2003, or $0.6 million, through our earnings from unconsolidated affiliates. As of December 31, 2002, the fair value of its interest rate swap was a liability of $1.4 million, as the market interest rate was lower than the hedge rate, resulting in accumulated other comprehensive loss of $1.4 million. We included our 36 percent share of this liability of $0.5 million as a reduction of our investment in Poseidon and as loss in accumulated other comprehensive income. Additionally, we recognized in income our 36 percent share of Poseidon's realized loss of $1.2 million for the twelve months ended December 31, 2002, or $0.4 million, through our earnings from unconsolidated affiliates.

We estimate the entire $9.0 million of unrealized losses included in accumulated other comprehensive income at December 31, 2003, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next 12 months. When our derivative financial instruments are settled, the related amount in accumulated other comprehensive income is recorded in the income statement in operating revenues, cost of natural gas and other products, or interest and debt expense, depending on the item being hedged. The effect of reclassifying these amounts to the income statement line items is recording our earnings for the period at the "hedged price" under the derivative financial instruments.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. As of December 31, 2003, the fair value of the interest rate swap was a liability included in non-current liabilities of approximately $7.4 million and the fair value of the hedged debt decreased by the same amount.

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

13. Supplemental Disclosures to the Statements of Cash Flows

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

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Interest	$135,131	$73,598	$41,020

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

	Year Ended December 31, 2003	2002	2001
		(In thousands)	
Investment in Cameron Highway Oil Pipeline Company Joint Venture	$50,836	$ —	$ —
Exchange with El Paso Corporation	23,275	—	—
Adoption of SFAS No. 143	5,726	—	—
Note receivable due to sale of Copper Eagle	3,656		
Increase in property, plant and equipment, offset by accounts payable and other noncurrent liabilities due to purchase price adjustments	377		
Acquisition of San Juan assets			
Issuance of Series C units	—	350,000	—
Investment in processing agreement classified to property, plant and equipment	—	114,412	—
Acquisition of EPN Holding assets			
Issuance of common units	—	6,000	—
Acquisition of additional 50 percent interest in Deepwater Holdings			
Working capital acquired	—	—	7,494

14. Major Customers

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

	Year Ended December 31, 2003	2002	2001
Chevron	14%	—	—
BHP Petroleum	14%	—	—
Burlington Resources	13%	—	—
El Paso Merchant Energy North America Company	—	21%	—
El Paso Field Services	—	18%	16%
Alabama Gas Corporation	—	—	14%

The 2003 major customers are a result of our San Juan asset acquisition in November 2002. Also, during 2003 we decreased our activities with affiliates of El Paso Corporation, including replacing all our month-to-month arrangements that were previously with El Paso Merchant Energy with similar arrangements with third parties. The 2002 percentage increase in revenue from El Paso Merchant Energy North America Company and El Paso Field Services is primarily due to our EPN Holding acquisition completed in 2002.

15. Business Segment Information:

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

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

The accounting policies of the individual segments are the same as those described in Note 1. We record intersegment revenues at rates that approximate market.

We use performance cash flows (which we formerly referred to as EBITDA) to evaluate the performance of our segments, determine how resources will be allocated and develop strategic plans. We define performance cash flows as earnings before interest, income taxes, depreciation and amortization and other adjustments. Historically our lenders and equity investors have viewed our performance cash flows measure as an indication of our ability to generate sufficient cash to meet debt obligations or to pay distributions, we believe that there has been a shift in investors' evaluation regarding investments in MLPs and they now put as much focus on the performance of an MLP investment as they do its ability to pay distributions. For that reason, we disclose performance cash flows as a measure of our segment's performance. We believe performance cash flows is also useful to our investors because it allows them to evaluate the effectiveness of our business segments from an operational perspective, exclusive of the costs to finance those activities, income taxes and depreciation and amortization, none of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures.

Our operating results and financial position reflect the acquisitions of the San Juan assets in November 2002, the EPN Holding assets in April 2002, the Chaco plant and the remaining 50 percent interest we did not already own in Deepwater Holdings in October 2001 and GTM Texas in February 2001. The acquisitions were accounted for as purchases and therefore operating results of these acquired entities are included prospectively from the purchase date. The following are results as of and for the periods ended December 31:

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Non-Segment Activity[1]	Total
			(In thousands)			
For the Year Ended December 31, 2003						
Revenue from external customers	$ 734,670	$ 53,850	$ 44,297	$ 20,861	$ 17,811	$ 871,489
Intersegment revenue	127	—	278	2,603	(3,008)	—
Depreciation, depletion and amortization	68,747	8,603	11,720	5,334	4,442	98,846
Earnings from unconsolidated investments	2,377	8,098	898	—	—	11,373
Performance cash flows	311,164	59,053	29,554	20,181	N/A	N/A
Assets	2,289,546	464,246	315,853	162,275	89,660	3,321,580
For the Year Ended December 31, 2002						
Revenue from external customers[2]	$ 357,581	$ 37,645	$ 28,602	$ 16,672	$ 16,890	$ 457,390
Intersegment revenue	227	—	—	9,283	(9,510)	—
Depreciation, depletion and amortization	44,479	6,481	8,503	4,205	8,458	72,126
Earnings from unconsolidated investments	194	13,445	—	—	—	13,639
Performance cash flows	167,185	43,347	16,629	29,224	N/A	N/A
Assets	2,279,955	265,900	320,662	140,758	123,621	3,130,896
For the Year Ended December 31, 2001						
Revenue from external customers	$ 100,683	$ 32,327	$ 19,373	$ 15,385	$ 25,638	$ 193,406
Intersegment revenue	381	—	—	12,620	(13,001)	—
Depreciation, depletion and amortization	12,378	5,113	5,605	4,154	7,528	34,778
Asset impairment charge	3,921	—	—	—	—	3,921
Earnings (loss) from unconsolidated investments	(9,761)	18,210	—	—	—	8,449
Performance cash flows	52,200	47,560	13,209	30,783	N/A	N/A
Assets	563,698	195,839	226,991	115,364	69,968	1,171,860

(1) Represents predominately our oil and natural gas production activities as well as intersegment eliminations. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Non-Segment Activity" column, to remove intersegment transactions.

(2) The revenue amount for our Oil and NGL Logistics segment has been reduced by $10.5 million to reflect the reclassification of Typhoon Oil Pipeline's cost of sales and other products. See Note 1, Summary of Significant Accounting Policies, for a further discussion.

A reconciliation of our segment performance cash flows to our net income is as follows:

	Years Ended December 31,		
	2003	2002	2001
Natural gas pipelines & plants	$311,164	$167,185	$ 52,200
Oil & NGL logistics	59,053	43,347	47,560
Natural gas storage	29,554	16,629	13,209
Platform services	20,181	29,224	30,783
Segment performance cash flows	419,952	256,385	143,752
Plus: Other, nonsegment results	15,107	10,427	17,688
Earnings from unconsolidated affiliates	11,373	13,639	8,449
Income from discontinued operations	—	5,136	1,097
Cumulative effect of accounting change	1,690	—	—
Noncash hedge gain	—	411	—
Noncash earnings related to future payments from El Paso Corporation	—	—	25,404
Less: Interest and debt expense	127,830	81,060	41,542
Loss due to early redemptions of debt	36,846	2,434	—
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	—	—	3,921
Cash distributions from unconsolidated affiliates	12,140	17,804	35,062
Minority interest	917	(60)	100
Net cash payment received from El Paso Corporation	8,404	7,745	7,426
Discontinued operations of Prince facilities	—	7,201	6,561
Loss on sale of Gulf of Mexico assets	—	—	11,851
Net income	$163,139	$ 97,688	$ 55,149

16. Guarantor Financial Information

In May 2001, we purchased our general partner's 1.01 percent non-managing interest owned in twelve of our subsidiaries for $8 million. As a result of this acquisition, all our subsidiaries, but not our equity investees, are wholly owned by us. As of December 31, 2003, our credit facility is guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and is collateralized by substantially all of our assets. In addition, all of our senior notes and senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and all our subsidiaries, excluding our unrestricted subsidiaries. As of December 31, 2002, our revolving credit facility, GulfTerra Holding term credit facility, senior secured term loan and senior secured acquisition term loan are guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and are collateralized by our general and administrative services agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, as of December 31, 2002, all of our senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and all our subsidiaries excluding our unrestricted subsidiaries. The consolidating eliminations column on our condensed consolidating balance sheets below eliminates our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries. The consolidating eliminations column in our condensed consolidating statements of income and cash flows eliminates earnings from our consolidated affiliates.

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

CONDENSED CONSOLIDATING STATEMENT OF INCOME
For the Year Ended December 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ —	$ —	$171,738	$ —	$171,738
NGL sales	—	—	121,167	—	121,167
Gathering and transportation	—	815	387,962	—	388,777
Processing	—	—	52,988	—	52,988
	—	815	733,855	—	734,670
Oil and NGL logistics					
Oil sales	—	—	2,231	—	2,231
Oil transportation	—	—	26,769	—	26,769
Fractionation	—	—	22,034	—	22,034
NGL Storage	—	—	2,816	—	2,816
	—	—	53,850	—	53,850
Platform services	—	—	20,861	—	20,861
Natural gas storage	—	—	44,297	—	44,297
Other — oil and natural gas production	—	—	17,811	—	17,811
	—	815	870,674	—	871,489
Operating expenses					
Cost of natural gas and other products	—	—	287,157	—	287,157
Operation and maintenance	5,908	279	183,515	—	189,702
Depreciation, depletion and amortization	148	42	98,656	—	98,846
(Gain) loss on sale of long-lived assets	(19,000)	—	321	—	(18,679)
	(12,944)	321	569,649	—	557,026
Operating income	12,944	494	301,025	—	314,463
Earnings from consolidated affiliates	236,753	—	—	(236,753)	—
Earnings from unconsolidated affiliates	—	898	10,475	—	11,373
Minority interest expense	—	(917)	—	—	(917)
Other income	784	—	422	—	1,206
Interest and debt expense (income)	51,721	(3)	76,112	—	127,830
Loss due to early redemptions of debt	35,621	—	1,225	—	36,846
Income from continuing operations	163,139	478	234,585	(236,753)	161,449
Cumulative effect of accounting change	—	—	1,690	—	1,690
Net income	$163,139	$ 478	$236,275	$(236,753)	$163,139

CONDENSED CONSOLIDATING STATEMENT OF INCOME
Year Ended December 31, 2002

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ —	$ 30,778	$ 54,223	$ —	$ 85,001
NGL sales	—	15,050	17,928	—	32,978
Gathering and transportation	—	71,560	122,776	—	194,336
Processing	—	5,316	39,950	—	45,266
	—	122,704	234,877	—	357,581
Oil and NGL logistics					
Oil sales	—	—	108	—	108
Oil transportation	—	—	8,364	—	8,364
Fractionation	—	—	26,356	—	26,356
NGL storage	—	—	2,817	—	2,817
	—	—	37,645	—	37,645
Platform services	—	—	16,672	—	16,672
Natural gas storage	—	2,699	25,903	—	28,602
Other — oil and natural gas production	—	—	16,890	—	16,890
	—	125,403	331,987	—	457,390
Operating expenses					
Cost of natural gas and other products	—	39,280	69,539	—	108,819
Operation and maintenance	6,056	27,701	81,405	—	115,162
Depreciation, depletion and amortization	274	10,729	61,123	—	72,126
Loss on sale of long-lived assets	—	—	473	—	473
	6,330	77,710	212,540	—	296,580
Operating income	(6,330)	47,693	119,447	—	160,810
Earnings from consolidated affiliates	64,851	—	29,714	(94,565)	—
Earnings from unconsolidated affiliates	—	—	13,639	—	13,639
Minority interest income	—	60	—	—	60
Other income	1,471	5	61	—	1,537
Interest and debt expense (income)	(37,696)	22,048	96,708	—	81,060
Loss due to early redemptions of debt	—	—	2,434	—	2,434
Income from continuing operations	97,688	25,710	63,719	(94,565)	92,552
Income from discontinued operations	—	4,004	1,132	—	5,136
Net income	$ 97,688	$ 29,714	$ 64,851	$(94,565)	$ 97,688

[1] Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
Year Ended December 31, 2001

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ —	$ —	$ 59,701	$ —	$ 59,701
Gathering and transportation	—	—	33,849	—	33,849
Processing	—	—	7,133	—	7,133
	—	—	100,683	—	100,683
Oil and NGL logistics					
Oil transportation	—	—	7,082	—	7,082
Fractionation	—	—	25,245	—	25,245
	—	—	32,327	—	32,327
Platform services	—	—	15,385	—	15,385
Natural gas storage	—	—	19,373	—	19,373
Other — oil and natural gas production	—	—	25,638	—	25,638
	—	—	193,406	—	193,406
Operating expenses					
Cost of natural gas and other products	—	—	51,542	—	51,542
Operation and maintenance	(200)	—	33,479	—	33,279
Depreciation, depletion and amortization	323	—	34,455	—	34,778
Asset impairment charge	—	—	3,921	—	3,921
Loss on sale of long-lived assets	10,941	—	426	—	11,367
	11,064	—	123,823	—	134,887
Operating income (loss)	(11,064)	—	69,583	—	58,519
Earnings from consolidated affiliates	22,393	—	1,308	(23,701)	—
Earnings from unconsolidated affiliates	—	—	8,449	—	8,449
Minority interest expense	—	—	(100)	—	(100)
Other income	28,492	—	234	—	28,726
Interest and debt expense (income)	(15,328)	—	56,870	—	41,542
Income from continuing operations	55,149	—	22,604	(23,701)	54,052
Income (loss) from discontinued operations	—	1,308	(211)	—	1,097
Net income	$ 55,149	$1,308	$ 22,393	$(23,701)	$ 55,149

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

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 30,425	$ —	$ —	$ —	$ 30,425
Accounts receivable, net					
Trade	—	61	43,142	—	43,203
Unbilled trade	—	52	63,015	—	63,067
Affiliates	746,126	3,541	41,606	(743,308)	47,965
Affiliated note receivable	—	3,713	55	—	3,768
Other current assets	3,573	—	17,022	—	20,595
Total current assets	780,124	7,367	164,840	(743,308)	209,023
Property, plant and equipment, net	8,039	431	2,886,022	—	2,894,492
Intangible assets	—	—	3,401	—	3,401
Investments in unconsolidated affiliates	—	—	175,747	—	175,747
Investments in consolidated affiliates	2,108,104	—	622	(2,108,726)	—
Other noncurrent assets	199,761	—	9,155	(169,999)	38,917
Total assets	$3,096,028	$7,798	$3,239,787	$(3,022,033)	$3,321,580
Current liabilities					
Accounts payable					
Trade	$ —	$ 22	$ 113,798	$ —	$ 113,820
Affiliates	10,691	3,499	767,988	(743,308)	38,870
Accrued gas purchase costs	—	—	15,443	—	15,443
Accrued interest	10,930	—	269	—	11,199
Current maturities of senior secured term loan	3,000	—	—	—	3,000
Other current liabilities	2,601	1	24,433	—	27,035
Total current liabilities	27,222	3,522	921,931	(743,308)	209,367
Revolving credit facility	382,000	—	—	—	382,000
Senior secured term loans, less current maturities	297,000	—	—	—	297,000
Long-term debt	1,129,807	—	—	—	1,129,807
Other noncurrent liabilities	7,413	—	211,629	(169,999)	49,043
Minority interest	—	1,777	—	—	1,777
Partners' capital	1,252,586	2,499	2,106,227	(2,108,726)	1,252,586
Total liabilities and partners' capital	$3,096,028	$7,798	$3,239,787	$(3,022,033)	$3,321,580

CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2002

	Issuer	Non-guarantor Subsidiaries[(1)]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 20,777	$ —	$ 15,322	$ —	$ 36,099
Accounts receivable, net					
Trade	—	36	90,343	—	90,379
Unbilled trade	—	38	49,102	—	49,140
Affiliates	709,230	3,055	67,513	(695,972)	83,826
Other current assets	1,118	—	2,333	—	3,451
Total current assets	731,125	3,129	224,613	(695,972)	262,895
Property, plant and equipment, net	6,716	454	2,717,768	—	2,724,938
Intangible assets	—	—	3,970	—	3,970
Investments in unconsolidated affiliates	—	5,197	90,754	—	95,951
Investments in consolidated affiliates	1,787,767	—	693	(1,788,460)	—
Other noncurrent assets	205,262	—	7,879	(169,999)	43,142
Total assets	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896
Current liabilities					
Accounts payable					
Trade	$ —	$ 302	$ 119,838	$ —	$ 120,140
Affiliates	18,867	2,982	760,267	(695,972)	86,144
Accrued interest	14,221	—	807	—	15,028
Accrued gas purchase costs	—	—	6,584	—	6,584
Current maturities of senior secured term loan	5,000	—	—	—	5,000
Other current liabilities	1,645	5	19,545	—	21,195
Total current liabilities	39,733	3,289	907,041	(695,972)	254,091
Revolving credit facility	491,000	—	—	—	491,000
Senior secured term loans, less current maturities	392,500	—	160,000	—	552,500
Long-term debt	857,786	—	—	—	857,786
Other noncurrent liabilities	(1)	—	193,725	(169,999)	23,725
Minority interest	—	1,942	—	—	1,942
Partners' capital	949,852	3,549	1,784,911	(1,788,460)	949,852
Total liabilities and partners' capital	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896

(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOW
Year Ended December 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 163,139	$ 478	$ 236,275	$(236,753)	$ 163,139
Less cumulative effect of accounting change	—	—	1,690	—	1,690
Income from continuing operations	163,139	478	234,585	(236,753)	161,449
Adjustments to reconcile net income to net cash provided by (used in) operating activities					
Depreciation, depletion and amortization	148	42	98,656	—	98,846
Distributed earning of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	(898)	(10,475)	—	(11,373)
Distributions from unconsolidated affiliates	—	—	12,140	—	12,140
(Gain) loss on sale of long-lived assets	(19,000)	—	321	—	(18,679)
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	11,320	—	1,224	—	12,544
Amortization of debt issuance cost	7,118	—	380	—	7,498
Other noncash items	1,224	1,206	1,015	—	3,445
Working capital changes, net of acquisitions and non-cash transactions	3,193	(533)	(362)	—	2,298
Net cash provided by operating activities	167,142	295	337,484	(236,753)	268,168
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	—	—	(145)	—	(145)
Additions to property, plant and equipment	(2,166)	(19)	(329,834)	—	(332,019)
Proceeds from the sale and retirement of assets	69,836	—	8,075	—	77,911
Proceeds from sale of investments in unconsolidated affiliates	—	1,355	—	—	1,355
Additions to investments in unconsolidated affiliates	—	(211)	(35,325)	—	(35,536)
Repayments on note receivable	—	1,238	—	—	1,238
Cash paid for acquisitions, net of cash acquired	—	(20)	—	—	(20)
Net cash provided by (used in) investing activities	67,670	2,343	(357,229)	—	(287,216)
Cash flows from financing activities:					
Net proceeds from revolving credit facility	533,564	—	—	—	533,564
Repayments of revolving credit facility	(647,000)	—	—	—	(647,000)
Net proceeds from senior secured acquisition term loan	(23)	—	—	—	(23)
Repayment of senior secured acquisition term loan	(237,500)	—	—	—	(237,500)
Repayment of GulfTerra Holding term loan	—	—	(160,000)	—	(160,000)
Net proceeds from senior secured term loan	299,512	—	—	—	299,512
Repayment of senior secured term loan	(160,000)	—	—	—	(160,000)
Net proceeds from issuance of long-term debt	537,428	—	—	—	537,426
Repayments of long-term debt	(269,401)	—	—	—	(269,401)
Net proceeds from issuance of common units	509,008	—	—	—	509,010
Redemption of Series B preference units	(155,673)	—	—	—	(155,673)
Advances with affiliates	(399,780)	(1,396)	164,423	236,753	—
Distributions to partners	(238,397)	—	—	—	(238,397)
Distributions to minority interests	—	(1,242)	—	—	(1,242)
Contribution from general partner	3,098	—	—	—	3,098
Net cash provided by (used in) financing activities	(225,164)	(2,638)	4,423	236,753	13,374
Increase (decrease) in cash and cash equivalents	$ 9,648	$ —	$ (15,322)	$ —	(5,674)
Cash and cash equivalents at beginning of year					36,099
Cash and cash equivalents at end of year					$ 30,425

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOW
Year Ended December 31, 2002

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 97,688	$ 29,714	$ 64,851	$(94,565)	$ 97,688
Less income from discontinued operations	—	4,004	1,132	—	5,136
Income from continuing operations	97,688	25,710	63,719	(94,565)	92,552
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	274	10,730	61,122	—	72,126
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(13,639)	—	(13,639)
Distributions from unconsolidated affiliates	—	—	17,804	—	17,804
Loss on sale of long-lived assets	—	—	473	—	473
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	—	—	2,434	—	2,434
Amortization of debt issuance cost	3,449	621	373	—	4,443
Other noncash items	1,053	1,942	1,434	—	4,429
Working capital changes, net of acquisitions and non-cash transactions	16,812	(21,676)	(5,002)	—	(9,866)
Net cash provided by continuing operations	119,276	17,327	128,718	(94,565)	170,756
Net cash provided by discontinued operations	—	4,631	613	—	5,244
Net cash provided by operating activities	119,276	21,958	129,331	(94,565)	176,000
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	—	—	(1,682)	—	(1,682)
Additions to property, plant and equipment	(4,619)	(9,099)	(188,823)	—	(202,541)
Proceeds from the sale and retirement of assets	—	—	5,460	—	5,460
Additions to investments in unconsolidated affiliates	—	(1,910)	(36,365)	—	(38,275)
Cash paid for acquisitions, net of cash acquired	—	(729,000)	(435,856)	—	(1,164,856)
Net cash used in investing activities of continuing operations	(4,619)	(740,009)	(657,266)	—	(1,401,894)
Net cash provided by (used in) investing activities of discontinued operations	—	(3,523)	190,000	—	186,477
Net cash used in investing activities	(4,619)	(743,532)	(467,266)	—	(1,215,417)
Cash flows from financing activities					
Net proceeds from revolving credit facility	359,219	7,000	—	—	366,219
Repayments of revolving credit facility	(170,000)	(7,000)	—	—	(177,000)
Net proceeds from GulfTerra Holding term credit facility	—	530,529	(393)	—	530,136
Repayment of GulfTerra Holding term credit facility	—	(375,000)	—	—	(375,000)
Net proceeds from senior secured acquisition term loan	233,236	—	—	—	233,236
Net proceeds from senior secured term loan	156,530	—	—	—	156,530
Net proceeds from issuance of long-term debt	423,528	—	—	—	423,528
Repayment of Argo term loan	—	—	(95,000)	—	(95,000)
Net proceeds from issuance of common units	150,159	—	—	—	150,159
Advances with affiliates	(1,103,585)	581,601	427,419	94,565	—
Contributions from general partner	4,095	—	—	—	4,095
Distributions to partners	(154,468)	—	—	—	(154,468)
Net cash provided by (used in) financing activities of continuing operations	(101,286)	737,130	332,026	94,565	1,062,435
Net cash used in financing activities of discontinued operations	—	(3)	—	—	(3)
Net cash provided by (used in) financing activities	(101,286)	737,127	332,026	94,565	1,062,432
Increase (decrease) in cash and cash equivalents	$ 13,371	$ 15,553	$ (5,909)	$ —	23,015
Cash and cash equivalents at beginning of year					13,084
Cash and cash equivalents at end of year					$ 36,099

[1] Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
Year Ended December 31, 2001

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 55,149	$ 1,308	$ 22,393	$(23,701)	$ 55,149
Less income from discontinued operations	—	1,308	(211)	—	1,097
Income from continuing operations	55,149	—	22,604	(23,701)	54,052
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	323	—	34,455	—	34,778
Asset impairment charge	—	—	3,921	—	3,921
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(8,449)	—	(8,449)
Distributions from unconsolidated affiliates	—	—	35,062	—	35,062
Loss on sales of long-lived assets	10,941	—	426	—	11,367
Amortization of debt issuance cost	3,290	318	—	—	3,608
Other noncash items	270	—	274	—	544
Working capital changes, net of effects of acquisitions and non-cash transactions	(10,145)	385	(42,707)	—	(52,467)
Net cash provided by continuing operations	59,828	703	45,586	(23,701)	82,416
Net cash provided by discontinued operations	—	4,296	672	—	4,968
Net cash provided by operating activities	59,828	4,999	46,258	(23,701)	87,384
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	—	—	(2,018)	—	(2,018)
Additions to property, plant and equipment	(896)	—	(507,451)	—	(508,347)
Proceeds from the sale and retirement of assets	89,162	—	19,964	—	109,126
Additions to investments in unconsolidated affiliates	—	—	(1,487)	—	(1,487)
Cash paid for acquisitions, net of cash acquired	—	—	(28,414)	—	(28,414)
Net cash provided by (used in) investing activities of continuing operations	88,266	—	(519,406)	—	(431,140)
Net cash used in investing activities of discontinued operations	—	(67,367)	(1,193)	—	(68,560)
Net cash provided by (used in) investing activities	88,266	(67,367)	(520,599)	—	(499,700)
Cash flows from financing activities					
Net proceeds from revolving credit facility	559,994	—	—	—	559,994
Repayments of revolving credit facility	(581,000)	—	—	—	(581,000)
Net proceeds from issuance of long-term debt	243,032	—	—	—	243,032
Advances with affiliates	(515,198)	13,563	477,934	23,701	—
Net proceeds from issuance of common units	286,699	—	—	—	286,699
Redemption of Series B preference units	(50,000)	—	—	—	(50,000)
Contributions from general partner	2,843	—	—	—	2,843
Distributions to partners	(105,923)	—	(486)	—	(106,409)
Net cash provided by (used in) financing activities of continuing operations	(159,553)	13,563	477,448	23,701	355,159
Net cash provided by financing activities of discontinued operations	—	49,960	—	—	49,960
Net cash provided by (used in) financing activities	(159,553)	63,523	477,448	23,701	405,119
Increase (decrease) 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.

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

General

This footnote discusses our oil and natural gas production activities for the year 2001. The years 2003 and 2002 are not presented since these operations are not a significant part of our business as defined by SFAS No. 69, *Disclosures About Oil and Gas Producing Activities*, and we do not expect it to become significant in the future.

Oil and Natural Gas Reserves

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

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

	Oil/Condensate MBbls[(1)]	Natural Gas MMcf[(1)]
Proved reserves — December 31, 2000	1,201	11,500
Revision of previous estimates	1,852	5,913
Production[(2)]	(345)	(4,172)
Proved reserves — December 31, 2001	2,708	13,241
Proved developed reserves December 31, 2001[(2)]	2,350	10,384

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

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

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

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

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

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

Future Net Cash Flows

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

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

	December 31, 2001
	(In thousands)
Future cash inflows[1]	$ 80,603
Future production costs[2]	(19,252)
Future development costs	(10,530)
Future net cash flows	50,821
Annual discount at 10% rate	(11,761)
Standardized measure of discounted future net cash flows	$ 39,060

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

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

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

	Proved Developed	Proved Undeveloped	Total
		(In thousands)	
Undiscounted estimated future net cash flows from proved reserves before income taxes	$40,518	$10,303	$50,821
Present value of estimated future net cash flows from proved reserves before income taxes, discounted at 10%	$31,003	$ 8,057	$39,060

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

	2001
	(In thousands)
Beginning of year	$ 77,706
Sales and transfers of oil and natural gas produced, net of production costs	(34,834)
Net changes in prices and production costs	(55,657)
Extensions, discoveries and improved recovery, less related costs	—
Oil and natural gas development costs incurred during the year	2,018
Changes in estimated future development costs	535
Revisions of previous quantity estimates	38,090
Accretion of discount	7,771
Changes in production rates, timing and other	3,431
End of year	$ 39,060

Development, Exploration, and Acquisition Expenditures

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

	2001
	(In thousands)
Development costs	$2,018
Capitalized interest	—
Total capital expenditures	$2,018

In the year presented, we elected not to incur any costs to develop our proved undeveloped reserves.

Capitalized Costs

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

	2001
	(In thousands)
Oil and natural gas properties	
Proved properties	$ 54,609
Wells, equipment, and related facilities	104,766
	159,375
Less accumulated depreciation, depletion and amortization	108,307
	$ 51,068

Results of operations

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

	2001
	(In thousands)
Natural gas sales	$18,248
Oil, condensate, and liquid sales	8,062
Total operating revenues	26,310
Production costs[1]	16,367
Depreciation, depletion and amortization	7,567
Results of operations from producing activities	$ 2,376

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

18. Supplemental Quarterly Financial Information:

	Quarter Ended (Unaudited)				
	March 31	June 30	September 30	December 31	Year
	(In thousands, except per unit data)				
2003					
Operating revenues[1]	$230,095	$237,031	$213,831	$190,532	$871,489
Operating income	75,107	77,886	92,079	69,391	314,463
Income from continuing operations	40,525	49,297	60,213	11,414	161,449
Cumulative effect of accounting change	1,690	—	—	—	1,690
Net income	42,215	49,297	60,213	11,414	163,139
Income allocation					
Series B unitholders	$ 3,876	$ 3,898	$ 4,018	$ —	$ 11,792
General partner					
Income from continuing operations	$ 14,860	$ 15,856	$ 18,031	$ 20,667	$ 69,414
Cumulative effect of accounting change	17	—	—	—	17
	$ 14,877	$ 15,856	$ 18,031	$ 20,667	$ 69,431
Common unitholders					
Income from continuing operations	$ 17,454	$ 24,160	$ 31,337	$ (7,796)	$ 65,155
Cumulative effect of accounting change	1,340	—	—	—	1,340
	$ 18,794	$ 24,160	$ 31,337	$ (7,796)	$ 66,495
Series C unitholders					
Income from continuing operations	$ 4,335	$ 5,383	$ 6,827	$ (1,457)	$ 15,088
Cumulative effect of accounting change	333	—	—	—	333
	$ 4,668	$ 5,383	$ 6,827	$ (1,457)	$ 15,421
Basic earnings per common unit					
Income from continuing operations	$ 0.40	$ 0.50	$ 0.63	$ (0.14)	$ 1.30
Cumulative effect of accounting change	0.03	—	—	—	0.03
Net income	$ 0.43	$ 0.50	$ 0.63	$ (0.14)	$ 1.33
Diluted earnings per common unit[2]					
Income from continuing operations	$ 0.40	$ 0.50	$ 0.62	$ (0.14)	$ 1.30
Cumulative effect of accounting change	0.03	—	—	—	0.02
Net income	$ 0.43	$ 0.50	$ 0.62	$ (0.14)	$ 1.32
Distributions declared and paid per common unit	$ 0.675	$ 0.675	$ 0.700	$ 0.710	$ 2.760
Basic weighted average number of common units outstanding	44,104	48,005	50,072	57,562	49,953
Diluted weighted average number of common units outstanding	44,104	48,476	50,385	57,855	50,231

(1) Since November 2002, when we acquired the Typhoon Oil Pipeline, we have recognized revenue attributable to it using the "gross" method, which means we record as "revenues" all oil that we purchase from our customers at an index price less an amount that compensates us for our service and we record as "cost of oil" that same oil which we resell to those customers at the index price. We believe that a "net" presentation is more appropriate than a "gross" presentation and is consistent with how we evaluate the performance of the Typhoon Oil Pipeline. Based on our review of the accounting literature, we believe that generally accepted accounting principles permit us to use the "net" method, and accordingly we have presented the results of Typhoon Oil "net" for all periods. To reflect this reclassification, operating revenues have been reduced by $48.8 million, $73.1 million and $69.8 million for the quarters ended March 31, June 30 and September 30 of 2003. This change does not affect operating income or net income.

(2) As a result of the loss allocated to our common unitholders during the quarter ended December 31, 2003, the basic and diluted earnings per common units are the same.

	Quarter Ended (Unaudited)				
	March 31	June 30	September 30	December 31	Year
	(In thousands, except per unit data)				
2002					
Operating revenues[(1)]	$ 61,544	$120,489	$122,249	$153,108	$457,390
Operating income	22,712	45,777	41,936	50,385	160,810
Income from continuing operations	14,741	28,685	23,346	25,780	92,552
Income from discontinued operations	4,385	60	456	235	5,136
Net income	19,126	28,745	23,802	26,015	97,688
Income allocation					
Series B unitholders	$ 3,552	$ 3,630	$ 3,693	$ 3,813	$ 14,688
General partner					
Income from continuing operations	$ 8,691	$ 10,799	$ 10,755	$ 11,837	$ 42,082
Income from discontinued operations	44	—	5	2	51
	$ 8,735	$ 10,799	$ 10,760	$ 11,839	$ 42,133
Common unitholders					
Income from continuing operations	$ 2,498	$ 14,256	$ 8,898	$ 8,623	$ 34,275
Income from discontinued operations	4,341	60	451	233	5,085
	$ 6,839	$ 14,316	$ 9,349	$ 8,856	$ 39,360
Series C unitholders	$ —	$ —	$ —	$ 1,507	$ 1,507
Basic and diluted earnings per common unit					
Income from continuing operations	$ 0.06	$ 0.33	$ 0.20	$ 0.21	$ 0.80
Income from discontinued operations	0.11	—	0.01	—	0.12
Net income	$ 0.17	$ 0.33	$ 0.21	$ 0.21	$ 0.92
Distributions declared and paid per common unit	$ 0.625	$ 0.650	$ 0.650	$ 0.675	$ 2.600
Weighted average number of common units outstanding	39,941	42,842	44,130	44,069	42,814

(1) Operating revenues for the quarter ended December 31, 2002, have been reduced by $10.5 million to reflect the reclassification of Typhoon Oil Pipeline's cost of oil.

REPORT OF INDEPENDENT AUDITORS

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

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)1. on page 172 present fairly, in all material respects, the financial position of GulfTerra Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)2. presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

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

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

PricewaterhouseCoopers LLP

Houston, Texas
March 12, 2004

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

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

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

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

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

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

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

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

General

We and our general partner utilize the employees of and management services provided by El Paso Corporation and its affiliates under our general and administrative agreement. We reimburse our general partner and its affiliates for reasonable general and administrative expenses, and other reasonable expenses, incurred by them.

As a result of recent clarifications in the insider trading rules, and in particular, the promulgation of Rule 10b5-1, we have revised our insider trading policy to allow certain officers and directors to establish pre-established trading plans. Rule 10b5-1 allows certain officers and directors to establish written programs that permit an independent person who is not aware of insider information at the time of the trade to execute pre-established trades of our securities for the officer or directors according to fixed parameters. As of March 10, 2004, no officer or director has established a trading plan. However, we will disclose the existence of any trading plan in compliance with Rule 10b5-1 in future filings with the Securities and Exchange Commission (SEC).

Governance Matters

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals, and to maintain the trust and confidence of investors, employees, suppliers, business partners and other stakeholders. The following is a brief discussion of certain existing practices and recent developments that we have undertaken to maintain strong governance principles.

Independence of Board Members. A key element for strong governance is independent members of the board of directors. Our general partner is committed to having at least a majority of its Board of Directors be comprised of independent directors. Pursuant to the NYSE listing standards, a director will be considered independent if the board determines that he or she does not have a material relationship with our general partner or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with our general partner or us). Based on the foregoing, the Board has affirmatively determined that Michael B. Bracy, H. Douglas Church, W. Matt Ralls and Kenneth L. Smalley are "independent" directors under the NYSE rules. Thus, the Board of Directors of our general partner has a majority (67 percent) of independent directors.

Heightened Independence for Audit and Conflicts Committee Members. As required by the Sarbanes-Oxley Act of 2002 and SEC rules that would direct national securities exchanges and associations to prohibit the listing of securities of a public company if members of its audit committee did not satisfy a heightened independence standard. In order to meet this standard, a member of an audit committee may not receive any consulting fee, advisory fee or other compensation from the public company other than fees for service as a director or committee member, and may not be considered an affiliate of the public company. Based on the foregoing criteria, the Board of Directors of our general partner has affirmatively determined that all members of its Audit and Conflicts Committee satisfy this heightened independence requirement.

Audit Committee Financial Expert. An audit committee plays an important role in promoting effective corporate governance, and it is imperative that members of an audit committee have requisite financial literacy and expertise. All members of the Audit and Conflicts Committee meet the financial literacy required by the NYSE rules. In addition, as required by the Sarbanes-Oxley Act of 2002, the SEC rules require that public companies disclose whether or not its audit committee has an "audit committee financial expert" as a member. An "audit committee financial expert" is defined as a person who, based on his or her experience, satisfies all of the following attributes:

- An understanding of generally accepted accounting principles and financial statements.
- An ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves.
- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and level of complexity of issues that can reasonably be expected to be raised by GulfTerra Energy Partners' financial statements, or experience actively supervising one or more persons engaged in such activities.
- An understanding of internal controls and procedures for financial reporting.
- An understanding of audit committee functions.

Based on the information presented, the Board of Directors has affirmatively determined that Michael B. Bracy satisfies the definition of "audit committee financial expert."

Executive Sessions of Board. The Board of Directors of our general partner holds regular executive sessions in which non-management board members meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "Presiding Director," who is responsible for leading and facilitating such executive sessions. For 2003, the Presiding Director was Michael B. Bracy, the Chairman of the Audit and Conflicts Committee. For 2004, the Presiding Director is Kenneth L. Smalley, the Chairman of the Governance and Compensation Committee. Each calendar year the position of Presiding Director shall rotate among the committee chairs of the Audit and Conflicts Committee and the Governance and Compensation Committee.

Committees of Board of Directors. The Board of Directors of our general partner has two committees: the Audit and Conflicts Committee and the Governance and Compensation Committee.

Governance Guidelines. Governance guidelines, together with committee charters, provide the framework for the effective governance. The Board of Directors of our general partner has adopted the GulfTerra Energy Partners Governance Guidelines addressing several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of committees, the conduct and frequency of board and committee meetings, management succession, director access to management and outside advisors, director compensation, director orientation and continuing education, and annual self-evaluation of the board. The Board of Directors of our general partner recognizes that effective governance is an on-going process, and thus, the Board will review the GulfTerra Energy Partners Governance Guidelines annually or more often as deemed necessary.

Code of Ethics. We have adopted a code of ethics, the "Code of Business Conduct," that applies to all of our directors and employees, including its Chief Executive Officer, Chief Financial Officer and senior financial and accounting officers. In addition to other matters, the Code of Business Conduct establishes policies to deter wrongdoing and to promote honest and ethical conduct, including ethical handling of actual or apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting violations of the code. A copy of our Code of Business Conduct is available on our website at *www.gulfterra.com*. We intend to post any waivers to or amendments of our Code of Business Conduct which are required by applicable law to be disclosed on our website at *www.gulfterra.com.*

Web Access. We provide access through our website to current information relating to governance, including a copy of each Board committee charter, the Code of Business Conduct, the GulfTerra Energy Partners Governance Guidelines and other matters impacting our governance principles. We also provide access through our website to all filings submitted by GulfTerra Energy Partners with the SEC. The company's website is *www.gulfterra.com* and access to this information is free of any charge to the user.

Directors and Executive Officers of our General Partner

The following table sets forth certain information as of March 10, 2004, 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 managing member, GulfTerra GP 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.

On January 28, 2003, the Board of Directors of our general partner established a Governance and Compensation Committee, determined that all three members of the audit and conflicts committee (Messrs. Bracy, Church and Smalley), satisfy the independence requirements for audit committee eligibility and determined that Mr. Bracy is an audit committee financial expert as determined by the SEC rules.

There is no family relationship among any of the executive officers or directors of our general partner, and, other than described herein, no arrangement or understanding exists between any executive officer and any other person pursuant to which he was or is to be selected as an officer.

Name	Age	Position(s)
Robert G. Phillips	49	Director, Chairman and Chief Executive Officer
James H. Lytal	46	Director and President
William G. Manias	42	Vice President and Chief Financial Officer
Michael B. Bracy	62	Director
H. Douglas Church	66	Director
W. Matt Ralls	54	Director
Kenneth L. Smalley	74	Director

Mr. Phillips has served as a Director of our general partner since August 1998. He has served as Chief Executive Officer for us and our general partner since November 1999 and as Chairman since October 2002. He served as Executive Vice President from August 1998 to October 1999. Mr. Phillips has served as President of El Paso Field Services Company since June 1997. He served as President of El Paso Energy Resources Company from December 1996 to June 1997, President of El Paso Field Services Company from April 1996 to December 1996 and Senior Vice President of El Paso from September 1995 to April 1996. For more than five years prior, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc.

Mr. Lytal has served as a Director of our general partner since August 1994 and as our President and the President of our general partner since July 1995. He served as Senior Vice President for us and our general partner from August 1994 to June 1995. Prior to joining us, Mr. Lytal served in various capacities in the oil and gas exploration and production and gas pipeline industries with United Gas Pipeline Company, Texas Oil and Gas, Inc. and American Pipeline Company.

Mr. Manias assumed the position of Chief Financial Officer in February 2004. Mr. Manias was most recently Vice President, Business Development and Strategic Planning for El Paso Field Services Company, a subsidiary of El Paso Corporation. Prior to that position, he served as Vice President of Global Power and Pipeline Investment Banking for J.P. Morgan Securities.

Mr. Bracy has served as a Director of our general partner since October 1998 and is an audit committee financial expert as determined under the Securities and Exchange Commission rules. From January 1993 to August 1997, Mr. Bracy served as a Director, Executive Vice President and Chief Financial Officer of NorAm Energy Corp. For nine years prior, Mr. Bracy served in various executive capacities with NorAm. Mr. Bracy is a member of the Board of Directors of Itron, Inc., which is not related to GulfTerra Energy Partners, L.P.

Mr. Church has served as a Director of our general partner since January 1999. From January 1994 to December 1998, Mr. Church served as the Senior Vice President, Transmission, Engineering and Environmental for a subsidiary of Duke Energy Corporation, Texas Eastern Transmission Company. For thirty-two years prior, Mr. Church served in various engineering and operating capacities with Texas Eastern

Transmission Company, Panhandle Eastern Corporation and Transwestern Pipeline Company. Mr. Church is a past member of the Board of Directors of Southern Gas Association and is past Chairman of Boys and Girls Country of Houston, Inc.

Mr. Ralls has served as a Director of our general partner since May 2003. Mr. Ralls is Senior Vice President and Chief Financial Officer of GlobalSantaFe, one of the largest international drilling contractors, providing offshore and land drilling services to the world's leading oil and gas companies. From 1997 to 2001, he was Global Marine's Vice President, Chief Financial Officer and Treasurer. Previously, he served as executive Vice President, Chief Financial Officer and a Director of Kelley Oil and Gas Corporation and as Vice President of Capital Markets and Corporate Development for The Meridian Resource Corporation before joining Global Marine.

Mr. Smalley has served as a Director of our general partner since June 2001. Mr. Smalley has been retired since February 1992. For more than five years prior to that date, Mr. Smalley was a Senior Vice President of Phillips Petroleum Company and President of Phillips 66 Natural Gas Company, a Phillips Petroleum Company subsidiary. Mr. Smalley served as a member of the Board of Directors of El Paso Corporation from 1992 to 2001.

Compensation of Directors

Non-employee directors of our general partner are entitled to receive an annual retainer fee of $40,000, with the chairman of any board committees entitled to receive an additional $15,000 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.

In August 1998, we adopted our Common Unit Plan for Non-Employee Directors, or our 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; an annual unit option grant of 2,000 unit options; and 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 the applicable 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 and such other senior officers of our general partner or its affiliates as the Chairman of the Board may designate.

In 1998, we granted 3,000 unit options to purchase an equal number of common units with an average exercise price of $26.17 per unit; in 1999, we granted 4,500 unit options to purchase an equal number of common units with an average exercise price of $21.58 per unit; in 2000, we granted 3,000 unit options to purchase an equal number of common units with an exercise price of $25.5625 per unit; in 2001, we granted 8,500 unit options to purchase an equal number of common units with an exercise price of $32.71 per unit and 4,090 restricted units; in 2002, we granted 8,000 unit options to purchase an equal number of common units with an exercise price of $32.23 per unit and 5,429 restricted units; and in 2003, we granted 10,500 unit options to purchase an equal number of common units with an exercise price of $35.92 per unit and 5,226 restricted units. At February 9, 2004, 47,755 units remain unissued under the Director Plan.

Audit and Conflicts Committee

The Audit and Conflicts Committee currently consists of Messrs. Bracy (chairman), Church and Smalley, each a non-employee director, and each of whom has been determined by the Board of Directors of our general partner to be "independent" (as such term is defined in the NYSE listing standards) and financially literate. With respect to the Audit function, the Committee advises the Board of Directors on matters regarding the system of internal controls and the annual audit by independent accountants and reviews our policies and practices, as well as those of our general partner. The Committee is responsible for the appointment, compensation, retention and oversight of any accounting firm engaged for the purpose of preparing or issuing an audit report or related work or performing other audit, review or attestation services for the Partnership and for the resolution of any potential disagreement between management and the Partnership's auditors regarding financial reporting. Our independent auditor reports directly to this Committee. With respect to the Conflicts function, the Committee, at the request of our general partner, reviews specific matters as to which our general partner believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by our general partner is fair and reasonable to us. The Committee evaluates, and where appropriate, negotiates proposed transactions, engages independent financial advisors and independent legal counsel to assist with its evaluation of the proposed transactions, and determines whether to approve and recommend the proposed transactions. The Charter of the Audit and Conflicts Committee is attached to this annual report as Exhibit 99.A.

Governance and Compensation Committee

The Governance and Compensation Committee was formed on January 28, 2003. The Governance and Compensation Committee currently consists of Messrs. Smalley (chairman), Bracy and Church, each a non-employee director, and each of whom has been determined by the Board of Directors of our general partner to be "independent" (as such term is defined in the NYSE listing standards). With respect to its governance function, the Committee is responsible for developing and recommending to the Board governance principles, reviewing the qualifications of candidates for Board membership, screening possible candidates for Board membership and communicating with directors regarding Board meeting format and procedures. The Committee also has responsibility for annual performance evaluations for the Board and each committee. With respect to its compensation functions, the Committee is responsible for reviewing our executive compensation strategy to ensure that management is rewarded appropriately for its contributions to our growth and profitability and that the executive compensation strategy supports organization objectives. In consultation with the Compensation Committee of El Paso Corporation, the Committee reviews annually and approves the individual elements of total compensation for our Chief Executive Officer and other executive officers and prepares a report on the factors and criteria on which their compensation was based.

Compensation Committee Interlocks and Insider Participation

During 2003, only employees of El Paso Corporation and its affiliates, through our general partner, were the individuals who worked on our matters. While compensation awarded to those individuals during 2003 was handled by El Paso Corporation, the Governance and Compensation Committee is responsible for establishing performance measures and making recommendations to El Paso Corporation concerning compensation of its employees performing duties for us in the future. The Governance and Compensation Committee has neither interlocks nor insider participation.

Compensation of our General Partner

Our general partner receives no remuneration in connection with our management other than: (i) distributions on its general and limited partner interests in us; (ii) incentive distributions on its general partner interest, as provided in the partnership agreement; and (iii) reimbursement for all direct and indirect costs and expenses incurred, all selling, general and administrative expenses incurred, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, us, including, but not limited to, the management fees paid by our general partner to a subsidiary of El Paso Corporation under its general and administrative services agreement.

Section 16(a) Beneficial Ownership Reporting Compliance

Our general partner's directors, officers and beneficial owners of more than 10 percent of a registered class of our equity securities are required to file reports of ownership and reports of changes in ownership with the SEC and the NYSE. Directors, officers and beneficial owners of more than 10 percent of our equity securities are also required to furnish us with copies of all such reports that are filed. Based on our review of copies of such forms and amendments, we believe directors, executive officers and greater than 10 percent beneficial owners complied with all filing requirements during the year ended December 31, 2003.

ITEM 11. EXECUTIVE COMPENSATION

Our executive officers and the executive officers of our general partner are compensated by El Paso Corporation and do not receive compensation from our general partner or us for their services in such capacities with the exception of awards pursuant to the Omnibus Plan discussed below. However, our general partner does make payments to a subsidiary of El Paso Corporation pursuant to its management agreement. See Item 10, Directors and Executive Officers of the Registrant — Compensation of Directors.

Omnibus Plan

In August 1998, we adopted our Omnibus Compensation Plan, or the Omnibus Plan, to provide our general partner with the ability to issue unit options, restricted units and other equity-based awards 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 $35.03 per unit pursuant to the Omnibus Plan. No grants of unit options were made in 1999, 2000 or 2002. At February 9, 2004, 1,228,500 unit options remain unissued under the Omnibus Plan.

Report From Compensation Committee Regarding Executive Compensation

As indicated above, the Governance and Compensation Committee was formed in January 2003 and consists of Messrs. Smalley (chairman), Bracy and Church, each an independent, non-employee director.

In our capacity as the Compensation Committee, we are responsible to review the executive compensation program of the Partnership to ensure that it is adequate to attract, motivate and retain competent executive personnel and that it is directly and materially related to the short-term and long-term objectives and operating performance of the Partnership. We periodically review and approve the Partnership's stated compensation strategy to ensure that management is rewarded appropriately for its contributions to Partnership growth and profitability and that the executive compensation strategy supports organization objectives.

Our responsibilities, as delegated by the Board of Directors, include the following:

- We are to ensure the executive compensation program of the Partnership is directly related to the Partnership's financial performance, and the performance of the individual executive officer;
- Administer the equity compensation under the Omnibus Plan for executive personnel;
- We shall review appropriate criteria for establishing performance targets and determining annual organization and executive performance ratings;

- We shall determine appropriate levels of executive compensation by periodically conducting a thorough competitive evaluation, reviewing proprietary and proxy information, and consulting with and receiving advice from an independent executive compensation consulting firm. We have the ultimate authority and responsibility to select, evaluate and, where appropriate, replace such independent executive compensation consulting firm, including the sole authority to approve the firm's fees and other retention terms;
- We shall ensure that the Partnership's executive compensation plans are administered in accordance with stated compensation objectives, and shall make recommendations to the Board of Directors with respect to such plans;
- We shall review the Partnership's employee benefit and compensation programs and approve management recommendations subject, where appropriate, to Board of Director approval;
- We shall consider proposals with respect to the creation of and changes to the Partnership's executive compensation program; and
- The Committee shall periodically review and make recommendations to the full Board regarding annual retainer and meeting fees for the Board of Directors and committees of the Board and shall propose the terms and awards of equity compensation for members of the Board.

During 2003, we have met and discussed the specific elements of the executive compensation program, as required above. However, because of our current relationship with El Paso Corporation and our general partner, the compensation committee of El Paso Corporation reviews and approves (as appropriate) our recommendations with respect to the individual elements of total compensation for our Chief Executive Officer and other executive officers of the Partnership.

The 2003 Compensation Committee of the Board of Directors

Kenneth L. Smalley	Michael B. Bracy	H. Douglas Church
(Chairman)	(Member)	(Member)

Summary Compensation Table

The following table sets forth information concerning the annual compensation earned by our Chief Executive Officer and each of our other executive officers:

Name/Principal Position	Fiscal Year	Annual Compensation(1) Salary ($)	Bonus ($)	Other Annual Compensation ($)	Long-Term Compensation Awards Unit Options (#)	All Other Compensation ($)
Robert G. Phillips	2003	—	—	—	—	—
Chairman of the Board and	2002	—	—	—	—	—
Chief Executive Officer	2001	—	—	—	97,500	—
James H. Lytal	2003	—	—	—	—	—
President	2002	—	—	—	—	—
	2001	—	—	—	45,000	—
D. Mark Leland	2003	—	—	—	—	—
Former Senior Vice President and	2002	—	—	—	—	—
Chief Operating Officer	2001	—	—	—	60,000	—
Keith B. Forman	2003	—	—	—	—	—
Former Chief Financial Officer	2002	—	—	—	—	—
	2001	—	—	—	15,000	—

(1) Other than awards made under our incentive arrangements, all other compensation was paid by El Paso Corporation or subsidiaries of El Paso Corporation.

Unit Option Grants

No unit options were granted to the named executives during 2003.

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 2003 AND FISCAL YEAR-END UNIT OPTION VALUES

Name	Units Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options at Fiscal Year-End (#)		Value of Unexercised In-the-Money Options at Fiscal Year-End ($) [1]	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Robert G. Phillips	—	$ —	97,500	—	$ 747,338	
James H. Lytal	—	$ —	260,000	—	$3,670,438	$—
D. Mark Leland	—	$ —	60,000	—	$ 459,900	$—
Keith B. Forman	50,000	$583,907	180,000	—	$2,667,113	$—

(1) The figures presented in these columns have been calculated based upon the difference between $42.655, the fair market value of the common units on December 31, 2003, 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, 2003.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth, as of February 29, 2004, 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, (iii) each required executive officer and (iv) all directors and executive officers of our General Partner as a group.

Title of Class	Name of Beneficial Owner	Beneficial Ownership (excluding options)[4]	Unit Options[1]	Total	Percent of Class
Common Units	General Partner/El Paso Corporation	[2]	—	[2]	[2]
Common Units	Robert G. Phillips	10,000	97,500	107,500	*
Common Units	James H. Lytal	8,016[3]	260,000	268,016	*
Common Units	D. Mark Leland	4,000	60,000	64,000	*
Common Units	Keith B. Forman	2,000	180,000	182,000	*
Common Units	William G. Manias	100	—	100	*
Common Units	Michael B. Bracy	9,885	9,500	19,385	*
Common Units	H. Douglas Church	5,624	7,500	13,124	*
Common Units	Kenneth L. Smalley	9,254	—	9,254	*
Common Units	Directors and executive officers as a group (8 persons)	48,879	614,500	663,379	1.12%

* Less than 1 percent.

(1) The Directors and executive Officers have the right to acquire common units reflected in this column within 60 days of March 1, 2004, 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 10,310,045 common units, or 17.6 percent of our outstanding common units, 10,937,500 Series C units (each of which can be converted into one common unit after an affirmative vote of the common unitholders) and our 1 percent general partner interest.

(3) The amount reflected for Mr. Lytal excludes 34 common units owned by his son, a minor.

(4) Some common units reflected in this column for certain individuals are subject to restrictions.

Changes in Control

We have entered into a merger agreement with Enterprise under which, if the merger closes, we will undergo a change of control. The proposed merger is described in more detail previously in this document.

Equity Compensation Plan Information
As of December 31, 2003

Plan Category	Number of Units to be Issued Upon Exercise of Outstanding Unit Options, Warrants, and Rights	Weighted-Average Exercise Price of Outstanding Unit Options, Warrants and Rights	Number of Units Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Units Reflected in Column (a))
	(a)	(b)	(c)
Equity compensation plans approved by common unitholders	—	—	—
Equity compensation plans not approved by common unitholders[1]	1,116,000	$32.00	1,276,255
Total	1,116,000	$32.00	N/A

(1) Included in the equity compensation plans not approved by common unitholders are the Omnibus Plan and Director Plan. These plans are described in Item 8, Financial Statements and Supplementary Data, Note 8.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Historically, we have entered into transactions with El Paso Corporation and its subsidiaries to acquire or sell assets. We have instituted specific procedures for evaluating and valuing our material transactions with El Paso Corporation and its subsidiaries. Before we consider entering into a transaction with El Paso Corporation or any of its subsidiaries, we determine whether the proposed transaction (i) would comply with the requirements under our indentures and credit agreements, (ii) would comply with substantive law, and (iii) would be fair to us and our limited partners. In addition, our general partner's board of directors utilizes an Audit and Conflicts Committee comprised solely of independent directors. This committee:

- evaluates and, where appropriate, negotiates the proposed transaction;
- engages an independent financial advisor and independent legal counsel to assist with its evaluation of the proposed transaction; and
- determines whether to reject or approve and recommend the proposed transaction.

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

We and El Paso Corporation and its subsidiaries share the time and effort of general partner personnel who provide services to us, including directors, officers and other personnel. These shared personnel include officers and directors who function as both our representatives and those of El Paso Corporation and its subsidiaries. Some of these shared officers and directors own and are awarded from time to time shares, or options to purchase shares, of El Paso Corporation; accordingly, their financial interests may not always be aligned completely with ours.

A discussion of certain agreements, arrangements and transactions between or among us, our general partner, El Paso Corporation and its subsidiaries and certain other related parties is summarized in Part II, Item 8, Financial Statements and Supplementary Data, Notes 2 and 10. Also see Item 10, Directors and Executive Officers of the Registrant.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following sets forth aggregate fees for professional services rendered for us by PricewaterhouseCoopers LLP for the years ended December 31, 2003 and 2002, (in thousands):

	December 31, 2003	December 31, 2002
Audit fees	$1,274	$1,758
Audit-Related fees	190	—
Tax fees	1,000	672
All Other fees	—	—
Total	$2,464	$2,430

The *Audit* fees represent fees for professional services rendered for the audits of our annual consolidated financial statements, reviews of the related quarterly consolidated financial statements, statutory subsidiary and equity investee audits, the review of documents filed with the Securities and Exchange Commission, consents, and the issuance of comfort letters.

The *Audit-Related* fees represent fees for internal control assessment and accounting consultations.

Tax fees represent fees for services related to tax compliance, and tax planning and advice, including services related to the preparation of unitholder annual K-1 statements.

All Other fees represent fees for services other than services reported above. No such services were rendered by PricewaterhouseCoopers LLP during the last two years.

The Audit and Conflicts Committee of our general partner has adopted a pre-approval policy for audit and non-audit services.

The Audit and Conflicts Committee has considered whether the provision of non-audit services by PricewaterhouseCoopers LLP is compatible with maintaining auditor independence and has determined that auditor independence has not been compromised.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this Annual Report:

1. Financial Statements

Our consolidated financial statements are included in Part II, Item 8 of this report:

The following financial statements of our equity investment is included on the following pages of this report:

2. Financial statement schedules and supplementary information required to be submitted.

Schedules other than that listed above are omitted because the information is not required, is not material or is otherwise included in the consolidated financial statements or notes thereto included elsewhere in this Annual Report.

SCHEDULE II

GULFTERRA ENERGY PARTNERS, L.P.

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2003, 2002 and 2001
(In thousands)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2003					
Allowance for doubtful accounts	$ 2,519	$1,500	$ —	$	$ 4,019
Environmental reserve	21,136	—	—	—	21,136
Reserve for rate refund on GulfTerra Texas	370	110	—	—	480
2002					
Allowance for doubtful accounts	$ 1,819	$ 700	$ —	$ —	$ 2,519
Environmental reserve	—	—	21,136[1]	—	21,136
Reserve for rate refund on GulfTerra Texas	—	370	—	—	370
2001					
Allowance for doubtful accounts	$ 380	$1,439	$ —	$ —	$ 1,819

(1) Our environmental reserve is for environmental liabilities assumed in our EPN Holding asset acquisition during 2002. This reserve was included in our allocation of the purchase price for the acquisition.

GULFTERRA ENERGY PARTNERS, L.P.

EXHIBIT LIST
December 31, 2003

Each exhibit identified below is filed as a part of this Annual Report. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(c) of Form 10-K.

Exhibit Number	Description
2.A	— Merger Agreement, dated as of December 15, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Company, L.L.C., Enterprise Products Partners, L.P., Enterprise Products GP, LLC, and Enterprise Products Management LLC (Exhibit 2.1 to our Current Report on Form 8-K filed December 15, 2003).
3.A	— Amended and Restated Certificate of Limited Partnership dated February 14, 2002; Amendment dated April 30, 2003 (Exhibit 3.A.1 to our 2003 First Quarter Form 10-Q); Amendment 2 dated July 25, 2003 (Exhibit 3.A.1 to our 2003 Second Quarter Form 10-Q).
3.A.1	— Conformed Certificate of Limited Partnership (Exhibit 3.A.1 to our 2003 Third Quarter Form 10-Q).
3.B	— Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Current Report on Form 8-K dated March 6, 2001); First Amendment dated November 27, 2002 (Exhibit 3.B.1 to our Current Report on Form 8-K dated December 11, 2002); Second Amendment dated May 5, 2003 (Exhibit 3.B.2 to our Current Report on Form 8-K dated May 13, 2003); Third Amendment dated May 16, 2003 (Exhibit 3.B.3 to our Current Report on Form 8-K dated May 16, 2003); Fourth Amendment dated July 23, 2003 (Exhibit 3.B.1 to our 2003 Second Quarter Form 10-Q); Fifth Amendment dated August 21, 2003 (Exhibit 3.B.1 to our Current Report on Form 8-K dated October 10, 2003).
3.B.1	— Conformed Partnership Agreement (Exhibit 3.B.2 to our Current Report on Form 8-K dated October 10, 2003).
4.D	— Indenture dated as of May 27, 1999 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4, filed on June 24, 1999, File Nos. 333-81143 through 333-81143-17); First Supplemental Indenture dated as of June 30, 1999 (Exhibit 4.2 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999 File Nos. 333-81143 through 333-81143-17); Second Supplemental Indenture dated as of July 27, 1999 (Exhibit 4.3 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999, File Nos. 333-81143 through 333-81143-17); Third Supplemental Indenture dated as of March 21, 2000, to the Indenture dated as of May 27, 1999, (Exhibit 4.7.1 to our 2000 Second Quarter Form 10-Q); Fourth Supplemental Indenture dated as of July 11, 2000 (Exhibit 4.2.1 to our 2001 Third Quarter Form 10-Q); Fifth Supplemental Indenture dated as of August 30, 2000 (Exhibit 4.2.2 to our 2001 Third Quarter Form 10-Q); Sixth Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.1 to our 2002 First Quarter Form 10-Q); Seventh Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.2 to our 2002 First Quarter Form 10-Q); Eighth Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.D.3 to our 2002 Third Quarter Form 10-Q); Ninth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.D.1 to our Current Report on Form 8-K dated March 19, 2003); Tenth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.D.2 to our Current Report on Form 8-K dated March 19, 2003); Eleventh Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.D.1 to our 2003 Second Quarter Form 10-Q.

Exhibit Number	Description
4.E	— Indenture dated as of May 17, 2001 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and the Chase Manhattan Bank, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.1 to our 2002 First Quarter Form 10-Q), Second Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.2 to our 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.E.3 to our 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.E.1 to our Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.E.2 to our Current Report on Form 8-K dated March 19, 2003); Sixth Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.E.1 to our 2003 Second Quarter Form 10-Q).
4.G	— Registration Rights Agreement by and between El Paso Corporation and GulfTerra Energy Partners, L.P. dated as of November 27, 2002 (Exhibit 4.G to our Current Report on Form 8-K dated December 11, 2002).
4.I	— Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (Exhibit 4.I to our Current Report on Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.I.1 to our Current Report on Form 8-K dated March 19, 2003); Second Supplemental Indenture dated as of June 20, 2003 (Exhibit 4.I.1 to our 2003 Second Quarter Form 10-Q).
4.K	— Indenture dated as of March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee dated as of March 24, 2003 (Exhibit 4.K to our Quarterly Report on Form 10-Q dated May 15, 2003); First Supplemental Indenture dated as of June 30, 2003 (Exhibit 4.K.1 to our 2003 Second Quarter Form 10-Q).
4.L	— Indenture dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.L to our 2003 Second Quarter Form 10-Q).
4.M	— Unitholder Agreement dated May 16, 2003 by and between GulfTerra Energy Partners, L.P. and Fletcher International, Inc. (Exhibit 4.L to our Current Report on Form 8-K filed May 19, 2003).
4.N	— Exchange and Registration Rights Agreement by and among GulfTerra Energy Company, L.L.C., GulfTerra Energy Partners, L.P. and Goldman Sachs & Co. dated as of October 2, 2003 (Exhibit 10.U to our Current Report on Form 8-K dated October 10, 2003).
10.A	— General and Administrative Services Agreement dated May 5, 2003 by and among DeepTech International Inc., GulfTerra Energy Company, L.L.C. and El Paso Field Services, L.P. (Exhibit 10.A to our Current Report on Form 8-K dated May 14, 2003).
10.L+	— 1998 Common Unit Plan for Non-Employee Directors (formerly 1998 Unit Option Plan for Non-Employee Directors) Amended and Restated effective as of April 18, 2001 (Exhibit 10.1 to our 2001 Second Quarter Form 10-Q); Amendment No. 1 dated as of May 15, 2003 (Exhibit 10.L.1 to our 2003 Second Quarter Form 10-Q).
10.M+	— 1998 Omnibus Compensation Plan, Amended and Restated, effective as of January 1, 1999 (Exhibit 10.9 to our 1998 Form 10-K); Amendment No. 1 dated as of December 1, 1999 (Exhibit 10.8.1 to our 2000 Second Quarter Form 10-Q); Amendment No. 2 dated as of May 15, 2003 (Exhibit 10.M.1 to our 2003 Second Quarter Form 10-Q).

Exhibit Number	Description
10.N	— Seventh Amended and Restated Credit Agreement dated September 26, 2003 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, as co-borrowers, JPMorgan Chase Bank, as administrative agent, and the other lenders party thereto (Exhibit 10.B to our Current Report on Form 8-K dated October 10, 2003); First Amendment dated as of December 1, 2003 (filed as Exhibit 10.B to our Current Report on Form 8-K filed December 12, 2003); Term Loan Addendum For Series B-1 Additional Term Loans dated as of December 10, 2003 (filed as Exhibit 10.B to our Current Report on Form 8-K filed December 12, 2003).
10.O	— Participation Agreement and Assignment relating to Cameron Highway Oil Pipeline Company dated as of July 10, 2003 among Valero Energy Corporation, GulfTerra Energy Partners, L.P., Cameron Highway Pipeline I, L.P. and Manta Ray Gathering Company, L.L.C. (Exhibit 10.O to our 2003 Third Quarter Form 10-Q).
10.T	— Purchase and Sale Agreement by and between GulfTerra Energy Partners, L.P. and Goldman Sachs & Co. dated as of October 2, 2003 (Exhibit 10.T to our Current Report on Form 8-K dated October 10, 2003).
10.W	— Redemption and Resolution Agreement by and among El Paso Corporation, GulfTerra Energy Partners, L.P. and El Paso New Chaco Holding, L.P. dated as of October 2, 2003 (Exhibit 10.W to our Current Report on Form 8-K dated October 10, 2003).
*21.A	— Subsidiaries of GulfTerra Energy Partners, L.P.
*23.A	— Consent of Independent Accountants.
*23.B	— Consent of Independent Petroleum Engineers.
*31.A	— Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	— Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.A	— Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.B	— Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.A	— Audit and Conflicts Committee Charter, dated February 26, 2004.

(b) Reports on Form 8-K

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

We filed a current report on Form 8-K dated December 12, 2003 to file amendments to our credit agreement and announce the redemption of certain of our senior subordinated notes.

We filed a current report on Form 8-K dated December 15, 2003 to report our proposed merger with Enterprise.

We filed a current report on Form 8-K dated February 3, 2004 to announce an overview of our merger with Enterprise.

We filed a current report on Form 8-K dated February 11, 2004 to announce William G. Manias has assumed the position of Chief Financial Officer.

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, GulfTerra Energy Partners, L.P. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the twelfth day of March 2004.

GULFTERRA ENERGY PARTNERS, L.P.

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 GulfTerra Energy Partners, L.P. and in the capacities and on the dates indicated:

Name	Title	Date
/s/ ROBERT G. PHILLIPS Robert G. Phillips	Chief Executive Officer and Chairman of the Board and Director (Principal Executive Officer)	March 12, 2004
/s/ JAMES H. LYTAL James H. Lytal	President and Director	March 12, 2004
/s/ WILLIAM G. MANIAS William G. Manias	Chief Financial Officer and Vice President (Principal Financial Officer)	March 12, 2004
/s/ KATHY A. WELCH Kathy A. Welch	Vice President and Controller (Principal Accounting Officer)	March 12, 2004
/s/ MICHAEL B. BRACY Michael B. Bracy	Director	March 12, 2004
/s/ H. DOUGLAS CHURCH H. Douglas Church	Director	March 12, 2004
/s/ KENNETH L. SMALLEY Kenneth L. Smalley	Director	March 12, 2004
/s/ W. MATT RALLS W. Matt Ralls	Director	March 12, 2004