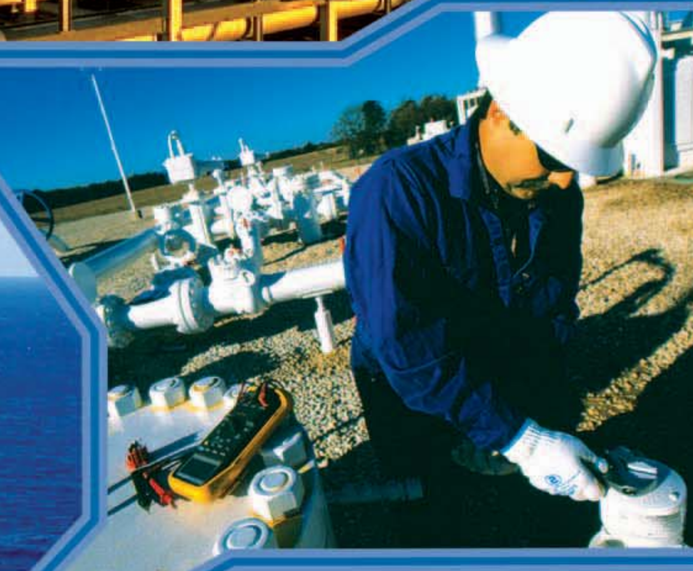
Enterprise Products Partners L.P.



Building America's Energy Infrastructure

2004 Annual Report

ENTERPRISE PRODUCTS PARTNERS L.P.

2004 ANNUAL REPORT

COMPANY OVERVIEW

Enterprise Products Partners L.P. is one of the largest publicly traded energy partnerships with an enterprise value of more than $14 billion, and is a leading North American provider of midstream energy services to producers and consumers of natural gas, natural gas liquids ("NGLs") and crude oil. Enterprise transports natural gas, NGLs and crude oil through 32,500 miles of onshore and offshore pipelines and is an industry leader in the development of midstream infrastructure in the Deepwater Trend of the Gulf of Mexico.

Enterprise has the only integrated North American midstream network complete with export services. The system links producers of natural gas, NGLs and crude oil from the largest supply basins in the United States, Canada and the Gulf of Mexico with the largest consumers and international markets.

FINANCIAL HIGHLIGHTS

Amounts in 000s except per unit amounts

	2004	2003	2002	2001	2000
Income Statement Data:					
Revenues from consolidated operations	$ 8,321,202	$ 5,346,431	$ 3,584,783	$ 3,154,369	$ 3,049,020
Gross operating margin (1)	$ 655,191	$ 410,415	$ 332,349	$ 375,944	$ 320,615
Equity in income (loss) of unconsolidated affiliates	$ 52,787	$ (13,960)	$ 35,253	$ 25,358	$ 24,119
Operating income	$ 422,994	$ 248,104	$ 194,307	$ 286,849	$ 243,734
Net Income	$ 268,261	$ 104,546	$ 95,500	$ 242,178	$ 220,506
Fully diluted earnings per unit	$ 0.87	$ 0.41	$ 0.48	$ 1.39	$ 1.32
Number of units for fully diluted calculation	266,045	206,367	176,490	170,787	164,887
Balance Sheet Data:					
Cash and cash equivalents	$ 50,713	$ 44,317	$ 22,568	$ 137,823	$ 60,409
Total assets	$ 11,315,461	$ 4,802,814	$ 4,230,272	$ 2,424,692	$ 1,951,368
Total debt	$ 4,281,236	$ 2,139,548	$ 2,246,463	$ 855,278	$ 403,847
Minority interest	$ 71,040	$ 86,356	$ 68,883	$ 11,716	$ 9,570
Combined equity/partners' equity	$ 5,328,785	$ 1,705,953	$ 1,200,904	$ 1,146,922	$ 935,959
% of net debt to total capitalization (2)	43.9%	53.9%	63.7%	38.2%	26.6%
Other Financial Data:					
Net capital expenditures	$ 146,928	$ 145,913	$ 72,135	$ 149,896	$ 243,913
Business acquisitions, net of cash received (3)	$ 724,661	$ 37,348	$ 1,620,727	$ 225,665	$ –
Investments in and advances to unconsolidated affiliates	$ 64,412	$ 471,927	$ 13,651	$ 116,220	$ 31,496
Total (4)	$ 936,001	$ 655,188	$ 1,706,513	$ 491,781	$ 275,409
EBITDA (5)	$ 623,146	$ 366,446	$ 284,820	$ 345,750	$ 291,145
Distributions from unconsolidated affiliates	$ 68,027	$ 31,882	$ 57,662	$ 45,054	$ 37,267
Cash flow from operating activities	$ 379,236	$ 419,605	$ 326,762	$ 277,576	$ 360,870
Distributable cash flow (5)	$ 541,350	$ 278,766	$ 228,194	$ 303,904	$ 292,929
Cash distributions declared per common unit (6)	$ 1.54	$ 1.47	$ 1.36	$ 1.19	$ 1.05
Annual cash distribution rate at December 31(6)	$ 1.60	$ 1.49	$ 1.38	$ 1.25	$ 1.10

(1) Gross operating margin represents operating income before depreciation and amortization, lease expense obligations retained by the Company's largest unitholder, EPCO, Inc., gain or loss from sale of assets and general and administrative expenses. Gross margin also includes the Company's equity earnings from unconsolidated affiliates.

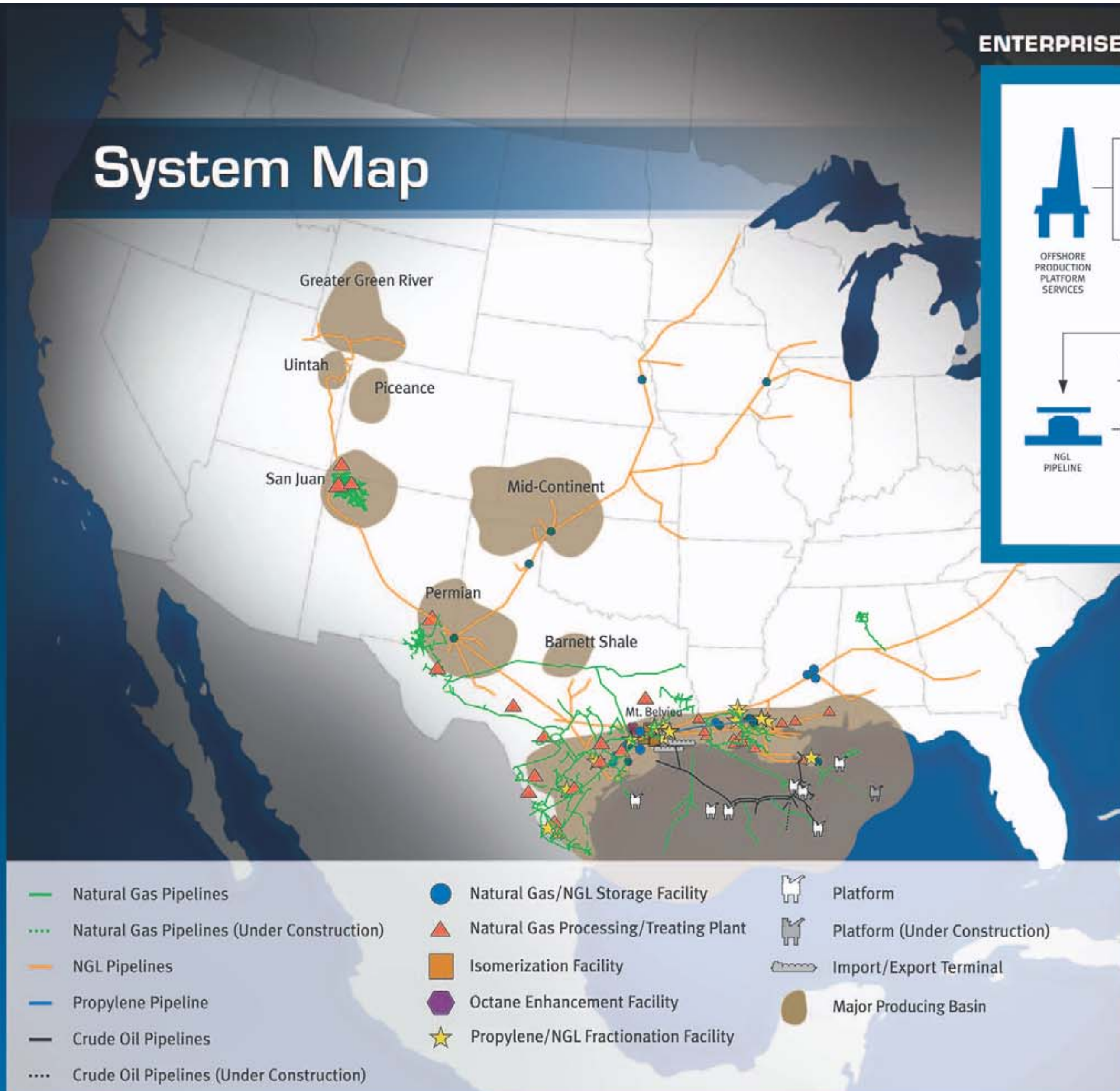
(2) Total debt less cash and cash equivalents divided by the sum of total debt, combined equity/partners' equity and minority interest less cash and cash equivalents.

(3) The amount for 2004 is net of $2,910,771 of non-cash consideration issued or granted relating to the GulfTerra merger.

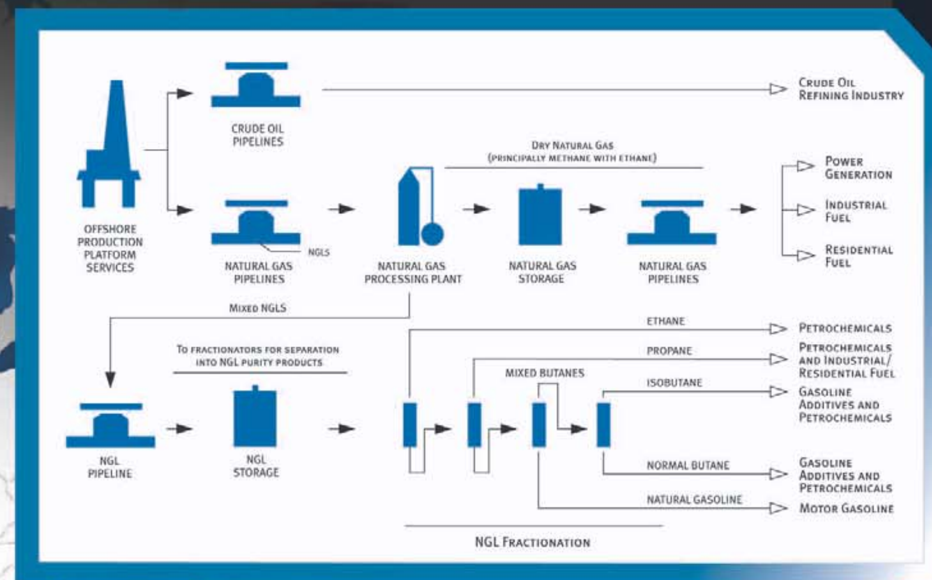
(4) Sum of net capital expenditures, business acquisitions, net of cash received and the value of non-cash consideration relating to the GulfTerra merger and investments in and advances to unconsolidated affiliates.

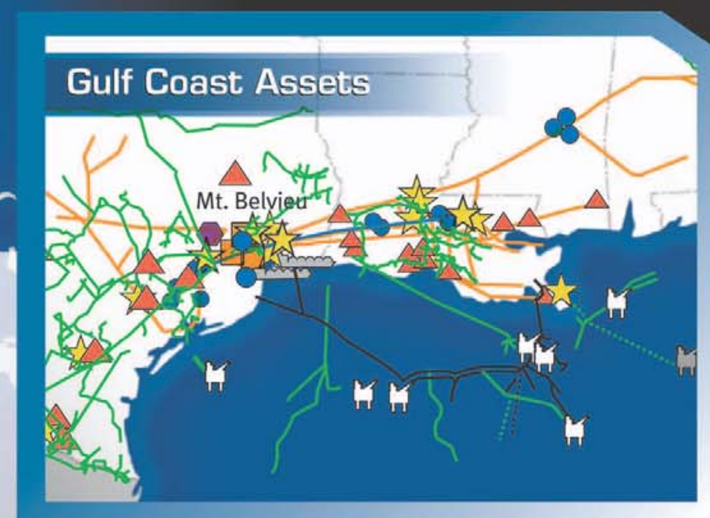
(5) For a reconciliation of GAAP financial statements to non-GAAP financial measures, see page 136.

(6) Cash distributions declared per common unit represent cash distributions declared with respect to the four fiscal quarters of each year presented. Distributions prior to May 15, 2002 have been adjusted for the 2-for-1 unit split.



ENTERPRISE MIDSTREAM ENERGY VALUE CHAIN





TO THE PARTNERS OF ENTERPRISE PRODUCTS PARTNERS L.P.

Enterprise posted another successful year in 2004. For the sixth consecutive year since our IPO in 1998, we delivered on our annual goals to partners. Our most significant achievement last year was the completion of our merger with GulfTerra Energy Partners, L.P. on September 30, 2004, which further positioned Enterprise as a leading provider of integrated midstream energy services to producers and consumers of natural gas, natural gas liquids (NGLs) and crude oil. This combination extended our value chain and enhanced our business and asset positions in most of the significant producing basins in the United States. Through the strength of our franchise and the tireless efforts of our employees, our partnership has developed a $2 billion portfolio of organic growth and acquisition opportunities that we expect to complete over the next three years. Successful execution on these opportunities will serve as the catalyst for future distribution growth and value creation for our investors.

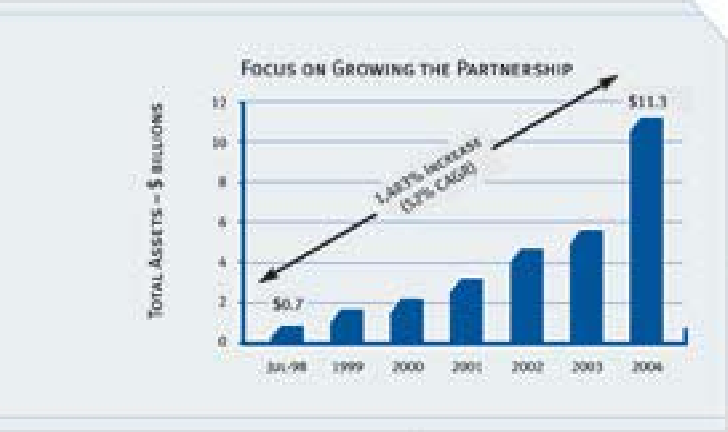
GOALS SET – GOALS ACHIEVED

Disciplined investments & increased margin from fee-based businesses

Since the beginning of 2004, we invested in or announced capital projects totaling $7.5 billion, including the $6 billion merger with GulfTerra. The majority of our capital was allocated to businesses that provide fee-based services such as natural gas gathering, transportation, storage and processing; NGL fractionation and transportation; crude oil gathering and transportation; and offshore platform services. These investments diversify and provide new sources of cash flow for our partnership.

Attractive total return to our partners

We increased our cash distribution rate to partners from $1.49 per unit at the end of 2003 to $1.60 per unit at the end of 2004, which is a 7.4% increase. Since our IPO, we have increased our cash distribution rate to partners eleven times at a compounded annual growth rate of 10%. Investors who owned Enterprise partnership units for the entire year of 2004 earned a total return including reinvested distributions of 12.7%, approximately half of which was paid in cash. Since our IPO, we have provided our investors with a total return of approximately 289% including reinvested distributions, a compounded annual return of 24%.



Likewise, investors in GulfTerra at the end of 2003 who became our partners in Enterprise as a result of the merger earned a total return including reinvested distributions of 17% for the entire year of 2004.

Conservatively financed growth

We also delivered on our objective to finance Enterprise's growth consistent with that of an investment grade company. Approximately 64% of the capital to complete the merger with GulfTerra and the related purchase of natural gas processing plants was financed with equity. At December 31, 2004, Enterprise's debt as a percentage of total capitalization was a solid 44%. During the first quarter of 2005 our debt to total capitalization further improved with our issuance of approximately $500 million of additional equity.

SUCCESSFUL MERGER AND INTEGRATION

The merger of Enterprise and GulfTerra created the largest publicly traded energy partnership in terms of market capitalization. In the six months since its completion, our confidence that this complementary merger will provide benefits to our partners for years to come has been validated. The benefits will come in the form of cost savings, diversification which should enhance the stability of the partnership's cash flow, new business opportunities and the combination of GulfTerra's backlog of higher return organic growth projects with Enterprise's strong balance sheet and lower cost of capital.

During our integration planning process, we identified approximately $140 million of annual cash savings, which significantly surpassed our initial estimates in 2003. Most of these annualized savings have already been realized. This includes approximately $55 million of yearly savings from lower cash distribution payments to the general partner as a result of adopting Enterprise's model which caps the incentive distribution rights to the general partner at 25% and eliminating GulfTerra's arrangement whereby its general partner had incentive distribution rights up to 50%. This not only provides immediate cash savings to the partnership, but it also lowers the partnership's ongoing cost of capital.

Another $45 million per year of savings is from lower interest expense. Approximately $1.9 billion of GulfTerra debt was refinanced as part of the merger process, including approximately $1.4 billion of fixed rate debt that had an average interest rate of 8.6%. In 2004, Enterprise issued $2 billion of fixed rate debt with an average interest rate of 5.14% and $846 million of equity to finance the merger, other capital investments and general partnership purposes.

We expect to save an additional $40 million per year through lower general and administrative and operating expenses. Over half of these savings were realized immediately upon completion of the merger through employee reductions and the elimination of duplicative public company costs.

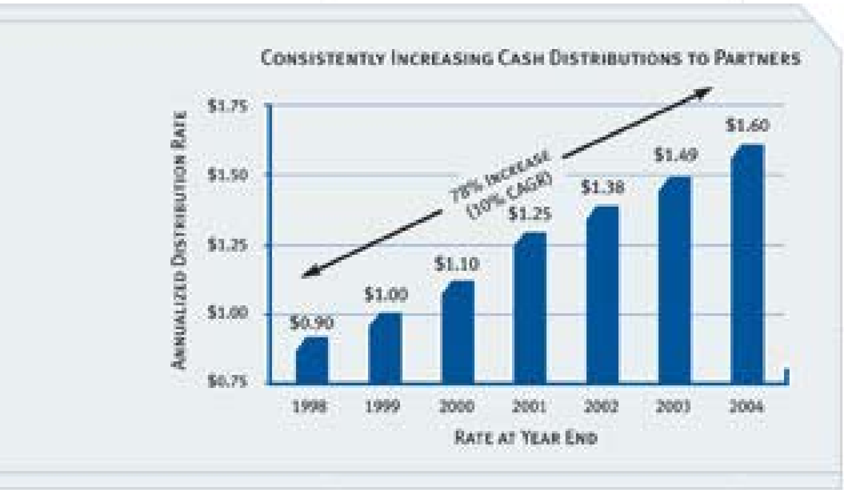
We also have a more diversified and balanced business mix as a result of the merger. Historically, Enterprise primarily provided services to consuming customers that benefited from lower energy prices while GulfTerra largely provided services to producing customers that conversely benefited from higher energy prices. Together, the partnership's predominately fee-based and diversified array of services will provide greater stability and a natural hedge to mitigate the effects of natural gas prices on our cash flow.

The potential of the combined partnership was highlighted in our financial results for the fourth quarter of 2004, the first quarter since the merger was completed. Enterprise reported record performance in several major categories including quarterly revenues of $2.9 billion, net income of $115.4 million and distributable cash flow of $197.1 million. Distributable cash flow for the quarter provided 1.2 times coverage of the distribution paid to common units and the $34 million of excess cash flow was used to fund capital investments, debt retirement and working capital needs.

We will also benefit from new streams of cash flow from a number of offshore pipeline and platform facilities that GulfTerra has been building over the last few years that have started to receive initial production and are currently ramping up volumes. These include the Cameron Highway Oil Pipeline, the Marco Polo platform and the Front Runner oil pipeline to name a few. We expect the most significant ongoing benefit from the merger will be a wealth of investment opportunities to build and acquire midstream energy assets and volume growth in some of our existing facilities to serve the growing demand for energy in the United States.

BUILDING AMERICA'S ENERGY INFRASTRUCTURE

Between 2005 and 2010 demand for crude oil and natural gas in the United States is expected to grow by 10%, or 1.9 million barrels per day, and 15%, or 8.6 billion cubic feet per day, respectively. A significant amount of that growth is expected to be supplied from incremental crude oil and natural gas production from the deepwater area of the Gulf of Mexico and the Rocky Mountain region. In addition, producing companies are continuing to develop new streams of production in many long-lived basins such as the San Juan, Fort Worth (Barnett Shale) and Permian. New investments are needed to build or expand the infrastructure required to condition and deliver these new sources of production to market. Our strong asset positions in many of these areas provide our partnership with opportunities to earn superior economic returns on investments in new facilities that "bolt on" to our existing system.



We have identified approximately $2 billion of growth opportunities to construct or acquire pipelines, platforms and processing facilities over the next few years. These projects range from the construction of pipelines and a platform project in the Gulf of Mexico to expansions of NGL and natural gas pipeline capacity in the Rocky Mountain and San Juan regions to acquiring additional interests in facilities that we currently own and operate.

Our largest capital project is the Independence Hub and Trail, a 134-mile natural gas pipeline and offshore production platform both with the capacity to handle 850 million cubic feet per day. This $665 million project, of which our share is approximately $590 million, will establish a new pipeline corridor into the eastern deepwater region of the Gulf of Mexico to facilitate production from six anchor fields and up to eleven additional fields. The project is supported by monthly fixed fees for platform services for the first five years and life of lease dedications. We expect first production into these facilities to begin in 2007.

Expected production increases in the prolific Green River, Piceance and San Juan basins in the Rocky Mountain area are driving the need for additional natural gas gathering, processing and transportation capacity and NGL pipeline capacity. We are currently working with producers to develop these types of projects.

Note: Assumes quarterly distributions reinvested.
(1) Includes BPL, EEP, KMP, NBP, TPP and PAA

COMMON GOALS

We would like to thank our approximately 2,300 employees for their day-to-day efforts and contributions to the success of our partnership. Their unmatched commitment is apparent in the recognition that Enterprise receives for safety, customer service and for being named one of America's most admired pipeline companies by Fortune.

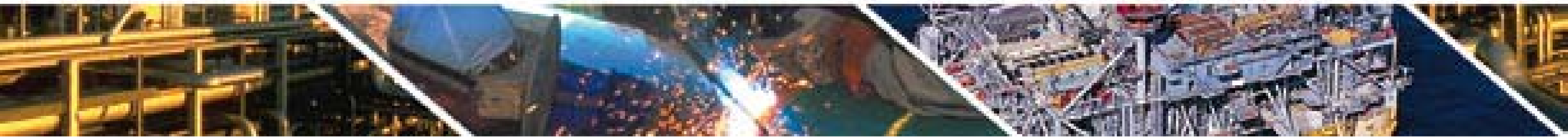
Their commitment to the partnership is also demonstrated by their investment decisions. Approximately 25% of our employees participate in our voluntary employee unit purchase program by investing a portion of their after tax payroll dollars in Enterprise's partnership units. Together, our senior management team and employees have invested over $700 million in the last three years and now own approximately 39% of our outstanding partnership units. Our interests continue to be closely aligned with those of our public partners.

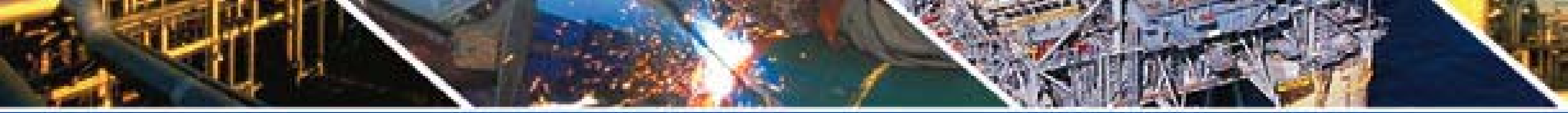
Thank you for your support during 2004 and as we continue to build partnership value in 2005.

O.S. Andras
O.S. Andras
Vice Chairman

Dan L. Duncan
Dan L. Duncan
Chairman

Robert G. Phillips
Robert G. Phillips
President and Chief Executive Officer





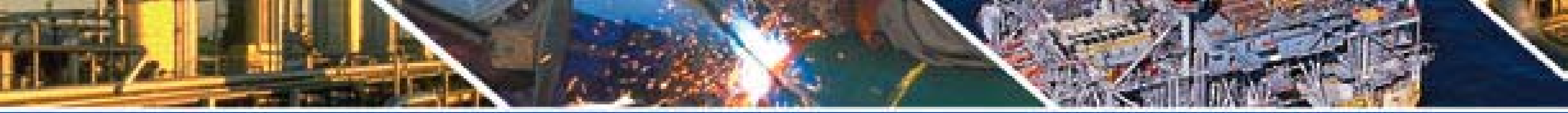
OFFSHORE

Segment Gross Operating Margin
Fourth Quarter 2004
The first quarter after the GulfTerra merger

Offshore Pipelines & Services

Enterprise, through its merger with GulfTerra, is a leader in the development of oil & gas pipeline and platform infrastructure in the Gulf of Mexico. Our natural gas and crude oil pipelines and multi-purpose hub platforms are strategically located to serve some of the most active drilling and development regions. These assets also provide the partnership with additional growth opportunities to further expand and extend our systems as producers develop the deepwater Gulf of Mexico and connect deepwater fields to our midstream value chain.

The deepwater area of the Gulf of Mexico is a focal point for new sources of crude oil and natural gas production for the United States.



Crude oil production from the deepwater has grown from 100,000 barrels per day in the early 1990s to approximately one million barrels per day ("MMBPD") in 2004. As a result, the Gulf of Mexico has surpassed Alaska as the country's largest source of domestic crude oil and condensate production. The Minerals Management Service is projecting that by 2010 crude oil production from the deepwater Gulf of Mexico will increase to 1.7 MMBPD. They are also projecting that natural gas production from the deepwater will grow from the current rate of 3.9 billion cubic feet per day ("Bcf/d") to approximately 6.0 Bcf/d over this same time period. This projected growth in oil and gas production should provide our partnership with numerous opportunities to provide infrastructure services by gathering and processing additional volumes through existing facilities and developing new pipeline and platform projects.

During 2004, producers made significant investments in developing the deepwater Gulf of Mexico with 14 new deepwater startups and 12 new discoveries. Six of the new start ups and three of the new discoveries are dedicated to our offshore facilities under life-of-reserve commitments. Approximately one million additional acres adjacent to our facilities are also dedicated to our assets. Including our onshore infrastructure, 13 of the new start ups and 7 of the new discoveries are expected to utilize some aspect of our midstream energy value chain.

We completed construction on 7 offshore infrastructure projects in 2004 including the Phoenix natural gas gathering pipeline; the Marco Polo tension leg hub platform and its supporting crude oil and natural gas gathering pipelines; the Front Runner and Tarantula crude oil gathering pipelines and the Cameron Highway Oil Pipeline System. All of these projects are now in service.

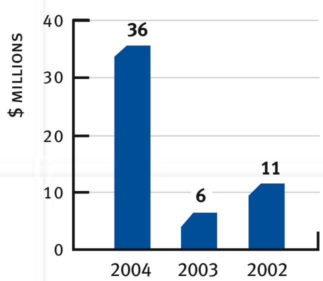
We currently plan to invest over $750 million of organic growth capital in offshore projects that should be completed and become operational over the next three years. The largest of these projects are the Constitution natural gas and crude oil gathering pipelines, which should receive initial production in 2006 and, our largest offshore project to date, the Independence Hub and Trail development, which should receive first production in 2007.

Offshore Natural Gas Pipelines

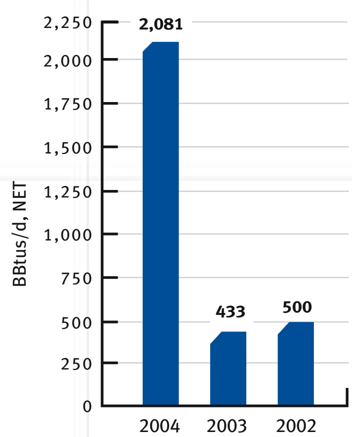
	Length In Miles	Approximate Capacity (MMcf/d, NET)	Our Ownership Interest
Manta Ray Gathering System	235	206	25.7%
High Island Offshore System (1)	204	1,800	100%
Viosca Knoll Gathering System (1)	162	1,160	100%
Green Canyon Laterals (1)	136	649	Various (2)
Anaconda Gathering System (1)	110	400	100%
Nautilus System	101	154	25.7%
East Breaks Gathering System (1)	85	400	100%
Phoenix Gathering System (1)	78	450	100%
Nemo Gathering System	24	102	33.9%
Falcon Gas Pipeline (1)	14	400	100%
Total (3)	1,149		

(1) Acquired as a result of the GulfTerra Merger on September 30, 2004.
(2) Our ownership interest in the Green Canyon Laterals ranges from 2.7% to 100%.
(3) Not included in the total above is Stingray pipeline, which is expected to be sold during the first quarter of 2005.

GROSS OPERATING MARGIN
Offshore Pipelines & Services



VOLUMES
Offshore Natural Gas Pipelines



Natural Gas Pipelines

Enterprise owns or has an interest in approximately 1,150 miles of offshore natural gas pipelines that provide gathering and transmission services for natural gas developments located in the Gulf of Mexico, primarily offshore Louisiana and Texas. These systems receive natural gas from production facilities and other pipelines through system interconnects and transport the natural gas to our processing plants and pipelines, as well as other downstream natural gas processing plants and pipelines that serve markets throughout the eastern half of the United States.

In general, these pipelines generate revenue based on transportation fees charged per unit of volume (typically in MMBtus) transported. These agreements tend to be long-term in nature, often involving life-of-reserve commitments with firm and interruptible fees. Our offshore natural gas pipeline systems do not take title to the natural gas volumes they transport; rather, the shipper retains title and the associated commodity price risk. In the fourth quarter of 2004, our offshore natural gas pipelines transported 1.8 TBtus per day.

Crude Oil Pipelines

The partnership owns interests in approximately 800 miles of offshore crude oil pipeline systems in the Gulf of Mexico. Typically, these pipelines receive oil from offshore production facilities or other pipelines and deliver the oil to either onshore locations or to other interconnecting offshore pipelines. In general, our oil pipeline systems generate revenue based on related purchase and sale agreements which together provide an implicit fee per unit of volume (typically in barrels) received. As a result, the partnership is not exposed to direct commodity price risk. A substantial portion of the revenues generated by our oil pipeline systems are attributed to production from reserves that have been committed under life-of-reserve dedications. Our offshore crude oil pipeline systems transported 138 MBPD during the fourth quarter of 2004.

Our most significant investment in offshore oil pipelines has been a 50% interest in the Cameron Highway Oil Pipeline System. An affiliate of Valero Energy Corporation is our joint partner in this approximately $500 million pipeline. This has been a very successful project for our partnership with projected reserves and initial production from anchor fields exceeding our expectations.

This 390-mile pipeline has the capacity to move up to 600 MBPD of crude oil from fields in the central and western Gulf of Mexico to refineries on the Texas Gulf Coast. Its wide loop westward across the Gulf to the larger market in Texas makes Cameron Highway an attractive pipeline for new deepwater developments in this area.

Cameron Highway is supported by life-of-reserve dedications with BP, BHP Billiton and Unocal for their production from the Holstein, Mad Dog and Atlantis fields in the Southern Green Canyon area and with Kerr McGee for its production from the Constitution and Ticonderoga fields. Additionally, Cameron Highway has contracted with Shell for the movement of its 50% share of crude oil production from the Holstein field. The Holstein field began producing in December 2004, and first production from the Mad Dog field began in January 2005. Production from the Atlantis, Constitution and Ticonderoga fields is expected to begin in 2006.

Offshore Crude Oil Pipelines

	Length In Miles	Approximate Capacity (MBPD, NET)	Our Ownership Interest
Cameron Highway Oil Pipeline	390	600	50%
Poseidon System	324	144	36%
Allegheny Oil Pipeline	43	135	100%
Marco Polo Oil Pipeline	36	120	100%
Typhoon Oil Pipeline	16	100	100%
Tarantula Oil Pipeline	4	30	100%
Total	813		

Hub Platforms

Enterprise has ownership interests in seven multi-purpose offshore hub platforms located in the Gulf of Mexico. These platforms are critical components of the offshore infrastructure in the Gulf of Mexico and play a key role in the overall development of offshore oil and natural gas reserves. Platforms are used to:

- **Process off-lease production,**
- **Interconnect with the offshore pipeline grid, and**
- **Host pipeline compression and pumping facilities.**

Our platforms generally earn revenues through demand and commodity charges. A demand charge is a fixed fee that is charged to a customer contracted to use our platform services regardless of the volume the customer delivers to the platform. A commodity charge is typically a fixed fee per Mcf of natural gas or barrel of crude oil multiplied by the volume delivered to the platform. Contracts for platform services often include both demand and commodity charges, but demand charges generally expire after a fixed period of time. For the three-month period that we owned the hub platforms, our net offshore platform processing volumes were 306 Bbtus/d of natural gas and 14 MBPD of crude oil.

Expected Growth From Southern Green Canyon

The Southern Green Canyon area in the central Gulf of Mexico is expected to be one of the largest basins in the deepwater Gulf. Between 2004 and 2007, six large platforms with a combined capacity to process 650 MBPD of crude oil and over 900 MMcf/d of natural gas will be commissioned by producers in this area. These capacities could increase significantly by 2008 if platforms for three more discoveries being considered for development are sanctioned. Our access to this prolific basin highlights our ability to leverage the return on the partnership's existing asset base through investments in new infrastructure projects. These developments utilize our offshore oil and natural gas pipelines, natural gas processing plants, NGL pipelines and fractionators and onshore natural gas pipelines. We earn a fee for each service we provide along our integrated system and serve producers by delivering their hydrocarbons to the highest value markets.

Independence Hub and Trail Development

The Independence Hub and Trail development is an example of our teaming with a group of exploration and production companies to facilitate the development of ultra-deepwater natural gas discoveries in the previously untapped Eastern Gulf of Mexico. Enterprise will design, construct, install and own the Independence Hub which is a semi-submersible platform designed to accommodate up to 850 MMcf/d of natural gas production. Enterprise will own an 80% interest in the Independence Hub with CalDive International owning the remaining 20% interest. Our $307 million capital investment in Independence Hub is supported by acreage dedications and demand charges for the first five years after completion.

Enterprise will also own 100% of Independence Trail, a 134-mile, 24-inch diameter natural gas pipeline with a capacity of 850 MMcf/d to transport production from the Independence Hub to an offshore interconnect with Tennessee Gas Pipeline. The partnership will invest $265 million to build this pipeline. First production into Independence Hub and Trail is expected in 2007.

Enterprise will design, construct and own Independence Hub, a 105-foot deep-draft, semi-submersible platform to be located on Mississippi Canyon Block 920. The platform, which will be operated by Anadarko, will handle production from six anchor natural gas fields and will have an excess payload capacity to support ten additional fields.

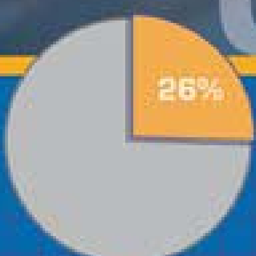
Offshore Platforms

	Water Depth (FEET)	Approximate Capacity Natural Gas (MMcf/d, NET)	Crude Oil (MBPD, NET)	our ownership interest
Marco Polo tension-leg platform	4,300	150	60	50%
Viosca Knoll 817	671	140	5	100%
Garden Banks 72	518	40	28	50%
Ship Shoal 332 A and B (1)	438	-	-	50%
East Cameron 373	441	190	5	100%
Falcon Nest	389	400	2	100%
Ship Shoal 331 (2)	376	-	-	100%

(1) The Ship Shoal 332 A and B platforms serve as junction platforms for the Manta Ray and Nemo natural gas pipelines and Poseidon, Allegheny and Cameron Highway crude oil pipelines.

(2) The Ship Shoal 331 platform is used by Maritech Resources, Inc. to support production operations.

ONSHORE

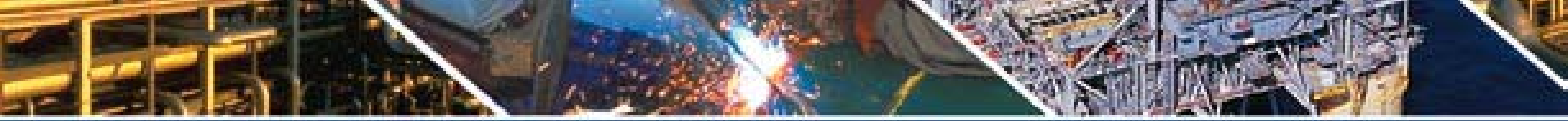


SEGMENT GROSS OPERATING MARGIN
FOURTH QUARTER 2004
The first quarter after the GulfTerra merger

Onshore Natural Gas Pipelines & Services

Enterprise's Onshore Natural Gas Pipelines and Services segment is comprised of the partnership's ownership interests in approximately 17,200 miles of natural gas pipeline systems in Texas, New Mexico, Louisiana, Mississippi, Alabama and Colorado. This segment also includes our investment in two high-deliverability natural gas storage facilities in Mississippi, which connect the Gulf Coast producing region to markets in the Northeast, Mid-Atlantic and Southeast, and leased natural gas storage facilities located in Texas and Louisiana.

Through these pipeline assets, we serve producers in some of the most significant long-lived basins in the nation such as the San Juan, Permian, Barnett Shale, South Texas, East Texas, South Louisiana and production from the Gulf of Mexico through connections with offshore pipelines. Our consuming customers include large industrial and electric generating customers in Texas and Louisiana and local natural gas distribution markets in Houston,



San Antonio, Austin, Baton Rouge and the New Orleans area. We also provide essential storage services with our strategically located facilities.

Natural Gas Pipelines

Generally, our natural gas pipelines generate revenue based on fees earned per unit of volume gathered or transported. Natural gas pipelines such as our Acadian Gas and Alabama Intrastate systems also gather and purchase natural gas from producers and suppliers and resell the natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers. In the fourth quarter of 2004, our onshore natural gas pipelines transported 5.6 TBtus/d, or approximately 9% of the daily demand for natural gas in the United States.

The partnership's San Juan Gathering System serves natural gas producers in the San Juan Basin of New Mexico and Colorado, where the system receives natural gas from approximately 9,500 connections. This 5,404-mile system gathers natural gas from wellhead connections and delivers it to our Chaco natural gas processing facility and to the San Juan natural gas processing facility, which is owned by third parties. In the fourth quarter of 2004, this system gathered approximately 1.3 TBtus/d of natural gas.

Last year we completed 251 new well connections to our San Juan system. One of our organic growth projects is to increase the capacity of this system by 10%, or 130 million cubic feet per day (MMcf/d). This $43 million optimization project began in late 2003 and will be completed in stages through 2006.

Enterprise's 8,222-mile Texas Intrastate System gathers and transports natural gas from supply basins in Texas and the Gulf of Mexico to local gas distribution companies, electric generation facilities and industrial customers. This system serves key natural gas markets in Texas, including the San Antonio/Austin area and the large industrial markets in the Houston Ship Channel, Beaumont/Orange and Corpus Christi areas. The Texas Intrastate System consists of the Texas Intrastate natural gas gathering system, the TPC Offshore natural gas gathering system and the Channel pipeline. During the fourth quarter of 2004, this system transported over 3.1 TBtus/d.

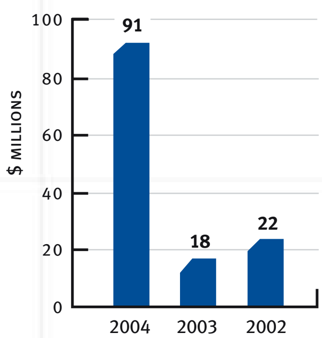
On the supply side, the Texas Intrastate System is benefiting from increased drilling activity and production from significant new discoveries in the central Texas Gulf

Onshore Natural Gas Pipelines

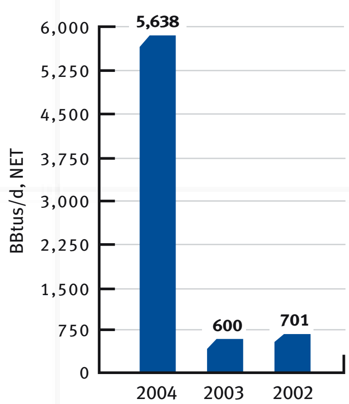
	Length In Miles	Approximate Capacity (MMcf/d, NET)	Our Ownership Interest
Texas Instrastate System [1]	8,222	4,975	100%[2]
San Juan Gathering System [1]	5,404	1,100	100%
Permian Basin System [1]	1,477	470	100%
Acadian Gas System	1,042	954	100%[3]
Alabama Intrastate System [1]	450	200	100%
Delmita Gathering System [1] [4]	295		100%
Big Thicket Gathering System [1] [4]	240		100%
Indian Springs Gathering System [5]	89		80%
Total	17,219		

(1) These pipelines were acquired as a result of the GulfTerra merger.
(2) The Texas Instrastate system includes some pipelines in which we own undivided interests.
(3) We own 100% of 1,015 miles of the Acadian Gas System and 49.5% of the related 27-mile Evangeline gas pipeline.
(4) These gathering systems are an integral part of our natural gas processing business, with the results of operations and assets included in our NGL Pipelines & Services business segment.
(5) We acquired an ownership interest in this natural gas gathering system in January 2005.

GROSS OPERATING MARGIN
Onshore Natural Gas Pipelines & Services



VOLUMES
Onshore Natural Gas Pipeline



Coast area, increased production in the Permian Basin and the continuing development of the Barnett Shale region. On the demand side, we continue to be the primary provider of transportation and storage services to both the City Public Service Board of San Antonio and Austin Energy, the electric service provider for the city of Austin, Texas. Our assets have been the primary service provider to these municipal owned utilities for more than 40 years. To serve demand growth in central Texas, we are developing a project to increase our pipeline capacity by 120 MMcf/d to deliver natural gas supplies from the Waha Hub in west Texas.

In the first quarter of 2005, we invested $74.5 million to expand our footprint in the producing areas of east Texas by acquiring interests in the Indian Springs natural gas gathering system and processing facilities. With interconnects to all of the major producing regions, end-user markets and pipeline hubs, our Texas onshore natural gas pipeline assets are positioned to continue to profit from favorable industry trends from both the supply and demand perspective.

Natural Gas Storage

Enterprise owns the Petal and Hattiesburg salt dome natural gas storage facilities, located near Hattiesburg, Mississippi that are connected to interstate pipelines serving the large Northeast, Mid-Atlantic and Southeast markets. These facilities have a combined certificated working storage capacity of 13.5 Bcf and are capable of delivering in excess of 1.2 Bcf/d of natural gas into five major interstate pipeline systems: Transco, Tennessee Gas Pipeline, Southern Natural Gas Pipeline, Destin Pipeline and Gulf South Pipeline. We also lease a natural gas storage facility in Texas having 6.4 Bcf of working capacity and a salt dome natural gas cavern in Louisiana with working gas storage capacity of 3.0 Bcf that serves our Acadian pipeline system.

The location of these facilities and their ability to accommodate large volumes of injections and withdrawals of natural gas make them well suited for customers who need the ability to meet swings in demand and to cover major disruptions of supply. Our Petal facility is 94% subscribed under fixed-fee agreements, with 7 Bcf dedicated under a 20-year contract to a subsidiary of Southern Company and 1.65 Bcf subscribed to a subsidiary of BP p.l.c. The partnership's Hattiesburg facility is currently fully subscribed and the Wilson facility in Texas is 96% subscribed. The stable nature of the cash flows and the strategic value of these assets make them an ideal component of our midstream value chain.

During 2004, we began an expansion project at our Petal natural gas storage facility. An existing cavern at our propane storage complex in Hattiesburg is being converted to natural gas service with 1.8 Bcf of working capacity. This cavern will be integrated with our Petal facility and is expected to be ready for service during the second quarter of 2005. We have executed long-term contracts to provide storage services to BP for the entire capacity of this new storage cavern.

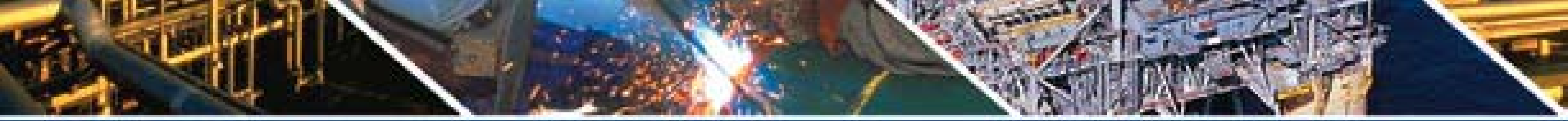
Natural Gas Storage Facilities

	Location	Gross Capacity (Bcf)	
Petal	Mississippi	9.5	100%
Hattiesburg	Mississippi	4.0	100%
Wilson (1)	Texas	6.4	Leased
Acadian (2)	Louisiana	3.0	Leased
Total		22.9	

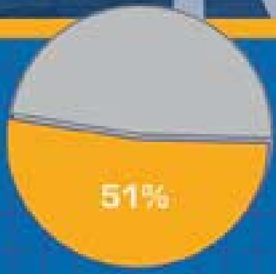
(1) We lease the Wilson natural gas storage facility under an operating lease that expires in January 2008.

(2) We lease the Acadian natural gas storage cavern under an operating lease that expires in December 2012. This storage facility is an integral part of our Acadian Gas System.

Acadian Gas Pipeline Interconnect *– Acadian increased its natural gas deliveries to the Baton Rouge market in 2004 with the completion of its interconnect near the LSU campus.*



NGL



Segment Gross Operating Margin
Fourth Quarter 2004
The first quarter after the GulfTerra merger

NGL Pipelines And Services

Enterprise's NGL Pipelines and Services segment is one of the largest integrated NGL systems in the United States. This system provides services to link most of the significant NGL producing areas in North America with the largest consumers of NGLs – the petrochemical and motor gasoline producing industries. At the core of this segment is our large NGL fractionation and storage complex in Mont Belvieu, Texas, which is the largest market hub for NGLs in the world. This segment includes the partnership's natural gas processing business and its related NGL marketing activities; NGL pipeline, storage and import/export terminaling services; and NGL fractionation business.

Natural Gas Processing and NGL Marketing

The first link in our NGL value chain is our 23 natural gas processing plants located in Texas, Louisiana, Mississippi and New Mexico. Eleven of these were acquired in connection with the GulfTerra merger. These facilities can be categorized as either straddle plants, located on mainline natural gas pipelines owned by Enterprise or by third parties, or field plants that process natural gas through associated gathering systems. The partnership's 11 facilities in Louisiana and Mississippi are situated on the major pipelines transporting natural gas from the continental shelf and deepwater areas of the Gulf of Mexico. Our 10 plants in Texas process natural gas produced from the south Texas, Permian and east Texas regions that is primarily transported through our Texas Intrastate pipeline system. Enterprise owns 2 plants in New Mexico including our large Chaco plant which is integrated with our 5,400-mile San Juan gathering system that gathers over 1 Bcf of natural gas per day.

In general, natural gas produced at the wellhead contains varying amounts of NGLs. This "rich" natural gas in its raw form is usually not acceptable for transportation in the nation's major natural gas pipeline systems or for commercial use as a fuel. Natural gas production from the deepwater Gulf of Mexico and the Rocky Mountains, thus far, has generally been rich in NGLs and typically must be processed to remove NGLs to meet pipeline quality specifications. Deepwater natural gas production can contain in excess of 4 gallons of NGLs per Mcf of natural gas as compared to 1 to 1.5 gallons of NGLs per Mcf of natural gas produced from the continental shelf areas of the Gulf of Mexico. Gas produced along the Texas Gulf coast typically contains 2-3 gallons of NGLs per Mcf. Natural gas processing plants remove the NGLs from the natural gas stream.

On an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemicals and motor gasoline than their value as components of the natural gas stream.

Enterprise restructured its natural gas processing contract portfolio in 2003 and 2004 resulting in the producer assuming all or most of the commodity price risk between NGLs and natural gas. At December 31, 2004, approximately 91% of the natural gas volumes were processed under contracts with a fee-based or in-kind fee component.

In January 2005, we purchased Teco Gas Processing, LLC from El Paso, which provided us with an indirect 75% interest in the Indian Springs natural gas processing facility. This east Texas facility has the capacity to process up to 120 MMcf/d of natural gas. In addition, there is an idle 20 MMcf/d processing train available to support increases in natural gas volumes. The natural gas processed at the Indian Springs processing facility is sourced from the Indian Springs Gathering System, which we acquired in the same transaction, as well as our nearby Big Thicket Gathering System. NGLs from this facility are transported to Mont Belvieu for fractionation.

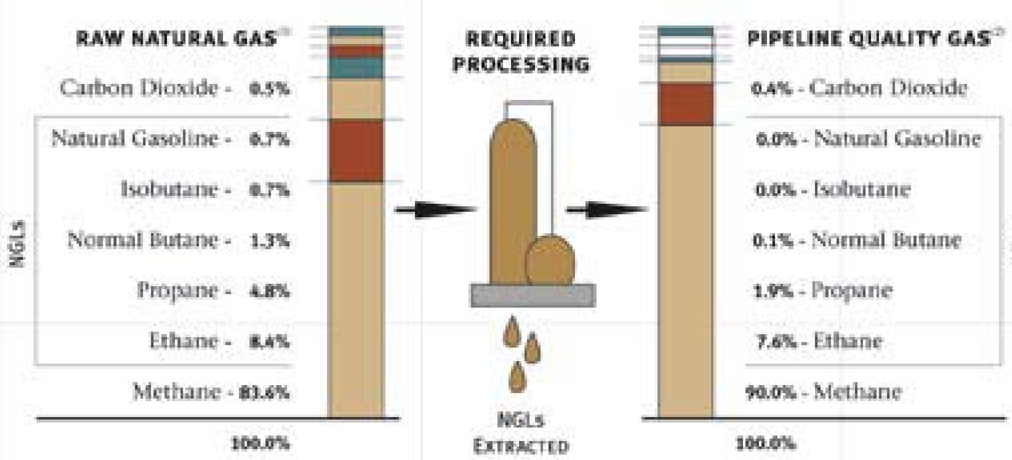
Over the next two years we are expecting new streams of rich natural gas production from the Southern Green Canyon, Thunder Horse and other developments in the deepwater Gulf of Mexico. These developments should produce a significant amount of NGLs that will be removed at our natural gas processing plants and most will also utilize our downstream pipeline, fractionation, storage and distribution facilities before reaching the end-use market.

NGL Pipelines and Storage

Enterprise owns interests in 12,774 miles of NGL pipelines and 157 million barrels of NGL and petrochemical storage capacity. These NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing plants to fractionation facilities; distribute and receive NGL products to and from petrochemical plants and refineries; and deliver propane to customers along the Dixie pipeline and certain sections of the Mid-America Pipeline System. Our pipelines provide transportation services to customers on a fee basis; therefore, the gross operating margin for this business is generally dependent upon the volume of product transported and the level of fees charged to customers. Typically, our pipeline customers retain title to the NGL products and the associated commodity price risk.

Enterprise's most significant NGL pipelines are the Mid-America and Seminole pipeline systems which total 8,507 miles. The Mid-America system is a regulated NGL pipeline system consisting of three NGL pipelines: the 2,548-mile Rocky Mountain pipeline, the 2,740-mile Conway North pipeline and the 1,938-mile Conway South pipeline.

NATURAL GAS PROCESSING DIAGRAM



[1] *Composition of unprocessed natural gas delivered to our Neptune plant*
[2] *Natural gas quality required by pipelines with 1,050 MMBtu per Mcf specifications*

The Rocky Mountain section of the pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. The Conway North segment links the large NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the Conway North segment has access to NGL supplies from Canada's Western Sedimentary basin through connections with third-party pipelines. The Conway South pipeline connects the Conway hub with Kansas refineries and transports NGLs from Conway to the Hobbs hub where the Mid-America system interconnects with the Seminole pipeline system.

The Seminole pipeline is a regulated pipeline that transports mixed NGLs and NGL products from the Hobbs hub and the Permian Basin area to Mont Belvieu. The primary source of throughput for Seminole is the volume originating from the Mid-America system. In general, mixed NGLs transported on the Seminole pipeline are transported to fractionation facilities in Mont Belvieu for separation and ultimate consumption by petrochemical customers and motor gasoline producers on the Texas Gulf Coast.

Because of strong drilling activity and increasing production of rich natural gas and associated NGLs in the Pinedale, Piceance and San Juan basins, our Mid-America system is operating near full capacity and NGLs that are dedicated to the partnership or our NGL fractionator at Mont Belvieu continue to exceed our capacity. As a result, we have begun two expansion projects to increase our capacity.

Enterprise's proposed Western Expansion Project would increase the capacity of the Rocky Mountain segment of the Mid-America pipeline system to 275 MBPD from its current capacity of 225 MBPD. A draft environmental assessment and plan of development has been submitted to the regulatory agencies and construction could begin as early as the fourth quarter of 2005 depending on the timing of required permits and regulatory approvals.

Earlier this year, the partnership began construction to expand its NGL fractionator at Mont Belvieu to facilitate the increase in NGLs from the Rocky Mountain area. This $34 million expansion project, which is expected to be completed in the first quarter of 2006, will increase our fractionation capacity by 15 MBPD from the fractionator's current capacity of 210 MBPD, and will also reduce

NGL Pipelines

	Length In Miles	Our Ownership Interest
Mid-America Pipeline System	7,226	98.0%
Dixie	1,301	65.9% (1)
Seminole	1,281	88.4% (2)
Texas NGL System (3)	1,039	100%
Louisiana Pipeline System	655	Various (4)
Promix (5)	410	50%
Lou-Tex NGL	206	100%
HSC	266	100%
Tri-States	169	66.7% (6)
Chunchula	143	100.0%
Belle Rose	48	41.7%
Wilprise	30	74.7%
Total	12,774	

(1) We acquired an additional 46.1% ownership interest in Dixie from ConocoPhillips (20%) and ChevronTexaco (26.1%) in January and February 2005, respectively.

(2) We acquired an additional 10% ownership interest in Seminole from ChevronTexaco in May 2004.

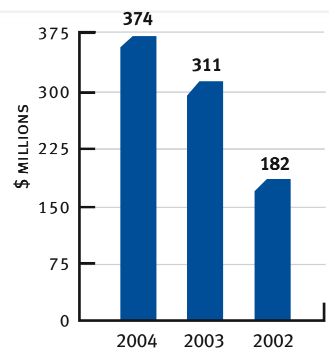
(3) Acquired as a result of the GulfTerra Merger on September 30, 2004.

(4) Of the 655 total miles for this system, we own 100% of 559 miles; 32.2% of 43 miles; and 44.3% of the remaining 53 miles.

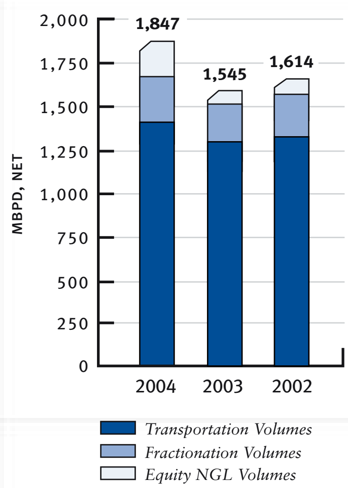
(5) The Promix gathering pipeline is an integral component of the NGL fractionation activities of Promix. We acquired an additional 16.7% ownership interest in Promix from Koch in December 2004.

(6) We acquired an additional 16.7% ownership interest in Tri-States from Koch in April 2004.

GROSS OPERATING MARGIN
NGL Pipelines & Services



VOLUMES
NGL Pipelines & Services



the facility's energy costs. With respect to the Western Expansion Project, we are also evaluating a project to build a new NGL fractionator at our Mont Belvieu complex that could increase the facility's fractionation capacity by an additional 60 MBPD to accommodate the expected increase in NGL production from the Rocky Mountain region.

In February 2005, we announced that we acquired an additional 46% interest in the Dixie Pipeline Company in 2 separate transactions totaling $71 million. Enterprise now owns 66% of the company. Dixie Pipeline Company owns and operates the Dixie Pipeline, a 1,300-mile propane pipeline that transports over 100 MBPD of propane from Mont Belvieu and 9 other receipt points to markets at its eastern termination points in North Carolina and Georgia, as well as 7 intermediate delivery terminals.

NGL Fractionation Services

NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, normal butane, isobutane and natural gasoline. The three primary sources of mixed NGLs fractionated in the United States are domestic natural gas processing plants, domestic crude oil refineries and imports of butane and propane mixtures.

Recoveries of mixed NGLs by natural gas processing plants represent the largest source of volumes processed by our NGL fractionators.

Enterprise owns interests in 9 NGL fractionators with a combined net fractionation capacity of 439 MBPD. These facilities are located on the Texas and Louisiana Gulf Coast and are linked by pipelines to some of the largest consumers of NGLs in the United States and to international markets through the partnership's import/export terminal on the Houston Ship Channel. Generally, the partnership receives a fee on the volume of NGLs fractionated.

Our Mont Belvieu NGL fractionator is one of the largest NGL fractionation facilities in the United States with a gross capacity of 210 MBPD. This facility fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian, San Juan, Rocky Mountain Overthrust, East Texas and the U.S. Gulf Coast. We own 75% of this facility.

The partnership's Norco NGL fractionator, located near New Orleans, Louisiana, has a gross capacity of 75 MBPD. This facility receives mixed NGLs via pipeline from refineries and natural gas processing plants. At this facility, Enterprise is compensated for fractionation services under percent-of-liquids, or in-kind fees, contracts and fee-based contracts. During 2004, long-term percent-of-liquids contracts exclusive to this facility accounted for approximately 51 MBPD, or approximately 90% of the total volume processed. Enterprise owns 100% of this facility.

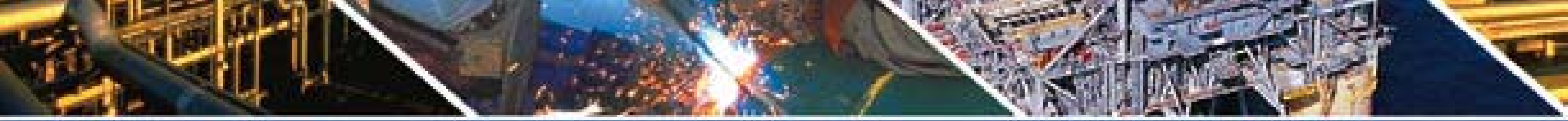
Promix owns a fractionator located in Napoleonville, Louisiana, which has the capacity to fractionate up to 145 MBPD of mixed NGLs from natural gas processing plants on the Louisiana, Mississippi and Alabama Gulf Coast. In December 2004, the partnership invested $27.5 million to acquire an additional 16.7% interest in the Promix fractionator. As a result, Enterprise and an affiliate of Dow Chemical Company each own a 50% interest in this facility. The Promix and Norco fractionators are the hubs of our NGL value chain in Louisiana, where we expect to see a substantial increase in NGL volumes flowing from the start up of new developments in the Gulf of Mexico including those in the prolific Southern Green Canyon area.

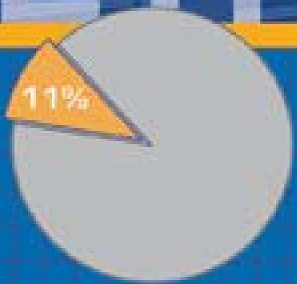
NGL Fractionation Facilities

		Gross Capacity (MBPD)	Our Ownership Interest	Net Capacity (MBPD)
Mont Belvieu	Texas	210	75.0%	158
South Texas (1)				
Shoup	Texas	69	100.0%	69
Armstrong	Texas	17	100.0%	17
Delmita	Texas	10	100.0%	10
Promix	Louisiana	145	50.0% (2)	73
Norco	Louisiana	75	100.0%	75
BRF	Louisiana	60	32.2%	19
VESCO	Louisiana	36	13.1%	5
Tebone	Louisiana	30	44.3%	13
Total Capacity		652		439

(1) Acquired as a result of the GulfTerra Merger. This list excludes the Almeda NGL fractionation facility (24 MBPD of capacity) that was acquired in connection with the GulfTerra Merger. At present, we have no plans to resume operations at the Almeda location.

(2) We acquired an additional 16.7% interest in Promix in December 2004.





SEGMENT GROSS OPERATING MARGIN
FOURTH QUARTER 2004
The first quarter after the GulfTerra merger

Petrochemical Services

The Petrochemical Services segment includes the partnership's propylene fractionation, butane isomerization and octane enhancement businesses and related pipeline assets. These facilities are located primarily at our Mont Belvieu, Texas, complex and along the Texas and Louisiana Gulf Coast.

Propylene Fractionation

Enterprise provides propylene fractionation, storage, transportation and export services to the petrochemical industry. Propylene is used in the production of plastic consumer products, pharmaceuticals, detergents and solvents. Demand for chemical and polymer grade propylene has grown by approximately 4% annually from 1996 to 2003 according to the industry trade association, Chemical Market Associates, Inc. ("CMAI"). In 2004, according to CMAI, worldwide demand for propylene grew by approximately 5% and is expected to continue to grow at that rate through 2008, with some years as high as 6%.

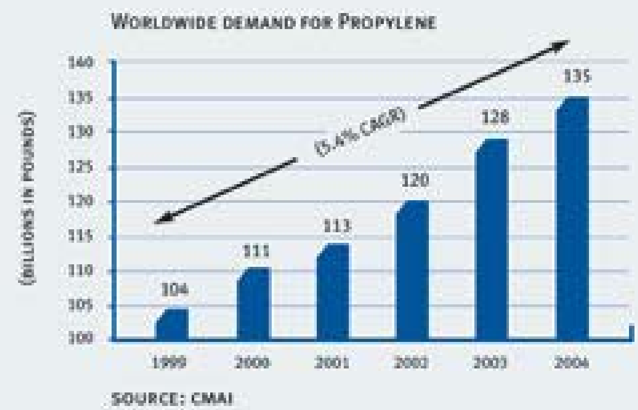
The two primary sources of polymer grade propylene are from ethylene steam crackers and from fractionators that separate propane/propylene mixes produced as a byproduct of crude oil refining. Projected growth in ethylene steam cracking capacity will not meet the expected demand for propylene. We believe propylene demand growth will be met primarily by fractionating refinery-sourced propane/propylene mixes.

Enterprise has been in the propylene fractionation business since 1978. We have ownership interests in four propylene fractionation plants that are connected to an extensive network of pipeline transportation, storage and import/export facilities, in Texas and

Louisiana, providing our customers with operational flexibility. Three of these plants are located in Mont Belvieu and have a combined net capacity to produce 58 MBPD of polymer grade propylene.

Polymer grade propylene is at least 99.5% pure propylene and is produced by fractionating chemical grade propylene or refinery grade propylene.

In addition to the three polymer grade propylene plants we own at Mont Belvieu, Enterprise also operates and owns a 30% interest in a chemical grade propylene fractionator as part of a joint venture with ExxonMobil Chemical near Baton Rouge, Louisiana. Enterprise designed, constructed and operates the plant and ExxonMobil supplies the feedstock to the facility and is the major customer for the end product. This fractionation facility has a gross capacity to produce 23 MBPD of chemical grade propylene.



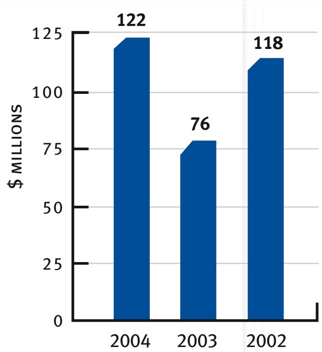
As demand for propylene increases driven by overall economic growth, we believe our partnership will benefit from higher utilization rates and fees from our existing facilities and opportunities to construct new facilities supported by long-term contracts with existing, as well as new customers.

Butane Isomerization

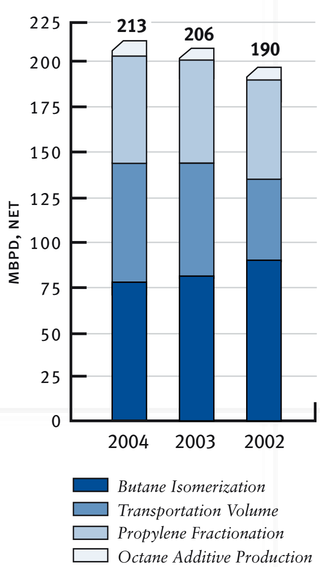
Butane isomerization is the process of converting normal butane into isobutane. Normal butane and isobutane are NGLs that are naturally produced from processing natural gas and as a byproduct from crude oil refining. The supply of normal butane generally exceeds demand, while the demand for isobutane is normally greater than the supply.

Isobutane is used primarily by the petrochemical industry for the production of propylene oxide. The annual domestic demand growth for propylene oxide during the past decade has been 1.5 times the growth rate of U.S. gross domestic product. Isobutane is also used to produce additives for motor gasoline that increase octane and lower vapor pressure. These additives are combined with motor gasoline to meet the federal environmental standards for exhaust emissions from automobiles.

GROSS OPERATING MARGIN
PETROCHEMICAL SERVICES



VOLUMES
PETROCHEMICAL SERVICES



Enterprise has been in the isomerization business since 1981 and owns 3 butane isomerization plants and 8 associated deisobutanizers with a combined net production capacity of 116 MBPD of isobutane. These facilities are located at Enterprise's Mont Belvieu complex and comprise the largest commercial isomerization complex in the world.

Petrochemical Pipelines

Enterprise's petrochemical pipelines are comprised of 460 miles of pipelines that transport polymer grade and chemical grade propylene and high purity isobutane from our facilities to customer facilities along the Texas and Louisiana Gulf Coast. The longest pipeline is the Lou-Tex Propylene pipeline that extends 291 miles from Sorrento, Louisiana, to Mont Belvieu. It transports chemical grade propylene for Shell and other third parties from production and storage facilities in Louisiana to Texas.

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2004 AND 2003

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership listed on the NYSE symbol "EPD". Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Enterprise" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. Certain abbreviated names and other capitalized and industry terms are defined within the glossary of this annual report.

We were formed in April 1998 to own and operate certain NGL related businesses of EPCO, Inc. ("EPCO," formerly Enterprise Products Company). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our "Operating Partnership"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as "Enterprise GP"). We and Enterprise GP are affiliates of EPCO.

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and notes beginning on page 65 of this annual report. In addition, the reader should review "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" on page 135 of this annual report for information regarding forward-looking statements made in this discussion. Other risks involved in our business are discussed under "*Quantitative and Qualitative Disclosures about Market Risk*" on page 54 of this annual report. Additionally, please see page 51 for a discussion of related party matters.

RECENT DEVELOPMENTS

GulfTerra Merger. On September 30, 2004, Enterprise and GulfTerra completed the merger of GulfTerra with a wholly owned subsidiary of Enterprise, with GulfTerra being the surviving entity thereof. Additionally, Enterprise completed certain other transactions related to the merger, including receipt of Enterprise GP's contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise GP from El Paso, and the purchase of certain midstream energy assets located in South Texas from El Paso. The aggregate value of the total consideration Enterprise paid or issued to complete the GulfTerra Merger was approximately $4 billion.

As a result of the GulfTerra Merger, GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise on September 30, 2004. On October 1, 2004, we contributed our ownership interests in GulfTerra and GulfTerra GP to our Operating Partnership, which resulted in GulfTerra and GulfTerra GP becoming wholly owned subsidiaries of the Operating Partnership.

Formed in 1993, GulfTerra manages a balanced, diversified portfolio of interests and assets relating to the midstream energy sector, which involves gathering, transporting, separating, processing, fractionating and storing natural gas, oil and NGLs. GulfTerra's interests and assets included (i) offshore oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure in the Gulf of Mexico, primarily offshore Louisiana and Texas; (ii) onshore natural gas pipelines and processing facilities in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas; (iii) onshore NGL pipelines and fractionation facilities in Texas; and (iv) onshore natural gas and NGL storage facilities in Louisiana, Mississippi and Texas.

The South Texas midstream assets consisted of nine natural gas processing plants with a combined capacity of 1.9 Bcf/d, a 294-mile natural gas gathering system, a natural gas treating facility with a capacity of 150 MMcf/d and a small NGL pipeline.

The GulfTerra Merger transactions

The GulfTerra Merger occurred in several interrelated transactions as described below.

- *Step One*. On December 15, 2003, Enterprise purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owns a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, Enterprise accounted for its investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One were borrowed under an Interim Term Loan and our pre-merger revolving credit facilities. This amount was fully repaid with the net proceeds from equity offerings completed during 2004. For additional information regarding changes in our debt obligations since December 31, 2003, please see Note 9 of the Notes to Consolidated Financial Statements beginning on page 96 of this annual report.

- *Step Two*. On September 30, 2004, the GulfTerra Merger was consummated and GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise. The GulfTerra Merger was accounted for using purchase accounting. Step Two of the GulfTerra Merger included the following transactions:

  - Immediately prior to closing the GulfTerra Merger, Enterprise GP acquired El Paso's remaining 50% membership interest in GulfTerra GP for $370 million in cash paid to El Paso and the issuance of a 9.9% membership interest in Enterprise GP to El Paso. Subsequently, Enterprise GP contributed this 50% membership interest in GulfTerra GP to us without the receipt of additional general partner interest, common units or other consideration. Enterprise GP borrowed the foregoing $370 million from Dan Duncan LLC (which owns a membership interest in Enterprise GP), which obtained the funds from a loan from EPCO (which indirectly owns the remaining membership interests in Enterprise GP).

  - Immediately prior to closing the GulfTerra Merger, Enterprise paid $500 million in cash to El Paso for 10,937,500 Series C units of GulfTerra and 2,876,620 common units of GulfTerra. The remaining 57,762,369 GulfTerra common units (7,433,425 of which were owned by El Paso) were converted into 104,549,823 Enterprise common units (13,454,499 of which are held by El Paso) at the time of the consummation of the GulfTerra Merger.

- *Step Three*. Immediately after Step Two was completed, Enterprise acquired certain South Texas midstream assets from El Paso for $155.3 million in cash. Pursuant to written agreements, our purchase of the South Texas midstream assets was effective September 1, 2004.

In connection with the closing of the GulfTerra Merger, on September 30, 2004, our Operating Partnership borrowed an aggregate $2.8 billion under its new revolving credit facilities to fund its cash payment obligations under Step Two and Step Three of the GulfTerra Merger and related transactions, including the tender offers for GulfTerra's outstanding senior and senior subordinated notes.

In connection with the GulfTerra Merger, we are required under a consent decree to sell our 50% interest in Starfish, which owns the Stingray natural gas pipeline and related gathering pipelines and dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana by March 31, 2005. In January 2005, we entered into a contract with a third party to sell this investment for approximately $42.1 million. We expect to close this sale during the first quarter of 2005. The sale requires FTC approval under the terms of the consent decree relating to the GulfTerra Merger and is subject to other customary closing conditions. Additionally, under the same consent decree, we were required to sell our undivided 50% interest in a Mississippi propane storage facility by December 31, 2004. We sold our interest in this facility during the fourth quarter of 2004.

For additional information regarding the GulfTerra Merger and our other business combinations and asset acquisitions completed during 2004 (including selected pro forma financial information), please read Note 4 of the Notes to Consolidated Financial Statements beginning on page 79 of this annual report.

Acquisition of El Paso's Interests in Enterprise and Enterprise GP by affiliates of EPCO. In January 2005, affiliates of EPCO acquired a 9.9% membership interest in Enterprise GP and 13,454,499 Enterprise common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and its affiliates own 100% of the membership interests of Enterprise GP and approximately 37.4% of our total outstanding common units. El Paso no longer owns any interest in us or Enterprise GP.

Agreement with Atwater Valley Producers Group for Deepwater Platform and Gas Pipeline. In November 2004, we entered into an agreement with the Atwater Valley Producers Group (consisting of Anadarko, Dominion, Kerr-McGee, Spinnaker and Devon) for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas of the deepwater Gulf of Mexico. We will design, construct, install and own Independence Hub, a 105-foot deep-draft, semi submersible platform with a two-level production deck, which will be capable of processing 850 MMcf/d of natural gas. The platform, which is estimated to cost approximately $385 million, will be operated by Anadarko. Cal Dive is our 20% joint venture partner in the Independence Hub Platform project. Additionally, we will construct, own, and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of approximately 850 MMcf/d of natural gas. The pipeline system, which is estimated to cost $280 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline.

Rocky Mountain NGL pipeline expansion and related NGL fractionation projects. In January 2005, we started a project to expand our Mont Belvieu NGL fractionator to accommodate increased production of NGLs being transported to Mont Belvieu from the Rocky Mountain area. Our Mont Belvieu facility's current fractionation capacity is up to 210 MBPD of mixed NGLs. This project, which is expected to be completed in the first quarter of 2006 at an estimated total cost of $34.2 million, will increase total fractionation capacity at this facility by 15 MBPD and reduce its energy costs. Additionally, we are reviewing a proposal to construct a new NGL fractionator at our Mont Belvieu complex that could add an additional 60 MBPD of fractionation capacity at this industry hub.

Currently, the Rocky Mountain segment of our Mid-America pipeline system transports up to 225 MBPD of NGLs from the major producing basins in Wyoming, Utah, Colorado and New Mexico to the Hobbs station on the Texas-New Mexico border. The Western Expansion Project would increase the capacity of this pipeline to 275 MBPD. Permitting, engineering and design work are in progress. We submitted a draft environmental assessment and plan of development to the appropriate regulatory agencies during the first quarter of 2005. Contingent upon receiving all required permits and regulatory approvals, construction could begin as early as the fourth quarter of 2005.

Acquisition of Indian Springs natural gas gathering and processing assets from El Paso. In January 2005, we paid El Paso $74.5 million for their membership interests in Teco Gas Gathering, LLC and Teco Gas Processing, LLC. As a result of this acquisition, we indirectly own an 80% equity interest in the 89-mile Indian Springs Gathering System and a 75% equity interest in the Indian Springs natural gas processing facility, both of which are located in East Texas. The Indian Springs processing facility has capacity to process up to 120 MMcf/d of natural gas and there is an idle 20 MMcf/d production train available for restart to support increases in natural gas volumes. The natural gas processed at the Indian Springs processing facility is sourced from the Indian Springs Gathering System, as well as our nearby Big Thicket Gathering System.

*February 2005 equity offering***.** In February 2005, we sold 17,250,000 common units (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005) to the public at an offering price of $27.05 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $9.1 million, were approximately $456.5 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $19.7 million. The net proceeds from this offering, including Enterprise GP's proportionate net capital contribution, were used to repay our 364-Day Acquisition Credit Facility, to temporarily reduce indebtedness outstanding under our Multi-Year Revolving Credit Facility or for general partnership purposes.

Acquisition of Additional Interests in Dixie Pipeline Company. We purchased an approximate 26% interest in Dixie from an affiliate of ChevronTexaco in February, 2005 for $40 million, and an approximate 20% interest in Dixie from an affiliate of ConocoPhillips in January, 2005 for $31 million. As a result of these acquisitions, our ownership interest in Dixie is now approximately 66% and will be a consolidated subsidiary. The other owners of Dixie are affiliates of BP with a 23% interest and ExxonMobil with an 11% interest. Dixie owns and operates the 1,301-mile Dixie Pipeline, which is a pipeline that transports propane from supply areas in Texas, Louisiana and Mississippi to markets throughout the southeastern United States. The Dixie Pipeline is regulated by the FERC and transports an average of approximately 100 MBPD per day of propane.

March 2005 private senior notes offering. On February 15, 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a private offering, comprised of $250 million in principal amount of 10-year senior unsecured notes and $250 million in principal amount of 30-year senior unsecured notes. The 10-year notes ("Senior Notes I") were issued at 99.379% of their principal amount and have fixed-rate interest of 5.00% and a maturity date of March 1, 2015. The 30-year notes ("Senior Notes J") were issued at 98.691% of their principal amount and have fixed-rate interest of 5.75% and a maturity date of March 1, 2035. The Operating Partnership used the net proceeds from the issuance of Senior Notes I and J to repay $350 million of indebtedness outstanding under Senior Notes A which was due on March 15, 2005 and the remaining proceeds for general partnership purposes, including the temporary repayment of indebtedness outstanding under the Multi-Year Revolving Credit Facility. This transaction closed on March 2, 2005. For additional information regarding our debt obligations, please read "*Our Liquidity and Capital Resources - Our Debt Obligations*" on page 36 and Note 9 of the Notes to Consolidated Financial on page 96 of this annual report.

*March 2005 $4 Billion Universal Shelf Registration Filing***.** On March 3, 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 36,572,122 common units currently owned by Shell and 4,427,878 common units that had been sold by Shell to Kayne Anderson MLP Investment Company in December 2004. We are obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999. For additional information regarding our equity and debt offerings, please read "*Our Liquidity and Capital Resources*" beginning on page 30 of this annual report.

OUR RESULTS OF OPERATIONS

As a result of completing the GulfTerra Merger on September 30, 2004, our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004 includes three months of results of operations from the GulfTerra assets. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004; thus, our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004 includes four months of results of operations from the South Texas midstream assets.

As a result of the GulfTerra Merger, we have reorganized our reportable business segments, as described below. We have also revised our prior segment information in order to conform to the current business segment operations and presentation.

We have segregated our business activities into four reportable business segments: Offshore Pipelines & Services, Onshore Natural Gas Pipelines & Services, NGL Pipelines & Services, and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered and products produced and/or sold. For a listing of the major components of each of our four new business segments, and the principal operating assets included within each of the major components, please read Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The Offshore Pipelines & Services business segment consists of (i) approximately 1,150 miles of offshore natural gas pipelines strategically located to serve production areas in some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 800 miles of Gulf of Mexico offshore crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico, which are included in our Offshore Pipelines & Services business segment.

The Onshore Natural Gas Pipelines & Services business segment consists of approximately 17,200 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. In addition, this segment includes two salt dome natural gas storage facilities located in Mississippi, which are strategically located to serve the Northeast, Mid-Atlantic and Southeast domestic natural gas markets. This segment also includes leased natural gas storage facilities located in Texas and Louisiana.

The NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 12,775 miles and related storage facilities, which include our strategic Mid-America and Seminole NGL pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminaling operations.

The Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes various petrochemical pipeline systems.

The Other non-segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP and our underlying investment in this entity at December 31, 2003. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with Step One of the GulfTerra Merger. Our investment in GulfTerra GP was accounted for using the equity method until the GulfTerra Merger was completed on September 30, 2004. On that date, GulfTerra GP became a wholly owned consolidated subsidiary of ours. Since the historical equity earnings of GulfTerra GP were based on net income amounts allocated to it by GulfTerra, it is impractical for us to allocate the equity income we received during the periods presented to each of our new business segments. Therefore, we have segregated equity earnings from GulfTerra GP from our other segment results to aid in comparability between the periods presented.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total (or consolidated) segment gross operating margin as operating income before: (1) depreciation, depletion and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions.

We have historically included equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be suppliers of raw materials or consumers of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs and petrochemicals. Our asset system has multiple entry points. In general, hydrocarbons can enter our asset system through a number of ways, including an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an NGL gathering pipeline, an NGL fractionator, an NGL storage facility, an NGL transportation or distribution pipeline or an onshore natural gas pipeline. At each link along this asset system, we earn revenues based on volume or an ownership of products such as NGLs.

Many of our equity investees are present within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines through our investments in Poseidon, Cameron Highway, Deepwater Gateway, Neptune and Nemo. We also have a number of investments in NGL transportation or distribution pipelines such as those owned by Belle Rose and Dixie (prior to our purchasing consolidating interests in Dixie in January and February 2005). Other examples include our use of the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold in our NGL marketing activities. Given the integral nature of our equity investees to our operations, we believe treatment of earnings from our equity method investees as a component of gross operating margin and operating income is appropriate.

For additional information regarding our investments in and advances to unconsolidated affiliates, please read Note 7 of the Notes to Consolidated Financial Statements included on page 87 of this annual report. For additional information regarding our business segments, please read Note 19 of the Notes to Consolidated Financial Statements beginning on page 126 of this annual report.

Our gross operating margin by segment and in total is as follows for the periods indicated:

	Year Ended December 31,		
	2004	**2003**	**2002**
Gross operating margin by segment:			
Onshore Natural Gas Pipelines & Services	$ 90,977	$ 18,345	$ 22,110
NGL Pipelines & Services	374,196	310,677	181,928
Petrochemical Services	121,515	75,885	117,776
Offshore Pipeline & Services	36,478	5,561	10,535
Other, non-segment	32,025	(53)	—
Total segment gross operating margin	$ 655,191	$ 410,415	$ 332,349

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for taxes, minority interest and the cumulative effect of changes in accounting principles, please read "*Other Items*" on page 52 of this annual report.

Selected Price and Volumetric Information

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil, selected NGL and petrochemical products and indicative gas processing gross spreads since the beginning of 2002:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound	Indicative Gas Processing Gross Spread, $/gallon
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(3)
2002										
1st Quarter	$2.34	$21.41	$0.22	$0.30	$0.38	$0.44	$0.47	$0.16	$0.12	$0.12
2nd Quarter	$3.38	$26.26	$0.26	$0.40	$0.48	$0.51	$0.58	$0.20	$0.17	$0.10
3rd Quarter	$3.16	$28.30	$0.26	$0.42	$0.52	$0.58	$0.61	$0.21	$0.16	$0.14
4th Quarter	$3.99	$28.33	$0.31	$0.49	$0.60	$0.63	$0.66	$0.20	$0.15	$0.13
Average for Year	$3.22	$26.08	$0.26	$0.40	$0.50	$0.54	$0.58	$0.20	$0.15	$0.12
2003										
1st Quarter	$6.58	$34.12	$0.43	$0.65	$0.76	$0.80	$0.85	$0.24	$0.21	$0.05
2nd Quarter	$5.40	$29.04	$0.39	$0.53	$0.58	$0.62	$0.65	$0.25	$0.19	$0.04
3rd Quarter	$4.97	$30.21	$0.37	$0.56	$0.67	$0.68	$0.73	$0.21	$0.15	$0.10
4th Quarter	$4.58	$31.18	$0.40	$0.58	$0.73	$0.71	$0.75	$0.22	$0.16	$0.17
Average for Year	$5.38	$31.14	$0.40	$0.58	$0.68	$0.70	$0.74	$0.23	$0.18	$0.09
2004										
1st Quarter	$5.69	$35.25	$0.43	$0.66	$0.76	$0.76	$0.87	$0.29	$0.26	$0.13
2nd Quarter	$6.00	$38.34	$0.45	$0.65	$0.79	$0.79	$0.92	$0.32	$0.26	$0.12
3rd Quarter	$5.75	$43.90	$0.52	$0.79	$0.92	$0.92	$1.05	$0.32	$0.27	$0.26
4th Quarter	$7.07	$48.31	$0.60	$0.85	$1.03	$1.04	$1.15	$0.40	$0.35	$0.22
Average for Year	$6.13	$41.45	$0.50	$0.74	$0.88	$0.88	$1.00	$0.33	$0.29	$0.18

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including OPIS and CMAI. Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents an average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.

(2) Crude oil price is representative of an index price for West Texas Intermediate.

(3) The Indicative Gas Processing Gross Spread is a relative measure used by the NGL industry as an indicator of the gross economic benefit derived from extracting NGLs from natural gas production on the U.S. Gulf Coast. Specifically, it is the amount by which the economic value of a composite gallon of NGLs exceeds the value of the equivalent amount of energy of natural gas based on NGL and natural gas prices on the U.S. Gulf Coast. It is assumed that a gallon of NGLs is comprised of 33% ethane, 32% propane, 11% normal butane, 8% isobutane and 16% natural gasoline. The value of a composite gallon of NGLs is determined by multiplying these component percentages by industry index prices listed in the table above. The value of the equivalent amount of energy of natural gas to one gallon of NGLs is 8.9% of the price of a MMBtu of natural gas. The Indicative Gas Processing Gross Spread does not consider the operating and fuel costs incurred by a natural gas processing plant to extract the NGLs nor the transportation and fractionation costs to deliver the NGLs and natural gas to market.

Our significant throughput, production and processing volumetric data were as follows for the periods indicated (on a net basis, taking into account our ownership interests):

	For Year Ended December 31,		
	2004 [1]	**2003** [1]	**2002** [1]
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d) [2]	2,081	433	500
Crude oil transportation volumes (MBPD)	138		
Platform gas treating (BBtus/d)	306		
Platform oil treating (MBPD)	14		
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	5,638	600	701
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,411	1,275	1,306
NGL fractionation volumes (MBPD)	307	227	235
Equity NGL production (MBPD)	129	43	73
Fee-based natural gas processing (MMcf/d)	1,692	194	
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	76	77	84
Propylene fractionation volumes (MBPD)	56	57	55
Octane additive production volumes (MBPD)	10	4	5
Petrochemical transportation volumes (MBPD)	71	68	46
Total, net:			
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,620	1,343	1,352
Natural gas transportation volumes (BBtus/d)	7,719	1,033	1,201
Equivalent transportation volumes (MBPD) [3]	3,651	1,615	1,668

(1) Volumetric data shown above reflects net operating rates of the underlying assets for the periods in which we owned them.
(2) Excludes fourth quarter of 2004 volumes for Starfish, which we are prohibited from obtaining under an FTC consent decree published for comment on September 30, 2004.
(3) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

The following table summarizes our consolidated revenues, costs and expenses, equity in income (loss) of unconsolidated affiliates and operating income for the periods indicated:

	For the Year Ended December 31,		
	2004	**2003**	**2002**
Revenues	$ 8,321,202	$ 5,346,431	$ 3,584,783
Operating costs and expenses	7,904,336	5,046,777	3,382,839
Selling, general and administrative costs	46,659	37,590	42,890
Equity in income (loss) of unconsolidated affiliates	52,787	(13,960)	35,253
Operating income	422,994	248,104	194,307
Interest expense	155,740	140,806	101,580
Net income	268,261	104,546	95,500

Comparison of Year Ended December 31, 2004 with Year Ended December 31, 2003

Revenues for 2004 increased $3.0 billion over those recorded during 2003. The increase in revenues is primarily due to (i) higher revenues from our NGL and petrochemical marketing activities due to increased sales volumes and prices and (ii) the addition of revenues from businesses acquired or consolidated during 2004, including GulfTerra, the South Texas midstream assets and BEF.

Costs and expenses increased $2.9 billion period-to-period primarily due to (i) an increase in volumes purchased including the effects of higher product prices which resulted in an increase in the cost of sales of our NGL and petrochemical marketing activities and (ii) the addition of costs and expenses attributable to assets acquired or consolidated during 2004. These increases in costs and expenses were partially offset by a gain on sale of assets of approximately $15.1 million related to the satisfaction of certain contractual requirements of a joint venture participation agreement whereby a 50% interest in Cameron Highway was sold. Approximately $10.1 million of this gain was the non-cash recognition of a long-term receivable that is due no later than December 31, 2006 while $5.0 million of the gain was associated with a contractually required cash payment received during the fourth quarter of 2004.

Our equity in earnings of unconsolidated affiliates increased $66.7 million period-to-period. The equity earnings we recorded for 2003 were impacted by a $22.5 million non-cash asset impairment charge associated with our octane enhancement business, BEF. The 2004 period includes $32 million of equity earnings from GulfTerra GP, which we began consolidating on September 30, 2004, as a result of completing the GulfTerra Merger. Additionally, 2004 includes the addition of equity earnings from investments acquired or consolidated during 2004, including VESCO and the investments we acquired in the GulfTerra Merger.

As a result of items noted in the previous paragraphs, operating income for 2004 increased $174.9 million from that recorded during 2003. Total segment gross operating margin increased $244.8 million year-to-year due to the same general reasons underlying the increase in operating income. Operating income includes costs such as depreciation and amortization and selling, general and administrative expenses that are excluded from the non-GAAP financial measure of total segment gross operating margin.

Net income increased $163.8 million to $268.3 million for 2004 compared to $104.5 million for 2003. Net income for 2004 included a $14.9 million increase in interest expense due to acquisition-related borrowings offset by a $10.8 million benefit associated with the cumulative effect of changes in accounting principles adopted during 2004. For additional information regarding the cumulative effect of changes in accounting principles we recorded during 2004, please read "*Other Items*" on page 52 of this annual report.

The following information highlights the significant year-to-year variances in gross operating margin by business segment; selling, general and administrative costs; and interest expense:

Onshore Natural Gas Pipelines & Services. Gross operating margin for our Onshore Natural Gas Pipelines & Services segment was $91 million for 2004 compared to $18.3 million for 2003. The majority of the $72.7 million increase in gross operating margin for this segment is attributable to assets acquired in the GulfTerra Merger, including various onshore natural gas pipelines and the Petal and Hattiesburg natural gas storage facilities. Additionally, gross operating margin for our Acadian gas pipeline system increased $6.8 million period-to-period due to higher natural gas transportation volumes and natural gas sales margins during 2004. The natural gas throughput volumes on our Acadian system were 595 BBtus/d for 2004 compared to 550 BBtus/d for 2003.

NGL Pipelines & Services. Gross operating margin from NGL Pipelines & Services segment was $374.2 million for 2004 compared to $310.7 million for 2003. Gross operating margin for natural gas processing increased $81.4 million period-to-period due to improved processing economics in 2004; the addition of gross operating margin attributable to assets acquired in the GulfTerra Merger, including the Chaco, Indian Basin and South Texas natural gas processing facilities; both partially offset by lower results from our NGL marketing activities in 2004. Indicative gas processing gross spreads on the U.S. Gulf Coast averaged 18 CPG during 2004 compared to 9 CPG in 2003, which resulted in an increase in the amount of NGLs extracted. Equity NGL production was 129 MBPD for 2004 versus 43 MBPD in 2003. Natural gas processing volumes under contracts with fee-based components increased to 1,692 MMcf/d for 2004 from 194 MMcf/d in 2003 reflecting amendments to our natural gas processing contract mix.

Gross operating margin from NGL pipelines and storage services decreased $24.7 million period-to-period due to (i) a $4 million non-cash asset impairment charge we recognized in 2004 on an NGL storage facility; (ii) increased expenses associated with our pipeline integrity inspection program; and (iii) lower gross operating margin from our Lou-Tex NGL pipeline resulting from a 17 MBPD decrease in volumes due to our election to maximize total gross operating margin by diverting mixed NGLs and refinery-grade propylene to our other facilities. Partially offsetting these decreases, was improved gross operating margin from our Mid-America and Seminole pipelines resulting from a 10% increase in throughput volumes. Overall, net NGL transportation volumes were 1,411 MBPD for 2004 compared to 1,275 MBPD in 2003.

Gross operating margin from NGL fractionation increased $6.8 million period-to-period. NGL fractionation volumes were 307 MBPD in 2004 compared to 227 MBPD in 2003. Gross operating margin from our Norco facility increased by $16.5 million primarily due to (i) a 16 MBPD increase in volumes resulting from an expansion completed in the fourth quarter of 2003 and (ii) the effect of higher prices on and an increase in NGL volumes sold by Norco that it earns ownership of through percent-of-liquids based fractionation contracts. Additionally, an increase in gross operating margin of $5.8 million is attributable to the South Texas fractionators which we acquired in the GulfTerra Merger. These increases were partially offset by a $14 million decrease in gross operating margin period-to-period from our Mont Belvieu NGL fractionator primarily attributable to the timing of gains and losses associated with the measurement of NGLs in storage pending fractionation and increased operating costs due to higher natural gas prices.

Petrochemical Services. Gross operating margin from our Petrochemical Services segment was $121.5 million in 2004 compared to $75.9 million in 2003. Gross operating margin from octane enhancement increased $34.4 million period-to-period primarily due to (i) a non-cash asset impairment charge of $22.5 million recorded in 2003 related to our investment in BEF and (ii) consolidating the results of BEF after our acquisition of the remaining 33.3% ownership interest during the third quarter of 2004. Gross operating margin from propylene fractionation increased $10.1 million period-to-period primarily due to higher petrochemical marketing sales volumes, which benefited from the effects of higher polymer grade propylene prices in 2004.

Offshore Pipelines & Services. Gross operating margin for our Offshore Pipelines & Services segment was $36.5 million for 2004 compared to $5.6 million for 2003. The $30.9 million increase in this segment is primarily attributable to assets acquired in the GulfTerra Merger, including various offshore oil and natural gas pipelines and offshore platforms. Partially offsetting this increase in gross operating margin is decreased equity earnings from our Neptune natural gas pipeline investment resulting from a decrease in volumes from the Brutus and Hickory fields and natural depletion of other production fields served by this system.

Selling, general and administrative costs. Selling, general and administrative costs were $46.7 million for 2004 compared to $37.6 million during 2003. The $9.1 million increase is primarily attributable to assets acquired or consolidated during 2004.

Interest expense. Interest expense increased to $155.7 million during 2004 from $140.8 million in 2003. The $14.9 million increase is primarily due to additional debt we incurred as a result of the GulfTerra Merger, partially offset by reduced loan cost amortization primarily related to our repayment during 2003 of the $1.2 billion senior unsecured 364-Day Term Loan which we used to fund the acquisition of our interests in the Mid-America and Seminole pipelines. Our weighted-average debt principal outstanding was $2.8 billion during 2004 compared to $2.0 billion during 2003. For additional information regarding our debt obligations and changes in our debt obligations since December 31, 2003, please read "*Our Liquidity and Capital Resources – Our Debt Obligations*," on page 36 of this annual report.

Comparison of Year ended December 31, 2003 with Year Ended December 31, 2002

Revenues for 2003 increased $1.8 billion over those recorded during 2002. Likewise, costs and expenses increased $1.7 billion over those of 2002. The increase in revenues and costs and expenses is primarily due to higher product sales and purchase prices and the financial results of business acquisitions, both of which offset the effect of lower volumes at some of our pipelines and facilities. In addition, costs and expenses for 2002 includes a $51.3 million loss related to commodity hedging activities.

In general, higher market prices result in increased revenues from our various marketing activities; however, these same higher prices also increase our cost of sales within these activities as feedstock and other purchase prices rise. In addition, higher natural gas market prices during 2003 increased energy-related costs for many of our businesses versus the same period in 2002. The weighted-average market price of NGLs was 57 CPG during 2003 versus 41 CPG during 2002. The market price of natural gas averaged $5.38 per MMBtu during 2003 versus $3.22 per MMBtu during 2002.

When compared to 2002, volumes at some of our downstream pipelines and facilities were lower due to a combination of (i) decreased demand for NGLs, principally ethane, by the ethylene segment of the petrochemical industry (the "ethylene industry") and (ii) lower NGL extraction rates at domestic gas processing facilities. The most significant determinant of the relative economic value of NGLs is demand by the ethylene industry for use in manufacturing plastics and chemicals. During 2003, this industry operated at lower utilization rates when compared to 2002 primarily due to a recession in the domestic manufacturing sector. Also during 2003, as a result of the higher relative cost of NGLs to crude-based alternatives such as naphtha, the ethylene industry utilized crude-based feedstock alternatives in greater quantities than during 2002. The resulting weaker demand for NGLs by this industry limited the ability of NGL producers to sell at higher product prices, which in turn resulted in decreased NGL extraction rates during 2003.

Equity earnings from unconsolidated affiliates decreased $49.2 million year-to-year primarily due to a $36.4 million decrease in equity earnings from BEF. The $36.4 million decrease in equity earnings from BEF is primarily due to a $22.5 million asset impairment charge we recorded during the third quarter of 2003; increased facility downtime during 2003 for maintenance and economic reasons; and an overall decrease in

MTBE sales margins. In addition to lower earnings from BEF, approximately $4.8 million of the overall decrease in equity earnings is due to a rate case settlement recorded by Starfish in 2002.

As a result of items noted in the previous paragraphs, operating income for 2003 increased $53.8 million from that posted during 2002. Total segment gross operating margin increased $78.1 million year-to-year due to the same general reasons underlying the increase in operating income. Operating income includes costs such as depreciation and amortization and selling, general and administrative expenses that are excluded from the non-GAAP financial measure of total segment gross operating margin.

Net income increased $9 million to $104.5 million for 2003 compared to $95.5 million for 2002. Net income for 2003 reflected the $53.8 million increase in operating income discussed in the previous paragraph offset by a $39.2 million increase in interest expense due to acquisition-related borrowings.

The following information highlights the significant year-to-year variances in gross operating margin by business segment; selling, general and administrative costs; and interest expense:

Onshore Natural Gas Pipelines & Services. Gross operating margin from our Onshore Natural Gas Pipelines & Services segment was $18.3 million for 2003 compared to $22.1 million for 2002. The decrease in gross operating margin was primarily due to lower natural gas sales volumes attributable to an increase in natural gas prices period-to-period. Overall, natural gas throughput volumes were 600 BBtus/d during 2003 versus 701 BBtus/d during 2002. The market price of natural gas averaged $5.38 per MMBtu during 2003 versus $3.22 per MMBtu during 2002.

NGL Pipelines & Services. Gross operating margin from our NGL Pipelines & Services segment was $310.7 million for 2003 versus $181.9 million for 2002. Gross operating margin from natural gas processing increased $49.3 million period-to-period. Our results for 2002 include $51.3 million in commodity hedging losses, the underlying strategies of which were discontinued in 2002. Our commodity hedging results for 2003 were a gain of $0.2 million.

Equity NGL production at our gas processing plants averaged 43 MBPD during 2003 compared to 73 MBPD during 2002. The decrease in equity NGL production year-to-year was largely attributable to reduced demand for NGLs, principally ethane, by the ethylene industry and higher natural gas prices relative to NGL prices, which caused most natural gas processors to minimize the amount of NGLs extracted at their facilities.

During 2003, we renegotiated a number of our natural gas processing contracts. In general, our objective has been to convert our traditional keepwhole arrangements to either margin-band/keepwhole contracts, percent-of-liquids contracts or fee-based contracts. The goal of these renegotiations is to minimize our direct exposure to the volatility of natural gas prices, especially to the extent it increases the PTR cost we would pay under traditional keepwhole arrangements to the point that processing natural gas to extract NGLs becomes uneconomical for us. When NGL extraction is uneconomical, NGLs are left in the natural gas stream to the extent allowed while keeping the natural gas in compliance with pipeline quality specifications; thus reducing the amount of NGLs available for downstream activities such as pipeline transportation and NGL fractionation.

Gross operating margin from NGL pipelines and storage increased $66.5 million period-to-period. The increase in gross operating margin was primarily due to our acquisition of Mid-America and Seminole. These two systems earned gross operating margin of $156.3 million during 2003 on aggregate net volumes of 774 MBPD. The 2002 period includes $81.1 million in gross operating margin for the five months during 2002 that we owned interests in these systems (August through December). When compared to their historical operating rates, net pipeline transportation volumes on the Mid-America and Seminole systems recorded for 2003 were lower than those reported by these systems for the full year of 2002 primarily due to decreased demand for NGLs, principally ethane, by the ethylene industry and lower NGL extraction rates at regional gas processing facilities. Excluding the contributions of Mid-America and Seminole, gross operating margin from NGL pipelines and storage was $77.3 million for 2003 versus $86 million for 2002. Net pipeline throughput volumes (excluding Mid-America and Seminole) increased to 501 MBPD during 2003 from 463 MBPD during the 2002 period.

Gross operating margin from NGL fractionation improved $12.9 million year-to-year. The increase in NGL fractionation gross operating margin is primarily due to (i) mixed NGL measurement gains we recognized during 2003 at our Mont Belvieu facility and (ii) higher percent-of-liquids revenues during 2003 at Norco attributable to the general increase in NGL prices, both of which more than offset a decline in gross operating margin from our other NGL fractionation facilities generally due to lower volumes and higher energy-related costs. Net NGL fractionation volumes decreased to 227 MBPD during 2003 from 235 MBPD during 2002. The decrease in NGL fractionation volumes period-to-period was primarily due to lower NGL extraction rates at gas processing facilities and reduced demand for NGLs by the petrochemical industry.

Petrochemical Services. Gross operating margin from our Petrochemical Services segment was $75.9 million for the 2003 period compared to $117.8 for the 2002 period. Gross operating margin from propylene fractionation declined $7.4 million year-to-year primarily due to lower petrochemical marketing margins resulting from higher feedstock and energy-related operating costs. Net propylene fractionation volumes were 57 MBPD for 2003 compared to 55 MBPD during 2002.

Gross operating margin from butane isomerization increased $6.8 million year-to-year. The increase in gross operating margin from isomerization was generally attributable to higher isomerization fees and by-product revenues, which were partially offset by lower volumes and higher energy-related operating costs. Isomerization volumes were 77 MBPD during the 2003 period compared to 84 MBPD during the 2002 period.

Our equity and consolidated earnings from octane enhancement were a loss of $32.7 million for 2003 compared to equity income of $8.6 million during 2002. The $41.3 million decrease in equity earnings is primarily due to a $22.5 million impairment charge we recorded during the third quarter of 2003 for our share of an impairment charge recorded by BEF; increased downtime during 2003 for maintenance and economic reasons; and an overall decrease in MTBE sales margins. Net MTBE production from this facility decreased to 4 MBPD during 2003 from 5 MBPD during 2002.

Offshore Pipelines & Services. Gross operating margin from our Offshore Pipelines & Services segment was $5.6 million for 2003 compared to $10.5 million for 2002. Overall, natural gas throughput volumes were 433 BBtus/d during 2003 versus 500 BBtus/d during 2002. The decrease in gross operating margin is primarily due to a $4.8 million reduction in equity earnings from Starfish related to the settlement of a rate case in 2002.

Selling, general and administrative costs. These expenses were $37.6 million for 2003 compared to $42.9 million during 2002. The 2002 period includes approximately $10.0 million that we paid to Williams for transition services associated with our acquisition of Mid-America and Seminole compared to $2.0 million paid in 2003 for these services. These payments ceased in February 2003 when we began operating these two pipeline systems.

Interest expense. Interest expense increased to $140.8 million during 2003 from $101.6 million in 2002. The increase is primarily due to additional debt we incurred as a result of business acquisitions. Interest expense for 2003 includes $11.3 million of loan cost amortization related to the 364-Day Term Loan, which was incurred in July 2002 and fully repaid in February 2003. Our weighted-average debt principal outstanding was $2.0 billion during 2003 compared to $1.8 billion during 2002.

General Outlook for 2005

We expect our business to be affected by the following key trends and events during 2005. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our expectations may vary materially from actual results.

- Drilling activity in the major producing areas, including the deepwater Gulf of Mexico, Rocky Mountains and San Juan, and the improving economy, have increased demand for our integrated midstream energy services. Over the next two years we expect large volumes of new production from both the deepwater and the Rockies to flow into our integrated system of assets.

  Our natural gas and NGL facilities in central Louisiana and our 50% owned Cameron Highway oil pipeline began receiving first production from the Mad Dog and Holstein developments in the Southern Green Canyon area of the deepwater Gulf of Mexico. These volumes, along with oil volumes received by our 36% owned Poseidon oil pipeline from the Front Runner development, should steadily increase during 2005 as these developments ramp up to full production. In addition, we expect initial production from the K-2 and K-2 North fields to begin flowing into our facilities in mid-2005.

- As a result of the continued strong demand for NGLs, most of our pipelines, fractionators and processing plants should continue to run at high utilization rates. The strength of the domestic and global economic recoveries should continue to drive increased demand for all forms of energy despite higher commodity prices. Our largest NGL consuming customers in the ethylene industry have seen strong demand for their products, which has enabled them to raise prices to mitigate higher fuel and feedstock costs. With the unusually high price of crude oil relative to natural gas, ethane and propane are the preferred feedstocks of the ethylene industry. With strong demand for their products, the ethylene industry has been operating at utilization rates in excess of 90%, which results in strong demand for all ethylene feedstocks.

- As a result of the GulfTerra Merger, we significantly increased our midstream assets located in the Gulf of Mexico. We have several projects that have either recently started operations or are scheduled to become operational soon. For additional information regarding these projects and our other capital spending, please read "*Our Liquidity and Capital Resources – Capital Spending*" on page 42 of this annual report.

- The effects of Hurricane Ivan have reduced volumes delivered to some of our pipelines, natural gas processing and NGL fractionation facilities in eastern Louisiana since the middle of September 2004. We estimate that this reduction in volumes resulted in a $24 million decrease in gross operating margin for the year ended December 31, 2004. This amount is prior to any potential recoveries under our business interruption insurance. In December 2004, volumes to these pipelines and facilities started to increase and we expect the volumes to return to normal levels by mid-2005.

OUR LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures, business acquisitions and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources (either separately or in combination) including cash flows from operating activities, borrowings under commercial bank credit facilities, the issuance of additional partnership equity and public or private placement debt. We expect to fund cash distributions to partners primarily with operating cash flows. For additional information regarding our quarterly cash distributions, please read page 134 of this annual report. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

As noted above, certain of our liquidity and capital resource requirements are fulfilled by borrowings made under debt agreements and/or proceeds from the issuance of additional partnership equity. At December 31, 2004, we had approximately $4.3 billion in principal outstanding under various debt agreements. For additional information regarding our debt, please read "– *Our Debt Obligations*" on page 36 of this annual report

As a result of our growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that additional financing arrangements to support our goals can be obtained on reasonable terms. Furthermore, we believe that maintenance of an investment grade credit rating combined with continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

Registration Statements

In February 2001, we filed a universal shelf registration with the SEC covering the issuance of up to $500 million of partnership equity or public debt obligations. In October 2002, we sold 9,800,000 common units under this shelf registration statement from which we received net proceeds of $182.5 million, including Enterprise GP's proportionate net capital contribution of $3.7 million. In January 2003, we sold an additional 14,662,500 common units under this shelf registration from which we received net proceeds of $258.1 million, including Enterprise GP's proportionate net capital contribution of $5.2 million. We used the net proceeds from these equity offerings to reduce debt outstanding under our 364-Day Term Loan and for working capital purposes. After deducting for these issuances of common units in October 2002 and January 2003, practically all of the available capacity under this shelf registration statement was used.

In January 2003, we filed a new $1.5 billion universal shelf registration statement with the SEC covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). Sine June 2003, we have sold 63,410,317 common units under this registration statement.

- In June 2003, we sold 11,960,000 common units under this shelf registration statement from which we received net proceeds of $261.1 million, including Enterprise GP's proportionate net capital contribution of $5.2 million. We used the net proceeds from this offering to reduce indebtedness outstanding under our revolving credit facilities.

- In May 2004, we sold 17,250,000 common units under this registration statement from which we received net proceeds of $353.1 million, including Enterprise GP's proportionate net capital contribution of $7.1 million. We used the proceeds from this public offering to repay the $225 million Interim Term Loan and to temporarily reduce borrowings outstanding under our revolving credit facilities.

- In August 2004, we sold 17,250,000 common units under this registration statement from which we received net proceeds of $341.2 million, including Enterprise GP's proportionate net capital contribution of $6.8 million. We used $210 million of the proceeds from this public offering to reduce borrowings outstanding under our revolving credit facilities and the remainder to fund our payment obligations to El Paso under Step Two of the GulfTerra Merger.

- In October and November 2004, we sold 1,950,317 common units under this registration statement from which we received net proceeds of $39.6 million, including Enterprise GP's proportionate net capital contributions. These common units were issued as a result of the conversion of GulfTerra's 80 outstanding Series F2 convertible units, which we assumed as a result of the merger, into Enterprise common units.

- In February 2005, we sold 17,250,000 common units under this registration statement (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005) from which we received net proceeds of approximately $456.5 million, including Enterprise GP's proportionate net capital contribution of $9.1 million. We used the proceeds from this public offering to repay our 364-Day Acquisition Credit Facility, to temporarily reduce indebtedness outstanding under our Multi-Year Revolving Credit Facility or for general partnership purposes.

After deducting for these issuances of common units in 2003, 2004 and 2005, practically all of the available capacity under this shelf registration statement has been used. On March 3, 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 36,572,122 common units currently owned by Shell and 4,427,878 common units owned by third party, Kayne Anderson. Shell sold these unregistered units to Kayne Anderson in December 2004. We are obligated to register the resale of these common units for Shell under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999.

In July 2003, we filed a registration statement with the SEC covering 5,000,000 common units issuable under the Distribution Reinvestment Plan (or "DRIP"). In April 2004, we filed a new registration statement with the SEC covering an additional 10,000,000 common units issuable under the DRIP. The new registration statement increased the number of common units issuable under the DRIP from 5,000,000 to 15,000,000. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional common units. We expect to use the cash generated from this reinvestment program primarily for general partnership purposes. Initial reinvestments under the DRIP occurred in August 2003. For all of 2003, we issued 2,883,803 common units in connection with the DRIP and received proceeds (including Enterprise GP's proportionate net capital contributions) of approximately $60.3 million. During 2004, we issued 5,183,591 common units in connection with the DRIP and received proceeds (including Enterprise GP's proportionate net capital contributions) of approximately $111.6 million. To support our growth objectives and financial flexibility, EPCO reinvested approximately $177.5 million of its cash distributions from August 2003 through February 2005 through the DRIP.

Class B special units

In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO for $100 million in a private transaction. Enterprise GP contributed approximately $2 million in connection with this offering in order to maintain its ownership interest. We used the net proceeds from this offering to repay $100 million of the debt we incurred to finance our December 2003 purchase of a 50% interest in GulfTerra GP and the remainder for general partnership purposes. Upon receipt of unitholder approval on July 29, 2004, our 4,413,549 Class B special units converted to an equal number of common units. This conversion resulted in a reclassification of the $99 million capital account balance for the Class B special units to common units.

Series F2 convertible units assumed in connection with the GulfTerra Merger

In May 2003, GulfTerra issued 80 Series F convertible units in a registered offering to an institutional investor. Each Series F convertible unit was comprised of two separate detachable units – a Series F1 convertible unit and a Series F2 convertible unit – that had identical terms except for vesting and termination dates and the number of common units into which they may be converted. Prior to the GulfTerra Merger, all the Series F1 convertible units were converted. As a result of the GulfTerra Merger, we assumed GulfTerra's obligations associated with the 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive Enterprise common units. The number of Enterprise common units and the price per unit at conversion were adjusted based on the 1.81 exchange ratio. The Series F2 convertible units were convertible into up to $40 million of Enterprise common units.

On October 29, 2004, 60 of the 80 outstanding Series F2 convertible units were converted into 1,458,434 Enterprise common units. As a result of this conversion, we received a payment of $30 million from the holder of the Series F2 convertible units (representing a conversion price of $20.57 per Enterprise common unit). Net proceeds from this conversion, including Enterprise GP's proportionate capital contribution of $0.6 million, were $29.7 million after deducting transaction costs of $0.9 million.

On November 8, 2004, the remaining 20 outstanding Series F2 convertible units were converted into 491,883 Enterprise common units. As a result of this conversion, we received a payment of $10 million from the holder of the Series F2 convertible units (representing a conversion price of $20.33 per Enterprise common unit). Net proceeds from this conversion, including Enterprise GP's proportionate capital contribution of $0.2 million, were $9.9 million after deducting transaction costs of $0.3 million.

CASH FLOWS FROM OPERATING, INVESTING AND FINANCING ACTIVITIES

The following discussions highlight significant year-to-year comparisons in consolidated operating, investing and financing cash flows:

	For Year Ended December 31,		
	2004	**2003**	**2002**
Net income	$ 268,261	$ 104,546	$ 95,500
Adjustments to reconcile net income to cash flows provided by (operating activities before changes in operating accounts:			
Depreciation and amortization in operating costs and expenses	193,734	115,642	86,029
Depreciation and amortization in selling, general and administrative costs	1,650	159	77
Amortization in interest expense	3,503	12,634	8,819
Equity in (income) loss of unconsolidated affiliates	(52,787)	13,960	(35,253)
Distributions received from unconsolidated affiliates	68,027	31,882	57,662
Provision for impairment of long-lived asset	4,114	1,200	
Gain on sale of assets	(15,901)	(16)	(1)
Cumulative effect of changes in accounting principles	(10,781)		
Changes in fair market value of financial instruments	5	(29)	10,213
Increase in restricted cash	(12,305)	(5,100)	(2,999)
Other	25,441	23,839	14,060
Cash flow from operating activities before changes in operating accounts	472,961	298,717	234,107
Net effect of changes in operating accounts	(93,725)	120,888	92,655
Operating activities cash flows	$ 379,236	$ 419,605	$ 326,762

Cash flows from operating activities primarily reflect net income adjusted for depreciation, amortization and similar non-cash amounts; equity earnings and cash distributions from unconsolidated affiliates and changes in operating accounts. The net effect of changes in operating accounts is generally the result of timing of cash receipts from sales and cash payments for purchases and other expenses near the end of each period. For additional information regarding changes in operating accounts, please read Note 17 of the Notes to Consolidated Financial statements on page 121 of this annual report.

In addition, operating cash inflows and outflows related to increases or decreases in inventory are influenced by changes in commodity prices and our marketing activities. Cash flow from operations is primarily based on earnings from our business activities. As a result, these cash flows are exposed to certain risks.

We operate predominantly in the midstream energy sector, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. In general, we provide services for producers and consumers of natural gas, NGLs and crude oil from the wellhead to the end user. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating, feedstocks in petrochemical manufacturing, and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products or increased competition from other service providers or producers due to pricing differences or other reasons could have a negative impact on our earnings and thus the availability of cash from operating activities. Other risks include fluctuations in oil, natural gas and NGL prices, competitive practices in the midstream energy industry and the impact of operational and systems risks. For a more complete discussion of these and other risk factors pertinent to our business, please read "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" on page 135 of this annual report.

Comparison of Year Ended December 31, 2004 with Year Ended December 31, 2003

Operating activities. Cash provided by operating activities was $379.2 million during 2004 compared to $419.6 million for 2003. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $473 million for 2004 versus $298.7 million for 2003. We believe that cash flow from operating activities before the net effect of changes in operating accounts is an important measure of our ability to generate core cash flows from our assets and other investments. The $174.3 million increase in this element of our cash flows is primarily due to:

- earnings from the assets we acquired in the GulfTerra Merger and in our purchase of the South Texas midstream assets, which occurred on September 30, 2004;
- the 2004 period including a gain on sale of assets of approximately $15.1 million related to the satisfaction of certain contractual requirements of a joint venture participation agreement whereby a 50% interest in Cameron Highway was sold; offset by
- higher interest costs associated with debt incurred and issued to fund our cash payment obligations associated with the GulfTerra Merger.

Distributions received from our equity method unconsolidated affiliates were $68 million for 2004 compared to $31.9 million for 2003 and equity income received from our equity method unconsolidated affiliates was $52.8 million for 2004 compared to a loss of $14.0 million for 2003. The increases in these components of our cash flows is primarily due to cash distributions and equity income received from GulfTerra GP and VESCO, offset by the effects of consolidating former equity method investments as a result of acquisitions. As a result of the GulfTerra Merger, GulfTerra GP became a wholly owned subsidiary of the Operating Partnership (see Note 4 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report). Additionally, on July 1, 2004, we changed our method of accounting for VESCO from the cost method to the equity method in accordance with EITF 03-16 (see Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report). The period-to-period fluctuation in the restricted cash balance is primarily due to the timing of physical purchases of natural gas on the NYMEX exchange.

Investing activities. During 2004, we used $929.1 million in cash for investing activities compared to $657 million in 2003. We used $638.8 million during 2004 to complete the GulfTerra Merger, including our purchase of the South Texas midstream assets. Additionally, during 2004, we used $85.9 million to purchase certain assets located near Morgan's Point, Texas, an additional 16.7% membership interest in Tri-States, a 10% equity interest in Seminole and the remaining 33.3% ownership interest in BEF. During 2003, we used $37.3 million primarily to purchase the Port Neches Pipeline, the remaining 50% ownership interest in EPIK, an additional 33.3% interest in BEF, an additional 37.4% interest in Wilprise and the remaining 50% interest in OTC. Capital expenditures were $146.9 million for 2004 versus $145.9 million for 2003. For additional information regarding our capital expenditures, please read "*Capital Spending*" included within this Item 7. Investments in and advances to unconsolidated affiliates were $64.4 million for 2004 compared to $471.9 million for 2003. During 2004, we used $27.5 million to purchase an additional 16.7% interest in Promix and we contributed $24 million to Cameron Highway for the construction of the Cameron Highway oil pipeline. The 2003 period included our payment of $425 million to El Paso for a 50% ownership interest in GulfTerra GP and amounts we contributed to our Gulf of Mexico natural gas pipeline investments for their expansion capital projects.

Financing activities. Cash provided by financing activities during 2004 was $544 million compared to $254 million in 2003. During 2004, we had net borrowings under our debt agreements of $125.6 million compared to net repayments of $106.8 million for 2003. On September 30, 2004, we borrowed approximately $2.8 million under our new 364-Day Acquisition Credit Facility and Multi-Year Revolving Credit Facility to (a) fund $655.3 million in cash payment obligations to El Paso under Steps Two and Three of the GulfTerra Merger transactions, (b) escrow $1.1 billion to finance our tender offers for GulfTerra's senior and senior subordinated notes and (c) extinguish $962 million outstanding under GulfTerra's revolving credit facility and secured term loans. Additionally, on October 4, 2004, we issued $2 billion in senior notes (Senior Notes E, F, G and H). Our repayments of debt during 2004 reflect the use of proceeds from our May 2004 and August 2004 equity offerings to repay the $225 million Interim Term Loan and to temporarily reduce amounts outstanding under our pre-merger revolving credit facilities and the use of proceeds from our October 2004 issuance of senior notes to reduce debt amounts outstanding under our 364-Day Acquisition Credit Facility. Additionally, on October 5, 2005, we used the $1.1 billion in escrowed funds to complete our cash tender offers for substantially all of GulfTerra's senior and senior subordinated notes. The 2003 period reflects our issuance of Senior Notes C ($350 million in principal amount) and Senior Notes D ($500 million in principal amount), and a $425 million borrowing under our Interim Term Loan which was used to purchase a 50% interest in GulfTerra GP. Repayments of debt during 2003 reflect the use of proceeds from equity offerings completed in January, June, August and December and the final repayment of $1 billion that was outstanding under the bridge loan financing we used to purchase interest in the Mid-America and Seminole pipelines.

Cash distributions to partners increased from $309.9 million during 2003 to $438.8 million during 2004. The increase in cash distributions is primarily due to an increase in both the declared quarterly distribution rates and the number of units eligible for distributions. We expect that future cash distributions to partners will increase as a result of our periodic issuance of common units under the DRIP and other equity offerings.

Net proceeds from the issuance of common units were $846.1 million for 2004 compared to $573.7 million for 2003. Both amounts include Enterprise GP's net proportionate capital contributions. In May 2004, we sold 17,250,000 common units to the public (including the underwriters' over-allotment amount of 2,250,000 common units) at an offering price of $21.00 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $7.1 million, were $353.1 million after deducting applicable underwriting discounts, commissions and offering expenses of $16.3 million. In August 2004, we sold 17,250,000 common units to the public (including the underwriters' over-allotment amount of 2,250,000 common units) at an offering price of $20.20 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $6.8 million, were approximately $341.2 million after deducting applicable underwriting discounts, commissions and offering expenses of $13.9 million. The 2004 period also includes $111.6 million in proceeds from the sale of 5,183,591 common units in connection with the DRIP, the proceeds of which were primarily used for general partnership purposes, and $39.6 million in proceeds from the conversion of 80 Series F2 convertible units into 1,950,317 common units. Proceeds from the issuance of common units during 2003 reflect the sale of 14,662,500 and 11,960,000 common units in our January 2003 and June 2003 equity offerings, respectively, and the sale of 2,883,803 common units in connection with the DRIP. Additionally, the 2003 period reflects the sale of 4,413,549 Class B special units to an affiliate of EPCO in December 2003.

Comparison of Year Ended December 31, 2003 with Year Ended December 31, 2002

Operating cash flows. Cash provided by operating activities was $419.6 million during 2003 compared to $326.8 million during 2002. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $298.7 million during 2003 versus $234.1 million during 2002. The $64.6 million increase in this element of our cash flows is primarily due to:

- earnings from newly acquired businesses which are included in the 2003 period but not in the 2002 period (particularly those of Mid-America and Seminole, which we acquired in July 2002);
- the 2002 period including $51.3 million of commodity hedging losses versus $0.6 million of such losses during the 2003 period; offset by
- higher interest costs associated with debt we incurred and issued since the first quarter of 2002 to finance acquisitions.

Distributions and equity income received from our equity method unconsolidated affiliates during 2003 decreased $25.8 million and $49.2 million, respectively, over those received in 2002. The decreases in these components of our cash flows are primarily due to consolidating former equity method investments as a result of acquisition. Additionally, the 2003 period reflects a decrease in equity earnings from BEF primarily due to a $22.5 million asset impairment charge we recorded during the third quarter of 2003.

Investing cash flows. During 2003, we used $657.0 million in cash for investing activities compared to $1.7 billion during 2002. We used $37.3 million and $1.6 billion for business acquisitions during 2003 and 2002, respectively. The 2002 period reflects our acquisition of interests in the Mid-America and Seminole pipelines from Williams and propylene fractionation and NGL and petrochemical storage assets from Diamond-Koch. The 2003 period includes only minor acquisitions, specifically the Port Neches pipeline and additional interests in EPIK, BEF, Wilprise and OTC.

Investments in and advances to unconsolidated affiliates increased to $471.9 million during 2003 compared to $13.7 million during 2002. The 2003 period includes our payment of $425 million to El Paso for a 50% ownership interest in the general partner of GulfTerra in December 2003. The remaining $33.2 million year-to-year increase is primarily due to funding our share of the expansion projects of our Gulf of Mexico natural gas pipeline investments and our purchase of an additional interest in Tri-States.

Our capital expenditures were $145.9 million during 2003 versus $72.1 million during 2002. The $73.8 million increase in capital expenditures is primarily due to expansions of our Norco NGL fractionator and Neptune gas processing facility.

Financing cash flows. Cash provided by financing activities during 2003 was $254 million compared to $1.3 billion during 2002. During 2003, we made net payments on our debt obligations of $106.8 million. Our borrowings during 2003 include the issuance of Senior Notes C ($350 million in principal amount), Senior Notes D ($500 million in principal amount) and the $425 million borrowing under the Interim Term Loan (to purchase a 50% interest in the general partner of GulfTerra). Our repayments during 2003 include the use of proceeds from equity offerings completed in January, June, August and December. The 2002 period primarily reflects borrowings to fund the Mid-America and Seminole acquisitions and those of Diamond-Koch's propylene fractionation business.

Proceeds from our common unit and Class B special unit equity offerings during 2003 totaled $675.7 million, which includes Enterprise GP's related $7.8 million contribution to us. Enterprise GP also contributed $5.9 million to our Operating Partnership in connection with these offerings. Distributions to our partners and minority interests increased to $318.0 million during 2003 from $218.2 million during 2002. The $99.8 million increase in distributions to partners is primarily due to increases in both the declared quarterly distribution rates and the number of units eligible for distributions.

OUR DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:	December 31, 2004	December 31, 2003
Operating Partnership debt obligations:		
Interim Term Loan, variable rate, repaid in May 2004 (1)		$ 225,000
364-Day Revolving Credit Facility, variable rate, terminated in September 2004 (2)		70,000
Multi-Year Revolving Credit Facility, variable rate, terminated in September 2004 (2)		115,000
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (3, 4)	$ 242,229	
Multi-Year Revolving Credit Facility, variable rate, due September 2009 (2,4)	321,000	
Seminole Notes, 6.67% fixed-rate, $15 million due in December 2005 (5)	15,000	30,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes A, 8.25% fixed-rate, repaid March 2005	350,000	350,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000	
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	
GulfTerra debt obligations: (5)		
Senior Notes, 6.25% fixed-rate, due June 2010 (6)	750	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2010	3,858	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2011	1,777	
Senior Subordinated Notes, 10.625% fixed-rate, due December 2012	84	
Total principal amount	4,288,698	2,144,000
Net unamortized discounts	(9,239)	(5,983)
Other	1,777	1,531
Subtotal long-term debt	4,281,236	2,139,548
Less current maturities of debt (7)	(15,000)	(240,000)
Long-term debt	$ 4,266,236	$ 1,899,548
Standby letters of credit outstanding (8)	$ 139,052	$ 1,300

(1) We used the proceeds from our May 2004 common unit offering to fully repay and terminate the Interim Term Loan.

(2) These facilities were terminated on September 30, 2004, and replaced by a new Multi-Year Revolving Credit Facility having $750 million of borrowing capacity due September 2009.

(3) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility.

(4) These facilities became effective concurrently with the closing of the GulfTerra Merger on September 30, 2004. The new $750 million Multi-Year Revolving Credit Facility replaced the $230 million 364-Day Revolving Credit Facility and the $270 million then existing Multi-Year Revolving Credit Facility. The $750 million borrowing capacity is reduced by the amount of standby letters of credit outstanding.

(5) Solely as it relates to the assets of our GulfTerra and Seminole subsidiaries, our senior indebtedness is structurally subordinated and ranks junior in right of payment to indebtedness of GulfTerra and Seminole.

(6) Remaining notes outstanding were called and retired in February 2005.

(7) In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*," long-term and current maturities of debt at December 31, 2004 reflected (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment of our 364-Day Acquisition Credit Facility using proceeds from an equity offering completed in February 2005. Our classification of current maturities of debt at December 31, 2003 reflected our option and ability to convert any revolving credit balance outstanding at maturity under the 364-Day Revolving Credit Facility to a one-year term loan (which would have been due October 2005) in accordance with the terms of the agreement.

(8) Of the $139 million standby letters of credit outstanding at December 31, 2004, $24 million were issued under our Multi-Year Revolving Credit Facility, and the remaining $115 million is associated with a letter of credit facility we entered into in November 2004 in connection with our Independence Hub capital project.

General Description of Consolidated Debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2004:

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes and the senior and senior subordinated notes of GulfTerra. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 88.4% of its capital stock). The senior and senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

GulfTerra's Senior Subordinated and Senior Notes. As a result of completing the GulfTerra Merger on September 30, 2004, we recorded in consolidation GulfTerra's $921.5 million of outstanding senior and senior subordinated notes. Of this amount, $915 million was purchased on October 5, 2004 by our Operating Partnership pursuant to its tender offers. The note holders also approved amendments in connection with accepting the tender offers that removed all restrictive covenants governing the notes. For additional information regarding the tender offers, please read " – *364-Day Acquisition Credit Facility – Tender offers for GulfTerra senior and senior subordinated notes*" within this general description of debt. In February 2005, we redeemed, at a premium, the remaining $0.8 million outstanding under GulfTerra's 6.25% senior notes due June 2010.

364-Day Acquisition Credit Facility. In August 2004, our Operating Partnership entered into a new 364-day credit agreement. The $2.25 billion Acquisition Credit Facility was an unsecured 364-day facility that was used to provide interim financing for certain transactions associated with the GulfTerra Merger, the refinancing of GulfTerra's existing secured credit facility and term loans and the purchase of GulfTerra's senior and senior subordinated notes in connection with our Operating Partnership's tender offers for those notes. This facility became effective concurrent with the closing of the GulfTerra Merger and was to mature on September 29, 2005. In February 2005, we fully repaid and terminated the 364-Day Acquisition Credit Facility using proceeds we received from our February 2005 common unit offering. For additional information regarding the February 2005 common unit offering, please read "*Recent Developments*" on page 19 of this annual report.

As defined by the credit agreement, variable interest rates charged under this facility generally bore interest, at our election at the time of each borrowing, at (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate.

This credit agreement provided for the mandatory prepayment of loans and termination of commitments equal to the proceeds from and upon the consummation of any public or private debt or equity offerings by us on or after August 15, 2004, excluding equity issued with respect to our distribution reinvestment plan, employee unit purchase plan and the exercise of any outstanding options with respect to our common units. With the completion of our private offering of senior notes on October 4, 2004, we repaid approximately $2 billion borrowed under this facility, which reduced our borrowing capacity under this facility by an equal amount.

This revolving credit agreement contained various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also required us to satisfy certain financial covenants at the end of each fiscal quarter. We are in compliance with these covenants at December 31, 2004.

Tender offers for GulfTerra senior and senior subordinated notes

On August 4, 2004, in anticipation of completing the GulfTerra Merger, our Operating Partnership commenced four cash tender offers to purchase any and all of the outstanding senior and senior subordinated notes of GulfTerra having a total outstanding principal amount of approximately $921.5 million. In connection with the tender offers, GulfTerra executed supplements to the indentures governing these notes that eliminated certain restrictive covenants and default provisions contained in those indentures upon our purchase of more than a majority in principal amount of each series of the outstanding senior and senior subordinated notes.

Substantially all of the GulfTerra notes ($915 million of $921.5 million) were tendered pursuant to the tender offers. On September 30, 2004, we borrowed $1.1 billion under our 364-Day Acquisition Credit Facility in anticipation of completing the tender offers and placed these funds in escrow. On October 5, 2004, our Operating Partnership purchased the notes for a total price of approximately $1.1 billion, which included $27 million related to consent payments.

The following table shows the four GulfTerra senior debt obligations affected, including the principal amount of each series of notes tendered, as well as the payment made by Enterprise to complete the tender offers.

Description	Principal Amount Tendered	Cash Payments Made by Enterprise: Accrued Interest	Tender Price (1)	Total Paid
8.50% Senior Subordinated Notes due 2010				
(Represents 98.2% of principal amount outstanding)	$ 212,057	$ 6,209	$ 246,366	$ 252,575
10.625% Senior Subordinated Notes due 2012				
(Represents 99.9% of principal amount outstanding)	133,916	4,901	167,612	172,513
8.50% Senior Subordinated Notes due 2011				
(Represents 99.5% of principal amount outstanding)	319,823	9,364	359,379	368,743
6.25% Senior Notes due 2010				
(Represents 99.7% of principal amount outstanding)	249,250	5,366	274,073	279,439
Totals	$ 915,046	$ 25,840	$ 1,047,430	$ 1,073,270

(1) Tender price includes consent payment of $30 per $1,000 principal amount tendered.

Multi-Year Revolving Credit Facility. In August 2004, our Operating Partnership entered into a five-year $750 million revolving credit agreement that includes a sublimit of $100 million for standby letters of credit. This facility became effective concurrent with the closing of the GulfTerra Merger and will mature on September 30, 2009. This facility replaced our then existing $270 million Multi-Year Revolving Credit Facility and $230 million 364-Day Revolving Credit Facility, which were terminated upon the effective date of the new facility. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

As defined by the credit agreement, variable interest rates charged under this facility generally bear interest, at our election at the time of each borrowing, at (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate. This revolving credit agreement contains various covenants similar to those of our 364-Day Acquisition Credit Facility. We are in compliance with these covenants at December 31, 2004.

Senior Notes A, B, C and D. These fixed-rate notes are an unsecured obligation of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We were in compliance with these covenants at December 31, 2004. On March 15, 2005, we repaid the $350 million in indebtedness outstanding under Senior Notes A, using the proceeds we received from our issuance of Senior Notes I and J.

Senior Notes E, F, G and H. On September 23, 2004, our Operating Partnership priced a private offering of an aggregate of $2 billion in principal amount of senior unsecured notes in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended. On October 4, 2004, these notes were issued. The interest rate, principal amount and net proceeds, before expenses, for each senior note in this offering are shown in the following table:

Senior Note Issued	Fixed Interest Rate	Principal Amount	Bond Discount	Proceeds to Us, Before Expenses
Senior Notes E, due October 2007	4.000%	$ 500,000	$ 2,140	$ 497,860
Senior Notes F, due October 2009	4.625%	500,000	4,405	495,595
Senior Notes G, due October 2014	5.600%	650,000	4,784	645,216
Senior Notes H, due October 2034	6.650%	350,000	4,203	345,797
Totals		$ 2,000,000	$ 15,532	$ 1,984,468

The net proceeds from this offering were used to reduce debt amounts outstanding under the Operating Partnership's $2.25 billion 364-Day Acquisition Credit Facility that was used to partially fund the GulfTerra Merger on September 30, 2004.

These fixed-rate notes are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes were issued under an indenture containing certain covenants, which restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We are in compliance with these covenants at December 31, 2004.

On January 24, 2005, we filed a registration statement for an offer to exchange these notes for registered debt securities with identical terms. The exchange of notes was completed in March, 2005.

Senior Notes I and J. On February 15, 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a private offering, comprised of $250 million in principal amount of 10-year senior unsecured notes and $250 million in principal amount of 30-year senior unsecured notes. The 10-year notes ("Senior Notes I") were issued at 99.379% of their principal amount and have fixed-rate interest of 5.00% and a maturity date of March 1, 2015. The 30-year notes ("Senior Note J") were issued at 98.691% of their principal amount and have fixed-rate interest of 5.75% and a maturity date of March 1, 2035. The Operating Partnership used the net proceeds from the issuance of Senior Notes I and J to repay $350 million of indebtedness outstanding under Senior Notes A which was due on March 15, 2005, and the remaining proceeds for general partnership purposes, including the temporary repayment of indebtedness outstanding under the Multi-Year Revolving Credit Facility.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, our Operating Partnership entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by us through an unsecured and unsubordinated guarantee. The Pascagoula MBFC Loan contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility. We were in compliance with the covenants at December 31, 2004.

The indenture agreement for this loan contains an acceleration clause whereby if our credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or below, the $54 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Industrial Development Revenue Bonds. In April 2004, Petal Gas Storage L.L.C. ("Petal"), a wholly owned subsidiary of GulfTerra, borrowed $52 million from the Mississippi Business Finance Corporation ("MBFC") pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52 million in Industrial Development Revenue Bonds to another wholly owned subsidiary of GulfTerra. The loan agreement and the Industrial Development Revenue Bonds have identical fixed interest rates of 6.25% and maturities of fifteen years. The bonds and the associated tax exemptions are authorized under the Mississippi Business Finance Act. Petal may repay the loan agreement without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $2.2 million on our Consolidated Balance Sheet as of December 31, 2004. Beginning in the fourth quarter of 2004, we also netted the interest expense and interest income amounts of $0.8 million attributable to these instruments on our Statements of Consolidated Operations. Our presentation of the Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, "*Offsetting of Amounts Related to Certain Contracts*", and SFAS No. 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*", since we have the ability and intent to offset these items.

Loss due to write-off of unamortized debt issuance costs. As a result of terminating our 364-Day Revolving Credit Facility and our previous Multi-Year Revolving Credit Facility on September 30, 2004, we expensed $0.7 million of unamortized debt issuance costs.

Information Regarding Variable Interest Rates Paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations during 2004.

	Range of interest rates paid	Weighted-average interest rate paid
Interim Term Loan (terminated May 2004)	1.72% to 1.78%	1.76%
364-Day Revolving Credit Facility (terminated September 30, 2004)	1.72% to 4.00%	1.82%
Multi-Year Revolving Credit Facility (terminated September 30, 2004)	1.67% to 4.25%	1.83%
364-Day Acquisition Credit Facility (effective September 30, 2004)	2.67% to 4.75%	3.50%
Multi-Year Revolving Credit Facility (effective September 30, 2004)	2.64% to 5.25%	3.06%

Consolidated Debt Maturity Table

The following table shows scheduled maturities of the principal amounts of our debt obligations for the next 5 years and in total thereafter.

Fiscal 2005	$ 15,000
" 2007	500,000
" 2009	821,000
Thereafter	2,952,698
Total scheduled principal to be repaid	$ 4,288,698

In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*", the amount shown in the table above for 2005 excludes the $242.2 million principal amount due under our 364-Day Acquisition Credit Facility at December 31, 2004. We refinanced this short-term obligation using proceeds from an equity offering completed in February 2005. As a result, we have reclassified this amount to long-term debt and shown it as a component of principal amounts due after 2009.

In addition, the long-term portion of our debt obligations at December 31, 2004 reflects our refinancing of the $350 million in principal amount Senior Notes A (due March 2005) with proceeds from our issuance in March 2005 of $250 million in principal amount Senior Notes I (due March 2015) and our $250 million in principal amount Senior Notes J (due March 2035). In accordance with SFAS No. 6, the principal amount due under Senior Notes A has been reclassified to amounts due after 2009 to match the scheduled maturities of Senior Notes I and J.

Joint Venture Debt Obligations

We have ownership interests in four joint ventures having long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2004, (ii) total long-term debt obligations (including current maturities) of each unconsolidated affiliate at December 31, 2004, on a 100% basis to the joint venture and (iii) the corresponding scheduled maturities of such long-term debt (dollars in thousands).

	Our Ownership Interest	Total	Scheduled Maturities of Long-Term Debt 2005	2006	2007	2008	2009	After 2009
Cameron Highway [(1)]	50.0%	$ 297,000		$ 8,125	$ 32,500	$ 164,375	$ 16,000	$ 76,000
Deepwater Gateway	50.0%	144,000	$ 22,000	22,000	22,000	22,000	56,000	
Poseidon	36.0%	107,000				107,000		
Evangeline	49.5%	35,650	5,000	5,000	5,000	5,000	5,000	10,650
Total		$ 583,650	$ 27,000	$ 35,125	$ 59,500	$ 298,375	$ 77,000	$ 86,650

(1) The scheduled maturities for Cameron Highway assume that the construction loan will be converted into a term loan by July 2005 and scheduled repayments will begin on December 31, 2006.

The following is a summary of the significant aspects of the debt obligations of our unconsolidated affiliates.

Cameron Highway. In July 2003, Cameron Highway entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, to finance a substantial portion of the cost to construct the Cameron Highway oil pipeline.

The construction loan bears interest at a variable rate. Once the Cameron Highway oil pipeline has commenced operations and transported a certain level of volumes (as specified in the credit agreement), the construction loan will convert to a term loan maturing in 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 $8.1 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by January 2006, the construction loan and senior secured notes become fully due and payable. At December 31, 2004, Cameron Highway had $197 million outstanding under its construction loan at an average interest rate of 5.48%.

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, 2004, Cameron Highway had $100 million outstanding under its senior secured notes at an average interest rate of 7.36%.

The project loan facility as a whole is secured by (1) substantially all of Cameron Highway's assets, including, upon conversion to a term loan, 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, 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.

Deepwater Gateway. In August 2002, Deepwater Gateway, our unconsolidated affiliate which owns the Marco Polo tension-leg platform, obtained a $155 million project finance loan to finance a substantial portion of the cost to construct the Marco Polo tension-leg platform and related facilities. Construction of the Marco Polo tension-leg platform was completed during the first quarter of 2004, and in June 2004, Deepwater Gateway converted the project finance loan into a term loan which matures in June 2009. The term loan is payable in twenty equal quarterly installments of $5.5 million each (which began on September 30, 2004), and the remaining outstanding principal of $45 million is due on the maturity date. Interest rates are variable and the loan is collateralized by substantially all of Deepwater Gateway's assets. Deepwater Gateway is 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. If Deepwater Gateway defaults on its payment obligations under the term loan, we would be required to pay the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2004, the average interest rate charged under this term loan was 4.42%.

In accordance with terms of the credit agreement, Deepwater Gateway has the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway has decided to extinguish its term loan. We and our 50% joint venture partner in Deepwater Gateway, Cal Dive, will make equal cash contributions to Deepwater Gateway to fund the repayment. At March 9, 2005, the term loan principal amount owed by Deepwater Gateway was $144 million.

Poseidon. Poseidon is party to a $170 million revolving credit facility which matures in January 2008. The interest rates Poseidon is charged on balances outstanding under its revolving credit facility are variable and depend on its ratio of total debt to earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon's assets. As of December 31, 2004, the average interest rate charged under Poseidon's revolving credit facility was 4.58%.

Evangeline. At December 31, 2004, long-term debt for Evangeline consisted of (i) $28.2 million in principal amount of 9.9% fixed-rate Series B senior secured notes that are due in December 2010 and (ii) a $7.5 million subordinated note payable. The Series B senior secured notes are collateralized by Evangeline's property, plant and equipment; proceeds from a gas sales contract; and by a debt service requirement. Scheduled principal repayments on the Series B notes are $5 million annually through 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios. Evangeline incurred the subordinated note payable in connection with its acquisition of a contract-based intangible asset in the early 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders are either fully cash secured through debt service accounts or have been completely repaid. In general, interest accrues on the subordinated note at a variable-rate based on LIBOR plus ½%. The variable interest rate paid on this debt at December 31, 2004 was 1.73%.

CREDIT RATINGS

Our current corporate credit ratings are Baa3 (investment grade) with a stable outlook as rated by Moody's Investor Services; BB+ (non-investment grade) with a positive outlook as rated by Standard and Poor's and BBB- (investment grade) with a stable outlook by Fitch ratings.

Depending on our future operating results, these credit rating agencies may view our current levels of debt negatively. If one or more of these credit rating agencies were to downgrade our credit standing, we could experience an increase in our borrowing costs, difficulty accessing capital markets or a reduction in the market price of our common units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures, acquisitions and to refinance indebtedness.

Additionally, if our credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or below, the $54 million principal balance of our Pascagoula MBFC Loan, and all related accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, we would have to redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under the Pascagoula MBFC Loan.

CAPITAL SPENDING

We have a number of ongoing capital projects, including those we assumed as a result of the GulfTerra Merger (please read "- *Significant Announced Growth Capital Projects*" on page 44 of this annual report). For the years ended December 31, 2004, 2003 and 2002, our capital spending for business combinations (including non-cash consideration amounts), property, plant and equipment and our unconsolidated affiliates was $3.8 billion, $655.2 million and $1.7 billion, respectively. The following table summarizes our capital spending by activity for the periods indicated:

	For Year Ended December 31,		
	2004	**2003**	**2002**
Capital spending for business combinations:			
GulfTerra Merger (Step Two transactions):			
Cash payments to El Paso	$ 500,000		
Transaction fees and other direct costs	24,032		
Cash received from GulfTerra	(40,313)		
Net cash payments	483,719		
Value of non-cash consideration issued or granted	2,910,771		
Total GulfTerra Merger Step Two consideration	3,394,490		
GulfTerra Merger (Step Three transactions):			
Cash payments to El Paso	155,277		
Mid-America and Seminole pipelines			$ 1,182,946
Propylene fractionation and hydrocarbon storage assets			368,636
Other business combinations	85,851	$ 37,348	69,145
Total capital spending related to business combinations	3,635,618	37,348	1,620,727
Capital spending for property, plant and equipment:			
Growth capital projects	114,419	125,600	64,934
Sustaining capital projects	32,509	20,313	7,201
Total capital spending for property, plant and equipment	146,928	145,913	72,135
Capital spending attributable to unconsolidated affiliates:			
Investments in and advances to unconsolidated affiliates	64,412	471,927	13,651
Total capital spending	$ 3,846,958	$ 655,188	$ 1,706,513

The preceding table reflects capital spending of $3.5 billion for the GulfTerra Merger in 2004; $425 million for our investment in GulfTerra GP in 2003; and $1.2 billion for our acquisition of the Mid-America and Seminole pipelines in 2002. Our capital spending for property, plant and equipment is reflected net of contributions in aid of construction of $8.9 million, $0.9 million and $4 million during 2004, 2003 and 2002, respectively.

We are committed to the long-term growth and viability of the Company. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. In recent years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures. Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. We believe that we are positioned to continue to grow through acquisitions that will expand our system of assets and through growth capital projects. The combination of our operations with those of GulfTerra provides us with incremental growth opportunities for both onshore and offshore projects. We currently estimate that our capital spending over the next two to three years could approximate up to $2 billion, primarily for growth projects in the Gulf of Mexico and Western regions of North America. Of this amount, we expect to spend approximately $970 million during 2005.

The ability to execute our growth strategy and complete our projects is dependent upon our access to the capital necessary to fund 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.

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to provide capital from operating cash flows 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 or decisions to take on additional partners.

As previously noted, we estimate our capital spending for property, plant and equipment during 2005 to approximate $970 million, which includes estimated expenditures of $900 million for growth capital projects and acquisitions and approximately $70 million for sustaining capital expenditures, which result from improvements to and major renewals of existing assets. The following table summarizes our forecasted expenditures during 2005 for announced acquisitions and significant growth capital projects (in millions of dollars):

Growth Capital Projects:	
Independence Hub Platform	$ 160.3
Independence Trail Pipeline System	159.8
Constitution Gathering System	126.7
San Juan Optimization Project	30.0
NGL Expansion Projects	29.7
Iso-Octane Conversion Project	12.7
Petal Conversion Project	11.9
Acquisitions:	
Additional interests in Dixie Pipeline Company [(1)]	70.9
Indian Springs natural gas gathering and processing assets [(1)]	74.5
Total	$ 676.5

(1) For information regarding these acquisitions, please read "Recent Developments," on page 19 of this annual report.

We also expect to invest approximately $7.5 million in the capital projects of our unconsolidated affiliates during 2005. As of December 31, 2004, we had approximately $70 million in outstanding purchase commitments related to our share of capital projects, the majority of which pertain to pipeline and platform growth projects in the Gulf of Mexico.

Significant Announced Growth Capital Projects

Prior to the GulfTerra Merger, GulfTerra had a number of midstream energy projects underway. In addition, we have announced various new growth capital projects that are currently underway. The following is a discussion of our significant growth capital projects, including those acquired with in the GulfTerra Merger:

Independence Hub Platform and Independence Trail Pipeline System. In November 2004, we entered into an agreement with the Atwater Valley Producers Group (consisting of Anadarko, Dominion, Kerr-McGee, Spinnaker and Devon) for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas (collectively, the "anchor fields") of the deepwater Gulf of Mexico. We will design, construct, and own Independence Hub, a 105-foot deep-draft, semi-submersible platform with a two-level production deck, which will be capable of processing 850 MMcf/d of natural gas. The platform, which is estimated to cost approximately $385 million, will be operated by Anadarko, and is designed to process production from its anchor fields and has excess payload capacity to support ten additional pipeline risers. In December 2004, we entered into an agreement with Cal Dive to sell them a 20% indirect interest in the Independence Hub platform. Under the terms of the agreement, we will have access to Cal Dive's fleet of vessels, which will assist us in the construction of the Independence Hub platform and the related export pipeline.

The Independence Hub platform will be located on Mississippi Canyon Block 920, in a water depth of 8,000 feet. This location was selected for the permanently anchored platform based on favorable seafloor conditions and proximity to the identified anchor fields. First production is expected in 2007. Under the terms of the agreement, the production fields served by the Independence Hub platform will include the dedicated anchor fields in addition to future discoveries on surrounding undeveloped blocks.

Additionally, we will construct, own, and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of approximately 850 MMcf/d of natural gas. The pipeline system, which is estimated to cost $280 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline. We entered into an agreement with Tennessee Gas Pipeline under which they will pay us $15 million for contributions in aid of construction to connect the Independence Trail natural gas pipeline system to their pipeline system. In November 2004, Tennessee Gas Pipeline reimbursed us $7 million for construction costs incurred. The balance of $8 million would be reimbursed by Tennessee Gas Pipeline when additional costs are incurred and is contingent upon our completion of the Independence Trail project, which is expected during 2006.

Constitution Gathering System. In July 2004, GulfTerra entered into a definitive agreement to construct, own, and operate oil and natural gas pipelines to provide production gathering services for the Constitution field, which is 100% owned by Kerr-McGee. The Constitution field is located at a depth of 5,300 feet in Green Canyon Blocks 679 and 680 in the Central Gulf of Mexico. The new $53.4 million natural gas pipeline will be a 32-mile, 16-inch pipeline with a transport capacity of up to 200 MMcf/d and will connect to our existing Anaconda Gathering System. The new $76.2 million oil pipeline will be a 70-mile, 16-inch pipeline with a minimum transport capacity of 80 MBPD that will connect with the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at our Ship Shoal 332B platform. These pipelines are expected to start transporting volumes in the first half of 2006.

San Juan Optimization Project. In May 2003, we commenced a project relating to our San Juan Basin assets. This project, which is estimated to cost approximately $43 million, is expected to be completed in stages through 2006 and will result in increased capacity of up to 130 MMcf/d on our San Juan natural gas gathering system and increased market opportunities through a new interconnect at the tailgate of our Chaco plant.

Rocky Mountain NGL pipeline expansion and related NGL fractionation projects. In January 2005, we started a project to expand our Mont Belvieu NGL fractionator to accommodate increased production of NGLs being transported to Mont Belvieu from the Rocky Mountain area. Our Mont Belvieu facility's current fractionation capacity is up to 210 MBPD of mixed NGLs. This project, which is expected to be completed in the first quarter of 2006 at an estimated total cost of $34.2 million, will increase total fractionation capacity at this facility by 15 MBPD and reduce its energy costs. Additionally, we are reviewing a proposal to construct a new NGL fractionator at our Mont Belvieu complex that could add an additional 60 MBPD of fractionation capacity at this industry hub.

Currently, the Rocky Mountain segment of our Mid-America pipeline system transports up to 225 MBPD of NGLs from the major producing basins in Wyoming, Utah, Colorado and New Mexico to the Hobbs station on the Texas-New Mexico border. The Western Expansion Project would increase the capacity of this pipeline to 275 MBPD. Permitting, engineering and design work are in progress. We submitted a draft environmental assessment and plan of development to the appropriate regulatory agencies during the first quarter of 2005. Contingent upon receiving all required permits and regulatory approvals, construction could begin as early as the fourth quarter of 2005.

Iso-Octane Conversion Project. As a result of environmental concerns related to MTBE, we are currently in the process of modifying our BEF facility to produce iso-octane, a motor gasoline octane enhancement additive derived from isobutane. We expect iso-octane to be in demand by refiners to replace the amount of octane that is lost as a result of MTBE being eliminated as a motor gasoline blendstock. Depending on the outcome of various factors (including pending federal legislation) the facility may be further modified in the future to produce alkylate.

Petal Conversion Project. In the third quarter of 2004, we began to convert an existing brine well at our existing propane storage complex in Hattiesburg, Mississippi to natural gas service. This conversion, which is expected to cost $18 million, will create a new natural gas storage cavern with 1.8 Bcf of working gas capacity that will be integrated with our existing Petal natural gas storage facility. We expect to have the cavern in service during the second quarter of 2005. We have executed long-term storage agreements with BP for the entire capacity of the new natural gas storage cavern.

Purchase Options Associated with Retained Leases

EPCO contributed various equipment leases to us at our formation in 1998 for which EPCO has retained the cash payment obligations (the "retained leases"). EPCO has assigned to us the purchase options associated with the retained leases. During 2003, we exercised our option to purchase an isomerization unit and in October 2004 purchased the unit at a cost of $15 million, which approximated fair value. Additionally, in December 2004, we purchased equipment related to the isomerization unit for $2.8 million pursuant to our purchase option. Should we decide to exercise the remaining purchase options associated with the retained leases (which are also at fair value), an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs. In connection with the new regulations for hazardous liquid pipelines, we developed a pipeline integrity management program in 2002. In connection with the new regulations for natural gas pipelines, we developed a pipeline integrity management program in 2004.

During 2004, we spent approximately $22.4 million to comply with these new regulations, of which $12.2 million was recorded as an operating expense of our NGL Pipelines & Services segment and $2.7 million was recorded as an operating expense of our Onshore Natural Gas Pipelines & Services segment. The remaining $7.5 million we spent to comply with the new regulations was capitalized. Based on information currently available, our cash outlays for our pipeline integrity program associated with these new regulations are estimated to be approximately $50.3 million for 2005.

The forecasted cost for 2005 is net of an indemnification we will receive from El Paso. In April 2002, GulfTerra acquired several midstream assets located in Texas and New Mexico from El Paso (the "EPN Holdings" acquisition). The assets acquired included the Texas Intrastate System, the Permian Basin System and the Indian Basin gas processing facility. Pursuant to an amended purchase and sale agreement between GulfTerra and El Paso for these assets, El Paso agreed to indemnify GulfTerra against all pipeline integrity costs incurred (whether paid or payable) with respect to the assets acquired in the EPN Holdings acquisition for each of the years ending December 31, 2005, 2006 and 2007, to the extent that such annual costs exceed $3.3 million; however, the amount reimbursable by El Paso for 2005, 2006 and 2007 shall not exceed $50.2 million.

OUR CONTRACTUAL OBLIGATIONS

The following table summarizes our contractual obligations at December 31, 2004 (dollars in thousands):

Contractual Obligations	Total	Less than 1 year (2005)	1-3 years (2006 – 2007)	3-5 years (2008 – 2009)	More than 5 years (Beyond 2009)
	Payment or Settlement due by Period				
Scheduled maturities of long-term debt (1)	$ 4,288,698	$ 15,000	$ 500,000	$ 821,000	$ 2,952,698
Estimated cash payments for interest (2)	$ 2,666,248	$ 217,925	$ 413,253	$ 370,276	$ 1,664,794
Operating lease obligations (3)	$ 88,899	$ 15,012	$ 25,622	$ 14,914	$ 33,351
Purchase obligations: (4)					
Product purchase commitments: (5)					
Estimated payment obligations:					
Natural gas	$ 1,160,829	$ 165,120	$ 284,266	$ 284,655	$ 426,788
NGLs	$ 174,281	$ 42,664	$ 21,936	$ 21,936	$ 87,745
Petrochemicals	$ 1,791,983	$ 1,010,907	$ 774,828	$ 6,248	
Other	$ 166,706	$ 41,706	$ 62,271	$ 46,845	$ 15,884
Underlying major volume commitments:					
Natural gas (in BBtus)	149,705	21,855	36,500	36,550	54,800
NGLs (in MBbls)	5,657	1,267	732	732	2,926
Petrochemicals (in MBbls)	27,294	15,559	11,646	89	
Service payment commitments (6)	$ 7,580	$ 4,906	$ 2,674		
Capital expenditure commitment (7)	$ 69,288	$ 69,288			
Other long-term liabilities, as reflected on our Consolidated Balance Sheet (8)	$ 63,521		$ 15,846	$ 10,385	$ 37,290

(1) We have long and short-term payment obligations under credit agreements such as our senior notes and revolving credit facilities. Amounts shown in the table represent our scheduled future maturities of long-term debt principal (including current maturities) for the periods indicated. In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*," the scheduled maturities of debt presented in the table reflect (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment of our 364-Day Acquisition Credit Facility using proceeds from an equity offering completed in February 2005. For additional information regarding our debt obligations, please read "*Our Liquidity and Capital Resources – Our Debt Obligations*" on page 36 of this annual report.

(2) Amounts shown in the table above represent our estimated cash interest payments for long-term debt (including current maturities thereof) for the periods indicated.

(3) We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum lease payment obligations under our third-party operating leases with terms in excess of one year for the periods indicated. For addition information regarding our operating lease commitments, please read Note 16 of the Notes to Consolidated Financial Statements on page 118 of this annual report.

(4) We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions.

(5) We have long and short-term product purchase obligations for NGLs, petrochemicals and natural gas with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. Amounts shown in the table represent our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2004 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery.

(6) We have long and short-term commitments to pay third-party service providers for services such as maintenance agreements. Our contractual payment obligations vary by contract. The table shows our future payment obligations under these service contracts.

(7) We have short-term payment obligations relating to capital projects we have initiated and are also responsible for our share of such obligations associated with the capital projects of our unconsolidated affiliates. These commitments represent unconditional payment obligations that we or our unconsolidated affiliates have agreed to pay vendors for services rendered or products ordered.

(8) We have recorded long-term liabilities on our balance sheet reflecting amounts we expect to pay in future periods beyond one year. These liabilities primarily relate to reserves for asset retirement obligations, environmental liabilities and other amounts. Amounts shown in the table represent our best estimate as to the timing of payments based on available information.

The operating lease commitments shown in the preceding table exclude the non-cash, related party expense associated with various equipment leases contributed to us by EPCO at our formation for which EPCO has retained the liability (the "retained leases"). The retained leases are accounted for as operating leases by EPCO. EPCO's minimum future rental payments under these leases are $2.1 million for each of the years 2005 through 2008, $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016.

RECENT ACCOUNTING DEVELOPMENTS

FIN 46, "*Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51*." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements. Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-06, "*Participating Securities and the Two-Class Method under SFAS No. 128*." This accounting guidance, which is applicable for the period beginning April 1, 2004, requires the two-class method for calculating earnings per share for certain securities that are considered to participate in earnings with common shareholders. Under the two-class method, distributions to equity owners are subtracted from earnings, and any remaining earnings would be allocated to the various classes of owners in proportion to their right to receive distributions as if those earnings had been distributed. The total distributions to each class of owner plus the amount allocated to each class would be used to compute earnings per unit for that class. Since our distributions to owners exceeded earnings during the periods presented, as has historically been the case, the two-class method did not produce any change from the way we have traditionally computed earnings per unit. As a result, our adoption of this standard had no effect on our earnings per unit calculations.

SFAS *No. 151, "Inventory Costs — an Amendment of ARB No. 43, Chapter 4."* This accounting guidance, which is applicable for fiscal years beginning after June 15, 2005, amends ARB No. 43, Chapter 4, to clarify that abnormal amounts of idle facility expense, freight, handling costs and wasted materials (spoilage) should be recognized as current period charges. It also requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. We do not expect the adoption of SFAS No. 151 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 123(R), "Share-Based Payment." This accounting guidance, which is applicable for the first interim or annual reporting period beginning after June 15, 2005, replaces SFAS No. 123, "*Accounting for Stock-Based Compensation*" and supersedes APB No. 25, "*Accounting for Stock Issued to Employees*." This Statement eliminates the ability to account for share-based compensation transactions using APB No. 25, and generally requires instead that such transactions be accounted for using a fair-value-based method.

This statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award - the requisite service period (usually the vesting period). No compensation cost is recognized for equity instruments for which employees do not render the requisite service. Employee share purchase plans will not result in recognition of compensation cost if certain conditions are met; those conditions are much the same as the related conditions in SFAS No. 123.

A public entity will initially measure the cost of employee services received in exchange for an award of liability instruments based on its current fair value; the fair value of that award will be remeasured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period.

The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments (unless observable market prices for the same or similar instruments are available). If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification.

We are continuing to evaluate the provisions of SFAS No. 123(R) and will fully adopt the standard during 2005 within the prescribed time periods. Upon the required effective date, we will apply this statement using a modified version of prospective application as described in the standard.

OUR CRITICAL ACCOUNTING POLICIES

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk underlying our most significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. We use the straight-line method to depreciate the majority of our property, plant and equipment, which results in depreciation expense being incurred evenly over the life of the assets. We estimate depreciation based on the estimated useful lives and residual values of our assets. As of the time we place our assets in service, we believe our estimates are accurate. However, circumstances in the future may develop which would cause us to change these estimates and in turn would change our depreciation amounts on a going forward basis. Some of these circumstances include changes in laws and regulations relating to restoration and abandonment requirements; changes in 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.

At December 31, 2004 and 2003, the net book value of our property, plant and equipment was $7.8 billion and $3 billion, respectively. We recorded $161 million and $101 million in depreciation expense during 2004 and 2003, respectively. A significant portion of the year-to-year increase in depreciation expense for 2004 and 2003 is attributable to the property, plant and equipment assets we acquired in the GulfTerra Merger, which were recorded at their preliminary fair values upon completion of the GulfTerra Merger at September 30, 2004. For additional information regarding our property, plant and equipment, please read Notes 1 and 6 of the Notes to Consolidated Financial Statements on pages 70 and 86 of this annual report.

Measuring recoverability of long-lived assets and equity method investments

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, oil or NGLs. Long-lived assets with recorded values that are not expected to be recovered through future expected cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated margins and volumes; estimated useful life of the asset or asset group; and salvage values. An impairment charge would be recorded for the excess of the long-lived asset's carrying value and its fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows but incorporating probabilities that reflect a range of possible outcomes and market value and replacement cost estimates.

Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. Examples of such events or changes include continued operating losses of the investee or long-term negative changes in the investee's industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment.

Due to a deteriorating business environment, BEF evaluated the carrying value of its long-lived assets for impairment during the third quarter of 2003. This review indicated that the carrying value of its long-lived assets exceeded their collective fair value, which resulted in a non-cash impairment charge of $67.5 million. Since BEF was one of our equity investments at that time, our share of this loss was $22.5 million and was recorded as a component of equity in income (loss) of unconsolidated affiliates on our 2003 Statement of

Consolidated Operations. As a consolidated subsidiary, BEF continues to review its operations on quarterly basis due to the challenging and uncertain business environment in which it operates.

In order to complete the GulfTerra Merger, the FTC required us to sell our interest in a Mississippi propane storage facility in which we owned a 50% interest. As a result of our determination of this long-lived asset's current market value, we recorded a $4 million non-cash asset impairment charge during the third quarter of 2004, which is reflected as a component of operating costs and expenses on our 2004 Statement of Consolidated Operations.

Additionally, during 2003 we recorded a $1.2 million asset impairment charge related to our Petal NGL fractionator. This non-cash amount is a component of operating costs and expenses as shown on our 2003 Statement of Consolidated Operations. The Petal NGL fractionation facility was decommissioned in December 2003 after management decided that this older facility did not fit into our long-range plans due to poor economics of continued operations at the site. We continue to own this facility, the carrying value of which has been adjusted to its fair value of approximately $0.1 million.

Amortization methods and estimated useful lives of qualifying intangible assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property, such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The approach to the valuation of each intangible asset will vary depending upon the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate. Our recorded intangible assets primarily include the estimated value assigned to certain customer relationships and contract-based assets.

Our customer relationship intangible assets represent the customer base that GulfTerra and the South Texas midstream assets serve through providing services, including natural gas gathering and processing, NGL fractionation and pipeline transportation. These entities conduct the majority of their business through the use of written contracts; thus, the customer relationships represent the rights we own arising from these contractual agreements. The value of these customer relationships are being amortized using expected production curves associated with the underlying resource bases (i.e., the oil and gas reserves associated with the intangible assets). Our estimate of the economic life of each resource base is based on a number of factors, including third-party reserve estimates, the economic viability of production and exploration activities and other industry factors.

Our contract-based intangible assets represent the rights we own arising from contractual agreements in the natural gas and NGL storage operations. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life, which is the period over which the asset is expected to contribute directly or indirectly to the future cash flows of an entity based on the respective contract terms. Our estimate of useful life is also based on a number of factors, including (1) the expected use of the asset by the entity, (2) the expected useful life of the related assets (i.e., fractionation facility, pipeline, etc.), (3) any legal, regulatory or contractual provisions, including renewal or extension periods that would cause substantial costs or modifications to existing agreements, (4) the effects of obsolescence, demand, competition, and other economic factors and (5) the level of maintenance required to obtain the expected future cash flows.

If our underlying assumptions regarding the useful life or the economic life of the resource base associated with an intangible asset change (either favorably or unfavorably), then we may be required to adjust the amortization period of such asset to reflect any new estimate of its useful life or economic life of the resource base. Such a change would increase or decrease the annual amortization charge associated with the asset at that time. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset or economic life of the resource base associated with the asset. Any such write-down of the value and unfavorable change in the useful life or economic life associated with the resource base (i.e., amortization period) of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2004 and 2003, the carrying value of our intangible asset portfolio was $980.6 million and $268.9 million.   We recorded $33.8 million and $14.8 million in amortization expense associated with our intangible assets during 2004 and 2003, respectively. A significant portion of the year-to-year increase in amortization expense for 2004 and 2003 is attributable to the intangible assets we acquired in the GulfTerra Merger, which were recorded at their preliminary fair values upon completion of the GulfTerra Merger at September 30, 2004.   For additional information regarding our intangible assets, please read Notes 1 and 8 of the Notes to Consolidated Financial Statements on pages 70 and 93 of this annual report.

Methods we employ to measure the fair value of goodwill

Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired and is primarily comprised of $376.8 million associated with the GulfTerra Merger which occurred on September 30, 2004, and $73.7 million associated with the purchase of propylene fractionation assets from Diamond-Koch in February 2002. Goodwill is not amortized. Instead, goodwill is tested for impairment at a reporting unit level annually, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. The testing of goodwill involves calculating the fair value of a reporting unit, which in turn is based on our assumptions regarding the future economic prospects of the reporting unit. If the fair value of the reporting unit (including related goodwill) is less than its book value, a charge to earnings would be required to reduce the carrying value of goodwill to its implied fair value. If our underlying assumptions regarding the future economic prospects of a reporting unit change, this could further impact the fair value of the reporting unit and result in an additional charge to earnings to reduce the carrying value of goodwill.

At December 31, 2004 and 2003, the carrying value of our goodwill was $459.2 million and $82.4 million. As a result of the GulfTerra Merger, the preliminary value allocated to goodwill is subject to change. For additional information regarding our goodwill, please read Notes 1 and 8 of the Notes to Consolidated Financial Statements included on pages 70 and 93 of this annual report.

Our revenue recognition policies and use of estimates for revenues and expenses

In general, we recognize revenue from our customers when all of the following criteria are met (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. When the contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), a determination of the necessity of an allowance is made and recorded accordingly. Historically, the consolidated revenues we recorded were not materially based on estimates.

However, our use of estimates for revenues, as well as our use of estimates for operating costs and other expenses has increased as a result of SEC regulations which require us to submit financial information on increasingly accelerated time frames. Such estimates are necessary due to the timing of compiling actual billing information and receiving third-party data needed to record transactions for financial reporting purposes. One example of such use of estimates is the accrual of an estimate of revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related information for the subject period). This accrual reverses in the following month and is offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, there is one month of estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and 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. If the basis of our estimates proves incorrect, it could result in material adjustments in results of operations between periods.

Reserves for environmental matters

Each of our business 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. We currently have a reserve for environmental matters related to remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with the GulfTerra Merger. 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. 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 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.

At December 31, 2004, we had a liability for environmental remediation of $21 million, which was derived from a range of reasonable estimates based upon studies and site surveys. In accordance with SFAS No. 5 "*Accounting for Contingencies*" and FASB Interpretation No. 14, "*Reasonable Estimation of the Amount of a Loss*," we recorded our best estimate of the loss.

Natural gas imbalances

Natural gas imbalances result when a customer delivers more or less gas into our pipelines than they take out. We generally value our imbalances using a twelve-month moving average of natural gas prices, which we believe is an appropriate assumption to estimate the value of the imbalances at the time of settlement given that the actual settlement dates are generally not known. Changes in natural gas prices may impact our estimates. Prior to the GulfTerra Merger, natural gas imbalances were not significant.

At December 31, 2004, our imbalance receivables were $56.7 million and are reflected as a component of accounts receivable. At December 31, 2004, our imbalance payables were $59 million and are reflected as a component of accrued gas payables.

RELATED PARTY TRANSACTIONS

The following information highlights our relationships with EPCO, Shell and our unconsolidated affiliates. For additional information regarding our relationships with these entities, please read page 113 of this annual report.

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of Enterprise GP are employees of EPCO, including Robert G. Phillips who is Chief Executive Officer and a director of Enterprise GP. For a listing of our directors and executive officers, please read page 137 of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of members of Mr. Duncan's family. In addition, at December 31, 2004, EPCO and Dan Duncan LLC, together, owned 90.1% of the membership interests of Enterprise GP, which in turn owns a 2% general partner interest in us. In January 2005, an affiliate of EPCO, Enterprise GP Holdings L.P., acquired El Paso's 9.9% membership interest in Enterprise GP. As a result of this transaction, EPCO and its affiliates own 100% of Enterprise GP.

In addition, trust affiliates of EPCO (the 1998 Trust and 2000 Trust), owned 11,387,615 of our common units at March 15, 2005. Collectively, Mr. Duncan, through his beneficial ownership of our common units held personally, by the 1998 and 2000 Trusts and through subsidiaries of EPCO, controlled approximately 37% of our common units at March 15, 2005.

The principal business activity of Enterprise GP is to act as our managing partner. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative and Services Agreement. We reimburse EPCO for the costs associated with employees who work on our behalf. We have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products. In addition, we sell NGL products to EPCO's Canadian affiliate. During 2004, our related party revenues from EPCO were $2.7 million and our related party expenses with EPCO were $230.7 million.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At March 15, 2005, Shell owned approximately 9.5% of our common units. Shell is one of our largest customers. For the years ended December 31, 2004, 2003 and 2002, Shell accounted for 6.5%, 5.5% and 7.9%, respectively, of our consolidated revenues. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell. We also lease from Shell its 45.4% interest in one of our propylene fractionation facilities located in Mont Belvieu. During 2004, our related party revenues from Shell were $542.9 million and our related party expenses with Shell were $725.4 million.

The most significant contract affecting our natural gas processing business is the Shell margin-band/keepwhole processing agreement, which grants us the right to process Shell's current and future production within state and federal waters of the Gulf of Mexico. We have also completed a number of business acquisitions and asset purchases involving Shell since 1999. For additional information regarding our relationship with Shell, please read Note 14 on page 113 of this annual report.

Relationships with unconsolidated affiliates

Our investment in unconsolidated affiliates with industry partners is a vital component of our business strategy. These investments are a means by which we conduct our operations to align our interests with a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. During 2004, related party revenues from our unconsolidated affiliates were $258.5 million and related party expenses with the unconsolidated affiliates were $37.6 million.

On occasion, we enter into management agreements with some of our unconsolidated affiliates under which our unconsolidated affiliates pay us management fees for the operation and management of their assets. However, these fees are not material to our consolidated results of operations. Additionally, on occasion we pay for construction costs on behalf of our unconsolidated affiliates during the initial construction phase of their assets, and these amounts are settled by direct reimbursements for the amounts we are owed from our unconsolidated affiliates.

OTHER ITEMS

Non-GAAP reconciliation. A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles (as shown on our Statements of Consolidated Operations and Comprehensive Income on page 66 of this annual report) follows:

	Year Ended December 31,		
	2004	**2003**	**2002**
Total non-GAAP gross operating margin	$ 655,191	$ 410,415	$ 332,349
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:			
Depreciation and amortization in operating costs and expenses	(193,734)	(115,643)	(86,028)
Retained lease expense, net in operating costs and expenses	(7,705)	(9,094)	(9,125)
Gain on sale of assets in operating costs and expenses	15,901	16	1
Selling, general and administrative costs	(46,659)	(37,590)	(42,890)
GAAP consolidated operating income	422,994	248,104	194,307
Other expense	(153,625)	(134,406)	(94,226)
GAAP income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 269,369	$ 113,698	$ 100,081

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year. These subleases (the "retained lease expense" in the previous table) are part of the Administrative Services Agreement that we executed with EPCO in connection with our formation in 1998. EPCO holds these items pursuant to operating leases for which it has retained the corresponding cash lease payment obligation.

Operating costs and expenses (as shown on the Statements of Consolidated Operations and Comprehensive Income included under Item 8 of this annual report) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the Company. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases. For additional information regarding the EPCO Administrative Services Agreement and the retained leases, please read Note 14 on page 113 of this annual report.

Cumulative effect of changes in accounting principles. As shown on our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004, the cumulative effect of changes in accounting principles represents the combined impact of (1) changing the method our BEF subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method and (2) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

Our BEF subsidiary owns an octane additive production facility that undergoes periodic planned outages of 30 to 45 days for major maintenance work. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services, and other related items. BEF used the accrue-in-advance method to record cost estimates for such activities; whereas, the Company's other operations used the expense-as-incurred method for their planned major maintenance activities. Our BEF subsidiary changed its accounting method on January 1, 2004 to conform to the Company's accounting for planned major maintenance costs, which better reflects expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

EITF 03-16, "*Accounting for Investments in Limited Liability Companies*," requires investments in limited liability companies that have separate ownership accounts for each investor be accounted for similar to limited partnerships under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), investors are required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3-5%) than the traditional 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Prior to July 1, 2004, we accounted for our 13.1% investment in VESCO using the cost method. As a result, we recognized dividend income from VESCO to the extent that we received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we recorded a cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in periods prior to July 1, 2004 and (ii) the dividend income from VESCO we recorded using the cost method in prior periods. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

For the periods indicated, the following table shows pro forma net income and earnings per unit amounts assuming the accounting changes noted above were applied retroactively to January 1, 2002. See Note 13 for information regarding the effect of the accounting changes on basic and diluted earnings per unit.

	For the Year Ended December 31,		
	2004	**2003**	**2002**
Pro Forma income statement amounts:			
Historical net income	$ 268,261	$ 104,546	$ 95,500
Adjustments to derive pro forma net income:			
Effect of change from the accrue-in-advance method to the expense-as-incurred method for BEF major maintenance costs:			
Remove historical equity in income (losses) recorded for BEF		31,508	(8,569)
Record equity in (income) losses from BEF calculated using new method of accounting for major maintenance costs		(31,800)	8,980
Remove cumulative effect of change in accounting principle recorded on January 1, 2004	(7,013)		
Remove minority interest expense associated with change in accounting principle - Sun 33.33% portion	2,338		
Effect of changing from the cost method to the equity method with respect to our investment in VESCO:			
Remove cumulative effect of change in accounting principle recorded on July 1, 2004	(3,768)		
Remove historical dividend income recorded from VESCO	(2,136)	(5,595)	(4,737)
Record equity earnings from VESCO	2,429	5,133	12,303
Pro forma net income	260,111	103,792	103,477
Enterprise GP interest	(36,945)	(20,708)	(10,743)
Pro forma net income available to limited partners	$ 223,166	$ 83,084	$ 92,734
Pro forma per unit data (basic):			
Historical units outstanding	265,511	199,915	155,454
Per unit data:			
As reported	$ 0.87	$ 0.42	$ 0.55
Pro forma	$ 0.84	$ 0.42	$ 0.60
Pro forma per unit data (diluted):			
Historical units outstanding	266,045	206,367	176,490
Per unit data:			
As reported	$ 0.87	$ 0.41	$ 0.48
Pro forma	$ 0.84	$ 0.40	$ 0.53

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings, fair values of certain debt instruments and cash flows resulting from changes in applicable interest rates or commodity prices. As a matter of policy, we do not use financial instruments for speculative (or "trading") purposes.

We recognize financial instruments as assets and liabilities on our Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings.

To qualify as a hedge, the item to be hedged must be exposed to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance regarding the implementation of this accounting standard. Since this guidance is still continuing, our conclusions about the application of SFAS No. 133 may be altered, which may result in adjustments being recorded in future periods as we adopt new FASB interpretations of this standard.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess the cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis models to forecast the expected impact of changes in interest rates on our future cash flows. Enterprise GP oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business climate.

Fair value hedges – Interest rate swaps. In January 2004, we entered into three interest rate swap agreements with an aggregate notional amount of $250 million in which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest. During the fourth quarter of 2004, we entered into six additional interest rate swap agreements with an aggregate notional amount of $600 million related to a portion of the principal outstanding under Senior Notes G issued on October 4, 2004.

Hedged Fixed Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 6.3%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 4.9%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.4%	$600 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these nine interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These nine agreements have a combined notional amount of $850 million and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we pay the counterparty a variable interest rate based on six-month LIBOR rates (plus an applicable margin as defined in each swap agreement) and receive back from the counterparty a fixed interest rate payment based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period"). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

Total fair value of the interest rate swaps in effect at December 31, 2004 was a receivable of approximately $0.5 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2004 reflects a $9.1 million benefit from these swap agreements.

The following tables show the effect of hypothetical price movements on the estimated fair value ("FV") of our interest rate swap portfolio and the related change in fair value of the underlying debt at the dates indicated (dollars in thousands):

Scenario	Resulting Classification	Swap FV at 12/31/04	Inc (Dec) in FV of Debt
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ 505	$ (505)
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(31,586)	32,091
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	32,596	(32,091)

Scenario	Resulting Classification	Swap FV at 03/02/05	Inc (Dec) in FV of Debt
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ (10,066)	$ 10,066
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(42,028)	31,963
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	21,897	(31,963)

The fair value of the interest rate swaps excludes the benefit we have already recorded in earnings. The change in fair value between December 31, 2004 and March 2, 2005 is primarily due to an increase in market interest rates relative to the forward interest rate curve used to determine the fair value of our financial instruments. The underlying floating LIBOR forward interest rate curve used to determine the March 2, 2005 fair values ranged from approximately 2.2% to 5.5% using 6-month reset periods ranging from October 2004 to October 2014.

Cash flow hedges – Forward starting interest rate swaps. During the first nine months of 2004, we entered into eight forward starting interest rate swap transactions having an aggregate notional amount of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these transactions was to effectively hedge the underlying U.S. treasury rate related to our anticipated issuance of $2 billion in principal amount of fixed rate debt. On October 4, 2004, our Operating Partnership issued $2 billion of private debt securities under Senior Notes E, F, G and H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS No. 133.

In April 2004, we elected to terminate the initial four forward starting swaps in order to manage and maximize the value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. In September 2004, we settled the remaining four swaps resulting in an $85.1 million payment to the counterparties. The net gain of $19.4 million from these settlements will be reclassified from Accumulated Other Comprehensive Income to reduce interest expense over the life of the associated debt.

The following table shows the notional amount covered by each forward starting swap and the cash gain (loss) associated with each swap upon settlement (dollars in thousands):

Term of Anticipated Debt Offering (or Forecasted Transaction)	**Notional Amount of Debt covered by Forward Starting Swaps**	**Net Cash Received upon Settlement of Forward Starting Swaps**
3-year, fixed rate debt instrument	$ 500,000	$ 4,613
5-year, fixed rate debt instrument	500,000	7,213
10-year, fixed rate debt instrument	650,000	10,677
30-year, fixed rate debt instrument	350,000	(3,098)
Total	$ 2,000,000	$ 19,405

Commodity risk hedging program

The prices of natural gas, NGLs and petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with natural gas and NGLs, we may enter into commodity financial instruments. The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas or NGLs. The commodity financial instruments we utilize may be settled in cash or with another financial instrument. Historically, we have not hedged our exposure to risks associated with petrochemical products, including MTBE.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by Enterprise GP. We may enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Enterprise GP oversees the strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis performed on this portfolio measures the potential income or loss (e.g., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the dates noted within the following table. In general, the quoted market prices used in the model are from those actively quoted on commodity exchanges (i.e., NYMEX) for instruments of similar duration. In those rare instances where prices are not actively quoted, we calculate forward price curves based on similar products which are actively quoted using regression equations with strong correlation factors.

The sensitivity analysis model takes into account the following primary factors and assumptions:

- the current quoted market price of natural gas;
- the current quoted market price of NGLs;
- changes in the composition of commodities hedged (i.e., the mix between natural gas and related NGLs);

- fluctuations in the overall volume of commodities hedged (for both natural gas and related NGL hedges outstanding);

- market interest rates, which are used in determining the present value; and

- a liquid market for such financial instruments.

An increase in fair value of the commodity financial instruments (based upon the factors and assumptions noted above) approximates the income that would be recognized if all of the commodity financial instruments were settled at the dates noted within the table. Conversely, a decrease in fair value of the commodity financial instruments would result in the recording of a loss.

The sensitivity analysis model does not include the impact that the same hypothetical price movement would have on the hedged commodity positions to which they relate. Therefore, the impact on the fair value of the commodity financial instruments of a change in commodity prices would be offset by a corresponding gain or loss on the hedged commodity positions, assuming:

- the commodity financial instruments function effectively as hedges of the underlying risk;

- the commodity financial instruments are not closed out in advance of their expected term; and

- as applicable, anticipated underlying transactions settle as expected.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, we may enter into a new commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

We had a limited number of commodity financial instruments in our portfolio at December 31, 2004. The following tables show the effect of hypothetical price movements on the estimated fair value ("FV") of this portfolio at the dates indicated (dollars in thousands):

Scenario	Resulting Classification	FV at 12/31/03	FV at 12/31/04	FV at 3/02/05
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 4	$ 219	$ (256)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	4	47	(703)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	4	391	191

At December 31, 2004, our portfolio primarily consisted of a limited number of natural gas cash flow and fair value hedges. We recorded $0.4 million of income related to our commodity hedging activities during 2004 and an expense of $0.6 million during 2003 that are included in our operating costs and expenses in the Statements of Consolidated Operations and Comprehensive Income.

During 2002, we recognized a loss of $51.3 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses. Beginning in late 2000 and extending through March 2002, a large number of our commodity hedging transactions were based on the historical relationship between natural gas and NGL prices. This type of hedging strategy utilized the forward sale of natural gas at a fixed price with the expected margin on the settlement of the position offsetting or mitigating changes in the anticipated margins on NGL marketing activities and the market values of our equity NGL production. Throughout 2001, this strategy proved very successful (as the price of natural gas declined relative to our fixed positions) and was responsible for most of the $101.3 million in commodity hedging income we recorded during 2001.

In late March 2002, the effectiveness of this strategy was reduced due to an unexpected rapid increase in natural gas prices whereby the loss in the value of our fixed-price natural gas financial instruments was not offset by increased natural gas processing margins. Due to the inherent uncertainty surrounding natural gas prices at the time, we decided that it was prudent to exit this strategy, and we did so by late April 2002. The increased ineffectiveness of this strategy is the primary reason for the $51.3 million in commodity hedging losses recorded during 2002.

Product purchase commitments. We have long and short-term purchase commitments for NGLs, petrochemicals and natural gas with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, please read "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Our Contractual Obligations*" on page 46 of this annual report.

Effect of financial instruments on Accumulated Other Comprehensive Income (Loss)

The following table summarizes the effect of our cash flow hedging financial instruments on accumulated other comprehensive income (loss) since January 1, 2002.

		Interest Rate Fin. Instrs.		Accumulated
	Commodity Financial Instruments	Treasury Locks	Forward-Starting Interest Rate Swaps	Other Comprehensive Income (Loss) Balance
Balance, January 1, 2002		$ -		$ -
Change in fair value of treasury locks		(3,560)		(3,560)
Balance, December 31, 2002		(3,560)		(3,560)
Reclassification of change in fair value of treasury locks		3,560		3,560
Gain on settlement of treasury locks		5,354		5,354
Reclassification of gain on settlement of treasury locks to interest expense		(364)		(364)
Balance, December 31, 2003		4,990		4,990
Gain on settlement of forward-starting interest rate swaps			$ 104,531	104,531
Loss on settlement of forward-starting interest rate swaps			(85,126)	(85,126)
Change in fair value of commodity financial instrument	$ 1,434			1,434
Reclassification of gain on settlement of treasury locks to interest expense		(418)		(418)
Reclassification of gain on settlement of forward-starting swaps to interest expense			(857)	(857)
Balance, December 31, 2004	$ 1,434	$ 4,572	$ 18,548	$ 24,554

During 2005, we will reclassify $0.4 million and $3.6 million from Accumulated Other Comprehensive Income as a reduction in interest expense from our treasury locks and forward-starting interest rate swaps, respectively. In addition, in the first quarter of 2005, we will record an approximate $1.6 million gain into income from Accumulated Other Comprehensive Income related to a commodity cash flow hedge acquired in the GulfTerra Merger. This gain is primarily due to an increase in fair value from that recorded for the commodity cash flow hedge at December 31, 2004.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of the CEO and CFO of Enterprise GP, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2004. Our disclosure controls and procedures are designed to provide us with a reasonable assurance that the information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO of Enterprise GP, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures 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. Based on 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 procedures are designed to provide such reasonable assurances of achieving our desired control objectives, and our CEO and CFO have concluded, as of December 31, 2004, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Internal Control over Financial Reporting

Our internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements in accordance with GAAP. These internal controls over financial reporting were designed under the supervision of our management, including the CEO and CFO of Enterprise GP, and include policies and procedures that: (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

In accordance with Item 308 of SEC Regulation S-K, management is required to provide an annual report regarding internal controls over our financial reporting. This report, which includes management's assessment of the effectiveness of our internal controls over financial reporting, is found on page 61.

Changes in internal control over financial reporting during the fourth quarter of 2004. Other than the events discussed under "Internal Controls Over Financial Reporting and the GulfTerra Merger Transactions" below, there have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) or in other factors that occurred during the fiscal quarter ended December 31, 2004, that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Internal controls over financial reporting and the GulfTerra merger and related transactions

On September 30, 2004, we completed the GulfTerra Merger and related transactions, which met the criteria of being a significant acquisition for us. For additional information regarding the GulfTerra Merger, please read "Recent Developments" under Item 1 of this annual report. At December 31, 2004, GulfTerra and the related South Texas midstream assets represented approximately 54% of our total consolidated assets. In addition, these operations accounted for 7% of our consolidated revenues for the year ended December 31, 2004.

On June 22, 2004, the Office of the Chief Accountant of the SEC issued guidance regarding the reporting of internal controls over financial reporting in connection with a major acquisition. On October 6, 2004, the SEC revised its guidance to include expectations of quarterly reporting updates of new internal controls and the status of the controls regarding any exempted businesses.

On October 18, 2004, the Disclosure Committee of Enterprise GP met and voted to recommend the exclusion of GulfTerra and the South Texas midstream assets from the scope of Enterprise's Sarbanes-Oxley Section 404 report on internal controls over financial reporting for the year ended December 31, 2004. A summary of the reasons for exclusion follow:

- Prior to completion of the GulfTerra Merger, we were required to comply with FTC guidelines regarding the sharing of information between us and GulfTerra. This severely limited our ability to conduct a timely and specific due diligence review of GulfTerra's existing internal control framework. Given the time required to test the operating effectiveness of such controls and the due date for the Section 404 attestation, it was not practical from a timing or resource standpoint for us to conduct a thorough assessment prior to year end 2004.

- GulfTerra and the South Texas midstream assets utilized a financial accounting (i.e. a general ledger) computer system that is different from that used by us. For practicality reasons, GulfTerra and the South Texas midstream assets remained on these systems (which were on a computer network owned by El Paso) through the December 31, 2004. We converted these financial accounting computer systems to ours in January 2005. As a result, we believe that reporting on the controls of the current computer system used by GulfTerra and the South Texas midstream assets during 2004 would not be useful to our investors since these systems were discontinued on December 31, 2004. In addition, we believe that obtaining an independent review of such computer systems and controls at El Paso would not have been feasible.

- Enterprise is in the process of implementing its internal control structure over the operations of GulfTerra and the South Texas midstream assets. Due to the magnitude of the businesses, we expect that this effort will be completed in late 2005. The assessment and documentation of internal controls requires a complete implementation of controls operating in a stable and effective environment.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2004

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries (the "Company"), including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to the Company's management and board of directors regarding the preparation and fair presentation of published financial statements. However, our management does not expect that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework*. This assessment included design effectiveness and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2004, the Company's internal control over financial reporting is effective based on those criteria excluding the acquired businesses from GulfTerra Energy Partners, L.P. and the South Texas midstream assets acquired from El Paso Corporation and its affiliates. Those businesses and assets were acquired on September 30, 2004 and the associated financial statements reflect total assets and revenues constituting approximately 54% and 7%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004. An explanation of this exclusion and the reasons for excluding the above mentioned acquired businesses and South Texas midstream assets are provided on page 59 of this annual report.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included on page 62 of this annual report.

Our Audit and Conflicts Committee is composed of directors who are not officers or employees of the Company. It meets regularly with members of management, the internal auditors and the representatives of the independent registered public accounting firm to discuss the adequacy of the Company's internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews with the Audit and Conflicts Committee all of the Company's significant accounting policies and assumptions affecting the results of operations. Both the independent registered public accounting firm and internal auditors have direct access to the Audit and Conflicts Committee without the presence of management.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this Annual Report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 15, 2005.

__/s/ Robert G. Phillips_______________
Name: Robert G. Phillips
Title: Principal Executive Officer of our general partner, Enterprise GP

__/s/ Michael A. Creel_______________
Name: Michael A. Creel
Title: Principal Financial Officer of our general partner, Enterprise GP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and Unitholders of
Enterprise Products Partners L.P.
Houston, Texas

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that Enterprise Products Partners L.P. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, management excluded from their assessment the internal control over financial reporting of GulfTerra Energy Partners L.P. and subsidiaries ("GulfTerra") and the South Texas midstream assets which were acquired from El Paso Corporation, (collectively referred to as the "South Texas Midstream Assets"), which were both acquired on September 30, 2004 and whose financial statements reflect total assets and revenues constituting approximately 54% and 7%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2004. Accordingly, our audit did not include the internal control over financial reporting for GulfTerra and the South Texas Midstream Assets. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM (Continued)

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets, the related statements of consolidated operations and comprehensive income, consolidated cash flows, consolidated partners' equity as of and for the year ended December 31, 2004 of the Company and our report dated March 15, 2005 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Houston, Texas
March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and Unitholders of
Enterprise Products Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of consolidated operations and comprehensive income, consolidated cash flows and consolidated partners' equity for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Houston, Texas
March 15, 2005

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2004	December 31, 2003
ASSETS		
Current Assets		
Cash and cash equivalents (includes restricted cash of $26,157 at December 31, 2004 and $13,851 at December 31, 2003)	$ 50,713	$ 44,317
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $24,310 at December 31, 2004 and $20,423 at December 31, 2003	1,058,375	462,198
Accounts receivable - related parties	25,161	347
Inventories	189,019	150,161
Assets held for sale	36,562	
Prepaid and other current assets	80,893	30,160
Total current assets	1,440,723	687,183
Property, Plant and Equipment, net	7,831,467	2,963,505
Investments in and Advances to Unconsolidated Affiliates	519,164	767,759
Intangible Assets, net of accumulated amortization of $74,183 at December 31, 2004 and $40,371 at December 31, 2003	980,601	268,893
Goodwill	459,198	82,427
Deferred Tax Asset	6,467	10,437
Long-Term Receivables	14,931	5,454
Other Assets	62,910	17,156
Total	$ 11,315,461	$ 4,802,814
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of debt	$ 15,000	$ 240,000
Accounts payable - trade	203,142	68,384
Accounts payable - related parties	41,293	38,045
Accrued gas payables	1,021,294	622,982
Accrued expenses	130,051	24,695
Accrued interest	70,335	45,350
Other current liabilities	104,764	57,420
Total current liabilities	1,585,879	1,096,876
Long-Term Debt	4,266,236	1,899,548
Other Long-Term Liabilities	63,521	14,081
Minority Interest	71,040	86,356
Commitments and Contingencies		
Partners' Equity		
Limited Partners		
Common units (364,297,340 units outstanding at December 31, 2004 and 213,366,760 units outstanding at December 31, 2003)	5,204,940	1,582,951
Restricted common units (488,525 units outstanding at December 31, 2004)	12,327	
Class B special units (4,413,549 units outstanding at December 31, 2003)		100,182
Treasury units, at cost (427,200 units outstanding at December 31, 2004 and 798,313 units outstanding at December 31, 2003)	(8,660)	(16,519)
General partner	106,475	34,349
Accumulated other comprehensive income	24,554	4,990
Deferred compensation	(10,851)	
Total Partners' Equity	5,328,785	1,705,953
Total	$ 11,315,461	$ 4,802,814

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS AND COMPREHENSIVE INCOME
(Dollars in thousands, except per unit amounts)

	For Year Ended December 31,		
	2004	2003	2002
REVENUES			
Third parties	$ 7,517,052	$ 4,782,206	$ 3,102,066
Related parties	804,150	564,225	482,717
Total	8,321,202	5,346,431	3,584,783
COST AND EXPENSES			
Operating costs and expenses			
Third parties	6,938,768	4,246,229	2,687,260
Related parties	965,568	800,548	695,579
Total operating costs and expenses	7,904,336	5,046,777	3,382,839
Selling, general and administrative costs			
Third parties	18,552	10,463	18,686
Related parties	28,107	27,127	24,204
Total selling, general and administrative costs	46,659	37,590	42,890
Total costs and expenses	7,950,995	5,084,367	3,425,729
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	52,787	(13,960)	35,253
OPERATING INCOME	422,994	248,104	194,307
OTHER INCOME (EXPENSE)			
Interest expense	(155,740)	(140,806)	(101,580)
Dividend income from unconsolidated affiliates	-	5,595	4,737
Interest income	2,083	772	2,313
Other, net	32	33	304
Other expense, net	(153,625)	(134,406)	(94,226)
INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	269,369	113,698	100,081
PROVISION FOR INCOME TAXES	(3,761)	(5,293)	(1,634)
INCOME BEFORE MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	265,608	108,405	98,447
MINORITY INTEREST	(8,128)	(3,859)	(2,947)
INCOME BEFORE CHANGES IN ACCOUNTING PRINCIPLES	257,480	104,546	95,500
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES (see Note 1)	10,781		
NET INCOME	$ 268,261	$ 104,546	$ 95,500
Cash flow financing hedges	19,405	5,354	(3,560)
Reclassification (amortization) of cash flow financing hedges	(1,275)	3,196	-
Change in fair value of commodity hedges	1,434	-	-
COMPREHENSIVE INCOME	$ 287,825	$ 113,096	$ 91,940
ALLOCATION OF NET INCOME TO:			
Limited partners' interest in net income	$ 231,153	$ 83,817	$ 84,837
General partner interest in net income	$ 37,108	$ 20,729	$ 10,663
EARNING PER UNIT: (see Note 13)			
Basic income per unit before changes in accounting principles	$ 0.83	$ 0.42	$ 0.55
Basic income per unit	$ 0.87	$ 0.42	$ 0.55
Diluted income per unit before changes in accounting principles	$ 0.83	$ 0.41	$ 0.48
Diluted income per unit	$ 0.87	$ 0.41	$ 0.48

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31,		
	2004	**2003**	**2002**
OPERATING ACTIVITIES			
Net income	$ 268,261	$ 104,546	$ 95,500
Adjustments to reconcile net income to cash flows provided by operating activities:			
Depreciation and amortization in operating costs and expenses	193,734	115,642	86,029
Depreciation and amortization in selling, general and administrative costs	1,650	159	77
Amortization in interest expense	3,503	12,634	8,819
Equity in (income) loss of unconsolidated affiliates	(52,787)	13,960	(35,253)
Distributions received from unconsolidated affiliates	68,027	31,882	57,662
Provision for impairment of long-lived asset	4,114	1,200	
Cumulative effect of changes in accounting principles	(10,781)		
Operating lease expense paid by EPCO	7,705	9,010	9,033
Other expenses paid by EPCO		436	
Minority interest	8,128	3,859	2,947
Gain on sale of assets	(15,901)	(16)	(1)
Deferred income tax expense	9,608	10,534	2,080
Changes in fair market value of financial instruments	5	(29)	10,213
Increase in restricted cash	(12,305)	(5,100)	(2,999)
Net effect of changes in operating accounts (see Note 17)	(93,725)	120,888	92,655
Cash provided by operating activities	379,236	419,605	326,762
INVESTING ACTIVITIES			
Capital expenditures	(155,793)	(146,790)	(76,160)
Contributions in aid of construction	8,865	877	4,025
Proceeds from sale of assets	6,882	212	165
Cash used for business combinations, net of cash received	(724,661)	(37,348)	(1,620,727)
Acquisition of intangible asset		(2,000)	(2,000)
Investments in and advances to unconsolidated affiliates	(64,412)	(471,927)	(13,651)
Cash used in investing activities	(929,119)	(656,976)	(1,708,348)
FINANCING ACTIVITIES			
Borrowings under debt agreements	5,934,505	1,926,210	1,968,000
Repayments of debt	(5,808,877)	(2,033,000)	(637,000)
Debt issuance costs	(19,911)	(8,833)	(19,329)
Distributions paid to partners	(438,765)	(309,918)	(214,869)
Distributions paid to minority interests	(6,440)	(8,113)	(3,324)
Contributions from minority interests	9,585	5,949	1,976
Proceeds from issuance of common units	846,077	573,684	180,666
Proceeds from issuance of Class B special units		102,041	
Treasury units reissued (purchased)	8,394	646	(12,788)
Settlement of cash flow hedging financial instruments	19,405	5,354	
Cash provided by financing activities	543,973	254,020	1,263,332
NET CHANGE IN CASH AND CASH EQUIVALENTS	(5,910)	16,649	(118,254)
CASH AND CASH EQUIVALENTS, JANUARY 1	30,466	13,817	132,071
CASH AND CASH EQUIVALENTS, DECEMBER 31	$ 24,556	$ 30,466	$ 13,817

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY

(See Note 10 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in thousands)

	Limited Partners	General Partner	Treasury units	Accum. OCI	Total
Balance, January 1, 2002	$ 1,141,613	$ 11,531	$ (6,222)		$ 1,146,922
Net income	84,837	10,663			95,500
Operating leases paid by EPCO	8,943	90			9,033
Cash distributions to partners	(203,013)	(11,856)			(214,869)
Proceeds from issuance of common units (see Note 10)	178,859	1,807			180,666
Treasury unit transactions:					
Purchased			(12,788)		(12,788)
Reissued to satisfy unit options	(1,190)	(12)	1,202		-
Change in fair value of financial instruments recorded as cash flow hedges				$ (3,560)	(3,560)
Balance, December 31, 2002	$ 1,210,049	$ 12,223	$ (17,808)	$ (3,560)	$ 1,200,904
Net income	83,817	20,729			104,546
Operating leases paid by EPCO	8,913	97			9,010
Other expenses paid by EPCO	433	3			436
Cash distributions to partners	(287,314)	(22,604)			(309,918)
Proceeds from issuance of common units (see Note 10)	567,945	5,739			573,684
Proceeds from issuance of Class B special units (see Note 10)	100,000	2,041			102,041
Restructuring of Enterprise GP ownership in our Operating Partnership (see Note 10)	(73)	16,127			16,054
Treasury unit transactions:					
Reissued to satisfy unit options	6		640		646
Retired	(643)	(6)	649		-
Treasury lock financial instruments recorded as cash flow hedges:					
Reclassification of change in fair value				3,560	3,560
Cash gains on settlement				5,354	5,354
Amortization of gain as component of interest expense				(364)	(364)
Balance, December 31, 2003	$ 1,683,133	$ 34,349	$ (16,519)	$ 4,990	$ 1,705,953

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY - (Continued)

(See Note 10 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in thousands)

	Limited Partners	General Partner	Treasury units	Deferred Comp.	Accum. OCI	Total
Balance, December 31, 2003	$ 1,683,133	$ 34,349	$ (16,519)		$ 4,990	$ 1,705,953
Net income	231,153	37,108				268,261
Operating leases paid by EPCO	7,551	154				7,705
Cash distributions to partners	(398,247)	(40,518)				(438,765)
Proceeds from issuance of common units (see Note 10)	789,758	16,117				805,875
Proceeds from conversion of Series F2 convertible units to common units (see Note 10)	38,800	792				39,592
Proceeds from exercise of unit options	398	8				406
Value of equity interests granted to complete The GulfTerra Merger (see Note 10)	2,854,275	58,252		$ (1,755)		2,910,772
Other issuance of restricted units	9,922	202		(9,922)		202
Amortization of deferred compensation				826		826
Treasury units reissued to satisfy unit options	524	11	7,859			8,394
Change in fair value of commodity hedges					1,434	1,434
Interest rate hedging financial instruments recorded as cash flow hedges:						
Cash gains on settlement					19,405	19,405
Amortization of gain as component of interest expense					(1,275)	(1,275)
Balance, December 31, 2004	$ 5,217,267	$ 106,475	$ (8,660)	$ (10,851)	$ 24,554	$ 5,328,785

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ENTERPRISE PRODUCTS PARTNERS L.P. is a publicly traded Delaware limited partnership listed on the NYSE symbol "EPD". Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Enterprise" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. Certain abbreviated names and other capitalized and industry terms are defined within the glossary of this annual report on Form 10-K.

We were formed in April 1998 to own and operate certain NGL related businesses of EPCO, Inc. ("EPCO," formerly Enterprise Products Company). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our "Operating Partnership"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as "Enterprise GP"). We and Enterprise GP are affiliates of EPCO.

On September 30, 2004, we completed the GulfTerra Merger. For additional information regarding this event, please see Note 4.

Certain reclassifications related to restricted cash have been made to the prior years' statements of cash flows to conform to the current year presentation. As a result of the GulfTerra Merger, we have reorganized our business activities into four reportable business segments, as discussed in Note 19.

In May 2002, we completed a two-for-one split of each class of our partnership units. All references to number of units or earnings per unit contained in this document reflect the unit split, unless otherwise indicated.

The consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after elimination of all material intercompany accounts and transactions. The majority-owned subsidiaries are identified based upon the determination that Enterprise possesses a controlling financial interest through direct or indirect ownership of a majority voting interest in the subsidiary. Investments in which we own 20% to 50% and exercise significant influence over operating and financial policies are accounted for using the equity method. Investments in which we own less than 20% are accounted for using the cost method unless we exercise significant influence over operating and financial policies of the investee, in which case the investment is accounted for using the equity method. As a result of recently issued accounting guidance under EITF 03-16, the minimum ownership requirement for an investment organized as a limited liability company ("LLC") to qualify for the equity method of accounting was lowered to between 3% and 5% from the 20% threshold applied to other types of investments. On July 1, 2004, we changed our method of accounting for VESCO from the cost method to the equity method in accordance with EITF 03-16. For additional information regarding this change in accounting method, see Note 7.

We have historically included equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be suppliers of raw materials or consumers of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs and petrochemicals. Our asset system has multiple entry points. In general, hydrocarbons can enter our asset system through a number of ways, including an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an NGL gathering pipeline, an NGL fractionator, an NGL storage facility, an NGL transportation or distribution pipeline or an onshore natural gas pipeline. At each link along this asset system, we earn revenues based on volume or an ownership of products such as NGLs.

Many of our equity investees are present within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines through our investments in Poseidon, Cameron Highway, Deepwater Gateway, Neptune and Nemo. We also have a number of investments in NGL transportation or distribution pipelines such as those owned by Belle Rose and Dixie (prior to our purchasing consolidating interests in Dixie in January and February 2005). Other examples include our use of the Promix NGL fractionator to process NGLs extracted by our gas plants. The NGLs received from Promix then can be sold in our NGL marketing activities. Given the integral nature of our equity investees to our operations, we believe treatment of earnings from our equity method investees as a component of gross operating margin and operating income is appropriate. For additional information regarding our investments in and advances to unconsolidated affiliates, please see Note 7. For additional information regarding our business segments, please see Note 19.

ASSET RETIREMENT OBLIGATIONS are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development, and/or normal operation. In determining asset retirement obligations, we must identify those legal obligations that we are required to settle as result of existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.

SFAS No. 143, "*Accounting for Asset Retirement Obligations*," addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and related asset retirement costs. It requires us to record the fair value of an asset retirement obligation (a liability) in the period in which it is incurred. When a liability is recorded, we will capitalize the cost of the liability by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, we will either settle the obligation for its recorded amount or incur a gain or loss upon settlement. We adopted SFAS No. 143 as of January 1, 2003. See Note 6 for information relating to our asset retirement obligations.

CASH FLOWS are computed using the indirect method. For cash flow purposes, we consider all highly liquid investments with an original maturity of less than three months at the date of purchase to be cash equivalents.

CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES represents the combined impact of (1) changing the method our BEF subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method and (2) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

Our BEF subsidiary owns an octane additive production facility that undergoes periodic planned outages of 30 to 45 days for major maintenance work. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services, and other related items. BEF used the accrue-in-advance method to record cost estimates for such activities; whereas, the Company's other operations used the expense-as-incurred method for their planned major maintenance activities. Our BEF subsidiary changed its accounting method on January 1, 2004 to conform to the Company's accounting for planned major maintenance costs, which better reflects expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

EITF 03-16, "*Accounting for Investments in Limited Liability Companies*," requires investments in limited liability companies that have separate ownership accounts for each investor be accounted for similar to limited partnerships under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), investors are required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3-5%) than the traditional 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Prior to July 1, 2004, we accounted for our 13.1% investment in VESCO using the cost method. As a result, we recognized dividend income from VESCO to the extent that we received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we recorded a cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in periods prior to July 1, 2004 and (ii) the dividend income from VESCO we recorded using the cost method in prior periods. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

For the periods indicated, the following table shows pro forma net income and earnings per unit amounts assuming the accounting changes noted above were applied retroactively to January 1, 2002. See Note 13 for information regarding the effect of the accounting changes on basic and diluted earnings per unit.

	For the Year Ended December 31,		
	2004	2003	2002
Pro Forma income statement amounts:			
Historical net income	$ 268,261	$ 104,546	$ 95,500
Adjustments to derive pro forma net income:			
Effect of change from the accrue-in-advance method to the expense-as-incurred method for BEF major maintenance costs:			
Remove historical equity in income (losses) recorded for BEF		31,508	(8,569)
Record equity in (income) losses from BEF calculated using new method of accounting for major maintenance costs		(31,800)	8,980
Remove cumulative effect of change in accounting principle recorded on January 1, 2004	(7,013)		
Remove minority interest expense associated with change in accounting principle - Sun 33.33% portion	2,338		
Effect of changing from the cost method to the equity method with respect to our investment in VESCO:			
Remove cumulative effect of change in accounting principle recorded on July 1, 2004	(3,768)		
Remove historical dividend income recorded from VESCO	(2,136)	(5,595)	(4,737)
Record equity earnings from VESCO	2,429	5,133	12,303
Pro forma net income	260,111	103,792	103,477
Enterprise GP interest	(36,945)	(20,708)	(10,743)
Pro forma net income available to limited partners	$ 223,166	$ 83,084	$ 92,734
Pro forma per unit data (basic):			
Historical units outstanding	265,511	199,915	155,454
Per unit data:			
As reported	$ 0.87	$ 0.42	$ 0.55
Pro forma	$ 0.84	$ 0.42	$ 0.60
Pro forma per unit data (diluted):			
Historical units outstanding	266,045	206,367	176,490
Per unit data:			
As reported	$ 0.87	$ 0.41	$ 0.48
Pro forma	$ 0.84	$ 0.40	$ 0.53

DOLLAR AMOUNTS (except per unit amounts) presented in the tabulations within the notes to our financial statements are stated in thousands of dollars, unless otherwise indicated.

EARNINGS PER UNIT is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Notes 10 and 13 for additional information on the capital structure and earnings per unit computation.

ENVIRONMENTAL COSTS for remediation are accrued based on the estimates of known remediation requirements. Such accruals are based on management's estimate of the ultimate costs to remediate the site. Ongoing environmental compliance costs are charged to expense as incurred, and expenditures to mitigate or prevent future environmental contamination are capitalized. Environmental costs and related accruals were not significant prior to the GulfTerra Merger. As a result of the GulfTerra Merger, we have initially estimated an environmental liability of $21 million, which is included in other long-term liabilities on our Consolidated Balance Sheet at December 31, 2004, for remediation costs expected to be incurred over time associated with mercury gas meters. Costs of environmental compliance and monitoring aggregated $1.9 million, $1.6 million and $1.7 million for the years ended December 31, 2004, 2003 and 2002, respectively.

EXCESS COST OVER UNDERLYING EQUITY IN NET ASSETS (or "excess cost") denotes the excess of our cost (or purchase price) over our underlying equity in the net assets of our investees. At December 31, 2004, our investments in Promix, La Porte, Dixie, Neptune, Poseidon, Cameron Highway and Nemo included excess cost. The excess cost of these investments is reflected in our investments in and advances to unconsolidated affiliates for these entities.

We evaluate equity method investments (which include excess cost amounts attributable to tangible or intangible assets) for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the investee or long-term negative changes in the investee's industry. In the event that we determine that the loss in value of an investment is other than a temporary decline, we would record a charge to earnings to adjust the carrying value to fair value. See Note 7 for a further discussion of the excess cost related to these investments.

EXCHANGES are contractual agreements for movements of NGL and petrochemical products between parties to satisfy timing and logistical needs of the parties. Net exchange volumes borrowed from us under such agreements are valued and included in accounts receivable, and net exchange volumes loaned to us under such agreements are valued and accrued as a liability in accrued gas payables.

EXIT AND DISPOSAL COSTS are those charges associated with an exit activity that does not involve an entity newly acquired in a business combination or with a disposal activity covered by SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*." Examples of these costs include (i) termination benefits provided to current employees that are involuntarily terminated under the terms of a benefit arrangement that, in substance, is not an ongoing benefit arrangement or an individual deferred compensation contract, (ii) costs to terminate a contract that is not a capital lease, and (iii) costs to consolidate facilities or relocate employees. In accordance with SFAS No. 146, "*Accounting for Costs Associated with Exit and Disposal Activities*," we recognize such costs when they are incurred rather than at the date of our commitment to an exit or disposal plan. We adopted SFAS No. 146 on January 1, 2003. Our adoption of this standard has had no material impact on our financial statements.

FINANCIAL INSTRUMENTS such as swaps, forward and other contracts to manage the price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions are used by Enterprise. We recognize our transactions on the balance sheet as assets and liabilities based on the instrument's fair value. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. Changes in fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset related results of the hedge item in the income statement for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses on a cash flow hedge are reclassified into earnings when the forecasted transaction occurs. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify as a hedge, the item to be hedged must expose us to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness is recorded into earnings immediately. See Note 18 for a further discussion of our financial instruments.

GOODWILL represents the excess of amounts we paid for businesses and assets over the respective fair value of the underlying net assets purchased (see Note 8). Since adopting SFAS No. 142, "*Goodwill and Other Intangible Assets*", on January 1, 2002, our goodwill amounts are no longer amortized but are assessed annually for recoverability. In addition, we periodically review the reporting units to which the goodwill amounts relate if impairment indicators are evident. If such indicators are present (i.e., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit, including its related goodwill, will be calculated and compared to its combined book value. If the fair value of the reporting unit exceeds its book value, goodwill is not considered impaired and no adjustment to earnings would be required. Should the fair value of the reporting unit (including its goodwill) be less than its book value, a charge to earnings would be recorded to adjust goodwill to its implied fair value. We have not recognized any impairment losses related to our goodwill for any of the periods presented.

INTANGIBLE ASSETS consist primarily of the estimated value assigned to certain customer relationships and certain customer contracts (see Note 8). Our customer relationship intangible assets represent the customer base that GulfTerra and the South Texas midstream assets serve through providing services, including natural gas gathering and processing, NGL fractionation and pipeline transportation. These entities conduct the majority of their business through regular contact and the use of written contracts. The value of these customer relationships are being amortized using expected production curves associated with the underlying resource bases (i.e., the oil and gas reserves associated with the intangible assets). Our estimate of the economic life of each resource base is based on a number of factors, including third-party reserve estimates, the economic viability of production and exploration activities and other industry factors.

Our contract-based intangible assets represent the rights we own arising from contractual agreements primarily within our natural gas and NGL operations. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life based on the respective contract terms. Our estimate of useful life is also based on a number of factors, including the expected useful life of related assets (i.e., fractionation facility, pipeline, etc.) and the effects of obsolescence, demand, competition and other factors.

INVENTORIES primarily consist of NGL, petrochemical and natural gas volumes and are valued at the lower of average cost or market (see Note 5). Shipping and handling charges directly related to volumes we purchase or to which we take ownership are capitalized as costs of inventory. As these inventories are sold and delivered out of inventory, the average cost of these products (which includes freight-in charges which have been capitalized) are charged to current period operating costs and expenses. Shipping and handling charges for products we sell and deliver to customers are charged to operating costs and expenses as incurred.

Costs and expenses, as shown on our Statements of Consolidated Operations and Comprehensive Income, include costs of sales related to inventories. For the years ended December 31, 2004, 2003 and 2002, such consolidated cost of sales amounts were $7.2 billion, $4.5 billion and $3 billion, respectively.

LONG-LIVED ASSETS (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable.

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value in accordance with SFAS No. 144 "*Accounting for the Impairment or Disposal of Long-Lived Assets*." Under SFAS No. 144, an asset shall be tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows.

In order to complete the GulfTerra Merger, the FTC required us to sell our interest in a Mississippi propane storage facility in which we owned a 50% interest. As a result of our determination of this long-lived asset's current market value, we recorded a $4 million non-cash asset impairment charge during the third quarter of 2004, which is reflected a component of operating costs and expenses on our 2004 Statement of Consolidated Operations.

Additionally, during 2003 we recorded a $1.2 million asset impairment charge related to our Petal NGL fractionator. This non-cash amount is a component of operating costs and expenses as shown on our 2003 Statement of Consolidated Operations. The Petal NGL fractionation facility was decommissioned in December 2003 after management decided that this older facility did not fit into our long-range plans due to poor economics of continued operations at the site. We continue to own this facility, the carrying value of which has been adjusted to its fair value of approximately $0.1 million. We did not recognize any impairment losses during 2002.

NATURAL GAS IMBALANCES result when a customer delivers more or less gas into our pipelines than they take out. We generally value our imbalances using a twelve-month moving average of natural gas prices, which we believe is an appropriate assumption to estimate the value of the imbalances upon settlement given that the actual settlement dates may vary by customer. Changes in natural gas prices may impact our estimates. Prior to the GulfTerra Merger, natural gas imbalances were not significant.

At December 31, 2004, our imbalance receivables were $56.7 million and are reflected as a component of accounts receivable. At December 31, 2004, our imbalance payables were $59 million and are reflected as a component of accrued gas payables.

PROPERTY, PLANT AND EQUIPMENT is recorded at its original cost of construction or, upon acquisition, the fair value of the asset acquired. Our property, plant and equipment is generally depreciated using the straight-line method over the asset's estimated useful life. Maintenance, repairs and minor renewals are charged to operations as incurred. The cost of assets retired or sold, together with the related accumulated depreciation, is removed from the accounts. Any gain or loss on disposition is included in operating income.

Additions and improvements to and major renewals of existing assets are capitalized and depreciated using the straight-line method over the estimated useful life of the new equipment or modifications. These expenditures result in a long-term benefit to Enterprise. See Note 6 for additional information regarding our property, plant and equipment.

We use the expense-as-incurred method for our planned major maintenance activities. Prior to January 1, 2004, BEF, which became a majority owned consolidated subsidiary on September 30, 2003, used the accrue-in-advance method for its planned major maintenance costs. On January 1, 2004, BEF elected to change its method of accounting for these costs to the expense-as-incurred method. As a result, our consolidated statement of operations for 2004 reflect the cumulative effect of change in accounting method associated with the removal of BEF's $7.0 million liability for accrued costs for planned future major maintenance activities.

PROVISION FOR INCOME TAXES is primarily applicable to certain federal and/or state tax obligations of our Mid-America and Seminole pipelines. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. See Note 12 for additional information regarding our provision of income taxes.

Our limited partnership structure is not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

RESTRICTED CASH includes amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for physical purchase transactions made on the NYMEX exchange. At December 31, 2004 and 2003, cash and cash equivalents includes, $26.2 million and $13.9 million of restricted cash related to these requirements, respectively.

REVENUE is recognized using the following criteria: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. See Note 3 for additional information regarding our revenue recognition process.

When the contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), a determination of the necessity of an allowance is made and recorded accordingly. Our allowance for doubtful accounts amount is generally determined as a percentage of revenues for the last twelve months. Our procedure for recording an allowance for doubtful accounts is based on historical experience, financial stability of our customers and levels of credit granted to customers. In addition, we may also increase the allowance account in response to specific identification of customers involved in bankruptcy proceedings and those experiencing financial uncertainties. We routinely review our estimates in this area to ascertain that we have recorded sufficient reserves to cover forecasted losses. Our allowance for doubtful accounts was $24.3 million and $20.4 million at December 31, 2004 and 2003, respectively.

A substantial portion of our revenues are derived from various companies in the domestic natural gas, NGL and petrochemical industry. This concentration could affect our overall exposure to credit risk since these customers might be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults.

UNIT OPTION PLAN ACCOUNTING is based on the intrinsic-value method described in APB No. 25, "*Accounting for Stock Issued to Employees.*" Under this method, no compensation expense is recorded related to options granted when the exercise price is equal to or greater than the market price of the underlying equity on the date of grant. In accordance with SFAS No. 148, "*Accounting for Stock-Based Compensation – Transition and Disclosure,*" we disclose the pro forma effect on our earnings as if the fair-value method of SFAS No. 123, "Accounting for Stock-Based Compensation" had been used instead of the intrinsic-value of APB No. 25. The effects of applying SFAS No. 123 in the following pro forma disclosure may not be indicative of future amounts as additional awards in future years are anticipated. The following table shows the pro forma effects for the periods indicated.

	For Year Ended December 31,		
	2004	**2003**	**2002**
Historical net income	$ 268,261	$ 104,546	$ 95,500
Additional unit option-based compensation expense estimated using fair value-based method	(932)	(1,107)	(2,077)
Pro forma net income	267,329	103,439	93,423
Less incentive earnings allocations to Enterprise GP	(32,391)	(19,699)	(9,806)
Pro forma net income after incentive earnings allocation	234,938	83,740	83,617
Multiplied by Enterprise GP ownership interest	2.0%	1.2%	1.0%
Standard earnings allocation to Enterprise GP	$ 4,699	$ 1,005	$ 836
Incentive earnings allocation to Enterprise GP	$ 32,391	$ 19,699	$ 9 ,806
Standard earnings allocation to Enterprise GP	4,699	1,005	836
Enterprise GP interest in pro forma net income	$ 37,090	$ 20,704	$ 10,642
Pro forma net income	$ 267,329	$ 103,439	$ 93,423
Less Enterprise GP interest in pro forma net income	(37,090)	(20,704)	(10,642)
Pro forma net income available to limited partners	$ 230,239	$ 82,735	$ 82,781
Basic earnings per unit, net of Enterprise GP interest:			
Historical units outstanding	265,511	199,915	155,454
As reported	$ 0.87	$ 0.42	$ 0.55
Pro forma	$ 0.87	$ 0.41	$ 0.53
Diluted earnings per unit, net of Enterprise GP interest:			
Historical units outstanding	266,045	206,367	176,490
As reported	$ 0.87	$ 0.41	$ 0.48
Pro forma	$ 0.87	$ 0.40	$ 0.47

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

	2004	2003	2002
Expected life of options	7 years	7 years	7 years
Risk-free interest rate	3.99%	3.79%	3.10%
Expected dividend yield	8.78%	9.12%	5.65%
Expected Unit price volatility	29%	29%	25%

USE OF ESTIMATES AND ASSUMPTIONS by management that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period are required for the preparation of financial statements in conformity with accounting principles generally accepted in the United States of America. Our actual results could differ from these estimates.

2. RECENT ACCOUNTING DEVELOPMENTS

FIN 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements. Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-06, "*Participating Securities and the Two-Class Method under SFAS No. 128*." This accounting guidance, which is applicable for the period beginning April 1, 2004, requires the two-class method for calculating earnings per share for certain securities that are considered to participate in earnings with common shareholders. Under the two-class method, distributions to equity owners are subtracted from earnings, and any remaining earnings would be allocated to the various classes of owners in proportion to their right to receive distributions as if those earnings had been distributed. The total distributions to each class of owner plus the amount allocated to each class would be used to compute earnings per unit for that class. Since our distributions to owners exceeded earnings during the periods presented, as has historically been the case, the two-class method did not produce any change from the way we have traditionally computed earnings per unit. As a result, our adoption of this standard had no effect on our earnings per unit calculations.

SFAS No. 151, "Inventory Costs — an Amendment of ARB No. 43, Chapter 4." This accounting guidance, which is applicable for fiscal years beginning after June 15, 2005, amends ARB No. 43, Chapter 4, to clarify that abnormal amounts of idle facility expense, freight, handling costs and wasted materials (spoilage) should be recognized as current period charges. It also requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. We do not expect the adoption of SFAS No. 151 to have a material impact on our financial position, results of operations or cash flows.

SFAS No. 123(R), "Share-Based Payment." This accounting guidance, which is applicable for the first interim or annual reporting period beginning after June 15, 2005, replaces SFAS No. 123, "*Accounting for Stock-Based Compensation*" and supersedes APB No. 25, "*Accounting for Stock Issued to Employees*." This Statement eliminates the ability to account for share-based compensation transactions using APB No. 25, and generally requires instead that such transactions be accounted for using a fair-value-based method.

This statement requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award - the requisite service period (usually the vesting period). No compensation cost is recognized for equity instruments for which employees do not render the requisite service. Employee share purchase plans will not result in recognition of compensation cost if certain conditions are met; those conditions are much the same as the related conditions in SFAS No. 123.

A public entity will initially measure the cost of employee services received in exchange for an award of liability instruments based on its current fair value; the fair value of that award will be remeasured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period.

The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments (unless observable market prices for the same or similar instruments are available). If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification.

We are continuing to evaluate the provisions of SFAS No. 123(R) and will fully adopt the standard during 2005 within the prescribed time periods. Upon the required effective date, we will apply this statement using a modified version of prospective application as described in the standard.

3. REVENUE RECOGNITION

The following summarizes our consolidated revenue recognition policies by business segment, which are generally organized according to the type of services rendered and products produced and/or sold:

Offshore Pipelines & Services. Revenues from our offshore natural gas pipelines are derived from fee-based contracts and are typically based on transportation fees per unit of volume (typically in MMBtus) transported multiplied by the volume delivered. Revenues are recognized when volumes have been physically delivered for the customer through the pipeline.

Revenues from the majority of our offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points on our crude oil pipelines for an index-based price, less a price differential, and sell the oil back to the shippers at various redelivery points at the index-based price. The net revenue from these arrangements are based on the price differential (difference between the purchase and sales price) per unit of volume (typically in barrels) multiplied by the volume delivered. Revenues associated with these purchase and sale arrangements are recorded as net revenue and are recognized when we complete the delivery of crude oil to the purchaser. Revenues from some of our offshore crude oil pipelines are based upon a gathering fee per unit of volume (typically in barrels) multiplied by the volume delivered. Revenues from the gathering fees we charge for our services are dependent on the volume of crude oil to be delivered and the amount and term of the reserve commitment by the customer.

Under our platform services contracts, there are typically two components of revenues, a demand fee which is typically a fixed-fee charged to a customer using our platform services regardless of the volume the customer delivers to the platform, and a commodity charge which is typically a fixed-fee per MMcf of natural gas or barrel of crude oil, whichever the case may be, multiplied by the volume delivered to our platform by the customer. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractual fixed period of time. Revenues for platform services, including both demand fees and commodity charges, are recognized in the period the services are provided.

Onshore Natural Gas Pipelines & Services. Revenues from some of our onshore natural gas pipelines are derived from fee-based contracts and are typically based upon a transportation fee per unit of volume (generally in MMBtus) transported multiplied by the volume delivered. The transportation fee is generally contractual or as regulated by various governmental agencies, including the FERC. Revenues associated with these fee-based contracts are recognized when volumes have been physically delivered to our customer through the pipeline. Additionally, we have natural gas sales contracts associated with some of our onshore natural gas pipelines whereby revenue is recognized when we sell and deliver a volume of natural gas to a customer. Revenues from these natural gas sales contracts are based upon market-related prices as determined by the individual agreements.

Under our natural gas storage contracts, there are typically two components of revenues, fixed monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage of the storage facilities, and storage fees per unit of volume stored at the facilities. Revenues from demand payments are recognized throughout the period in which the capacity is reserved by the customer, and revenues from storage fees associated with volumes stored at our facilities are recognized in the period the services are provided.

NGL Pipelines & Services. In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, fee-based contracts, hybrid contracts (mixed percent-of-liquids and fee-based) and keepwhole contracts. The most significant contract affecting our natural gas processing business is the Shell agreement, which is a margin-band arrangement, which grants us the right to process Shell's current and future production within state and federal waters of the Gulf of Mexico. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer.

Our NGL marketing activities within this segment use product sales contracts with various customers to sell and deliver NGLs as a result of our margin-band, keepwhole and percent-of-liquids arrangements and those it purchases from third parties in the open market. These NGL sales contracts may include forward product sales contracts from time-to-time. Revenues from NGL sales contracts are recognized and recorded upon the delivery of the NGL products to our customers. Pricing for these sales contracts is based upon market-related prices and can include pricing differentials due to factors such as differing delivery locations.

Under our NGL transportation contracts, revenue is recognized when volumes have been physically delivered to our customer through the pipeline. Revenue from these contracts is generally based upon a fixed fee per gallon of liquids transported, multiplied by the volume delivered. The fixed fee is generally contractual or as required by various governmental agencies, including the FERC.

Under our NGL and related product storage contracts, we collect a fee based on the number of days a customer has NGL or petrochemical volumes in storage multiplied by a storage rate for each product. Under these contracts, revenue is recognized ratably over the length of the storage period based on the storage fees specified in each contract.

Revenues from product terminaling contracts (applicable to our import and export operations) are recorded when services have been performed. In our export operations, we record revenues related to demand fees collected from exporters and shippers in the event they contract for use of our facilities and later fail to do so. The demand fees are contractual and vary by agreement. We recognize revenue from contractual demand fees after the exporter or shipper fails to utilize our facilities as required by contract.

We also enter into NGL fractionation fee-based arrangements and NGL fractionation percent-of-liquids contracts. Under our fee-based arrangements, we recognize revenue upon completion of all contract services and obligations. These fee-based arrangements typically include a base-processing fee (typically in cents per gallon) subject to adjustment for changes in certain of our fractionation expenses, including natural gas fuel costs. For some of our NGL fractionation facilities, we utilize percent-of-liquids contracts. A percent-of-liquids processing contract allows us to retain a contractually determined percentage of NGL products fractionated for our customer in lieu of collecting a cash-tolling fee per gallon.

Petrochemical Services. We enter into isomerization and propylene fractionation fee-based processing arrangements and petrochemical product sales contracts. Under our processing arrangements, we recognize revenue upon completion of all contract processing services and obligations. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of fractionation and isomerization operations.

In our petrochemical product sales contracts, we recognize revenue when the products have been delivered to the customer. Pricing for sales contracts is based upon market-related prices as determined by the individual agreements.

Consolidated revenues compared to segment revenues. Segment revenues include intersegment and intrasegment revenues, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions. See Note 19 for additional information regarding intersegment and intrasegment revenues and a reconciliation of total segment revenues to total consolidated revenues.

4. BUSINESS COMBINATIONS

GulfTerra Merger

On September 30, 2004, Enterprise and GulfTerra completed the merger of GulfTerra with a wholly owned subsidiary of Enterprise. Additionally, Enterprise completed certain other transactions related to the merger, including receipt of Enterprise GP's contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise GP from El Paso, and the purchase of certain midstream energy assets located in South Texas from El Paso. The aggregate value of the total consideration Enterprise paid or issued to complete the GulfTerra Merger was approximately $4 billion.

Since the GulfTerra Merger closed on September 30, 2004, our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004, includes three months of results of operations from the GulfTerra assets. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. As a result, our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2004, includes four months of results of operations from the South Texas midstream assets.

As a result of the GulfTerra Merger, GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise on September 30, 2004. On October 1, 2004, we contributed our ownership interests in GulfTerra and GulfTerra GP to our Operating Partnership, which resulted in GulfTerra and GulfTerra GP becoming wholly owned subsidiaries of the Operating Partnership.

Formed in 1993, GulfTerra manages a balanced, diversified portfolio of interests and assets relating to the midstream energy sector, which involves gathering, transporting, separating, processing, fractionating and storing natural gas, oil and NGLs. GulfTerra's interests and assets included (i) offshore oil and natural gas pipelines, platforms, processing facilities and other energy infrastructure in the Gulf of Mexico, primarily offshore Louisiana and Texas; (ii) onshore natural gas pipelines and processing facilities in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas; (iii) onshore NGL pipelines and fractionation facilities in Texas; and (iv) onshore natural gas and NGL storage facilities in Louisiana, Mississippi and Texas.

The South Texas midstream assets consisted of nine natural gas processing plants with a combined capacity of 1.9 Bcf/d, a 294-mile natural gas gathering system, a natural gas treating facility with a capacity of 150 MMcf/d and a small NGL pipeline.

The GulfTerra Merger transactions

The GulfTerra Merger occurred in several interrelated transactions as described below.

- *Step One*. On December 15, 2003, Enterprise purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owns a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, Enterprise accounted for its investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One were borrowed under an Interim Term Loan and our pre-merger revolving credit facilities. This amount was fully repaid with the net proceeds from equity offerings completed during 2004. See Note 9 for additional information regarding changes in our debt obligations since December 31, 2003.

- *Step Two*. On September 30, 2004, the GulfTerra Merger was consummated and GulfTerra and GulfTerra GP became wholly owned subsidiaries of Enterprise. The GulfTerra Merger was accounted for using purchase accounting. Step Two of the GulfTerra Merger included the following transactions:

  - Immediately prior to closing the GulfTerra Merger, Enterprise GP acquired El Paso's remaining 50% membership interest in GulfTerra GP for $370 million in cash paid to El Paso and the issuance of a 9.9% membership interest in Enterprise GP to El Paso. Subsequently, Enterprise GP contributed this 50% membership interest in GulfTerra GP to us without the receipt of additional general partner interest, common units or other consideration. Enterprise GP borrowed the foregoing $370 million from Dan Duncan LLC (which owns a membership interest in Enterprise GP), which obtained the funds from a loan from EPCO (which indirectly owns the remaining membership interests in Enterprise GP).

  - Immediately prior to closing the GulfTerra Merger, Enterprise paid $500 million in cash to El Paso for 10,937,500 Series C units of GulfTerra and 2,876,620 common units of GulfTerra. The remaining 57,762,369 GulfTerra common units (7,433,425 of which were owned by El Paso) were converted into 104,549,823 Enterprise common units (13,454,499 of which are held by El Paso) at the time of the consummation of the GulfTerra Merger.

- *Step Three*. Immediately after Step Two was completed, Enterprise acquired certain South Texas midstream assets from El Paso for $155.3 million in cash. Pursuant to written agreements, our purchase of the South Texas midstream assets was effective September 1, 2004.

In connection with the closing of the GulfTerra Merger, on September 30, 2004, our Operating Partnership borrowed an aggregate $2.8 billion under its new revolving credit facilities in order to fund its cash payment obligations under Step Two and Step Three of the GulfTerra Merger and related transactions, including the tender offers for GulfTerra's outstanding senior and senior subordinated notes. See Note 9 for a description of these new borrowing and debt-related transactions.

The total consideration paid or granted for the GulfTerra Merger is summarized below:

Step One transaction:	
Cash payment by Enterprise to El Paso for initial 50% membership interest in GulfTerra GP (a non-voting interest) made in December 2003	$ 425,000
Total Step One consideration	425,000
Step Two transactions:	
Cash payment by Enterprise to El Paso for 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units	500,000
Fair value of equity interests granted to acquire remaining 50% membership interest in GulfTerra GP (voting interest) (1)	461,347
Fair value of Enterprise common units issued in exchange for remaining GulfTerra common units (see Note 10)	2,445,420
Fair value of other Enterprise equity interests granted for unit awards and Series F2 convertible units	4,004
Fair value of receivable from El Paso for transition support payments (2)	(40,313)
Transaction fees and other direct costs incurred by Enterprise as a result of the GulfTerra Merger (3)	24,032
Total Step Two consideration	3,394,490
Total Step One and Step Two consideration	3,819,490
Step Three transaction:	
Purchase of South Texas midstream assets from El Paso	155,277
Total consideration for Steps One through Three	$ 3,974,767

(1) This fair value is based on 50% of an implied $922.7 million total value of GulfTerra GP, which assumes that the $370 million cash payment made by Enterprise GP to El Paso represented consideration for a 40.1% interest in GulfTerra GP. The 40.1% interest was derived by deducting the 9.9% membership interest in Enterprise GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise GP received. The fair value of $461.3 million assigned to this voting membership interest in GulfTerra GP compares favorably to the $425 million paid to El Paso by Enterprise to purchase its initial 50% non-voting membership interest in GulfTerra GP in December 2003. The contribution of this 50% membership interest to Enterprise is allocated for financial reporting purposes to Enterprise's limited partners and general partner based on the respective ownership percentages and the related allocation of profits and losses of 98% and 2%, respectively, both of which are consistent with the Partnership Agreement.

(2) Reflects the present value of a contract-based receivable from El Paso received as part of the negotiated net consideration reached in Step One of the GulfTerra Merger. The agreements between Enterprise and El Paso provide that for a period of three years following the closing of the GulfTerra Merger, El Paso will make transition support payments to Enterprise in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. The $45 million receivable from El Paso has been discounted to fair value and recorded as a reduction in the purchase consideration for GulfTerra. As December 31, 2004, the fair value of the current portion and non-current portion of this contract-based receivable was $17.2 million and $23.1 million, respectively; these amounts are reflected as a component of "Prepaid and other current assets" and "Long-term receivables" on our Consolidated Balance Sheet as of December 31, 2004.

(3) As a result of the GulfTerra Merger, Enterprise incurred expenses of approximately $24 million for various transaction fees and other direct costs. These direct costs include fees for legal, accounting, printing, financial advisory and other services rendered by third-parties to Enterprise over the course of the GulfTerra Merger transactions. This amount also includes $3.4 million of involuntary severance costs.

In connection with the GulfTerra Merger, we are required under a consent decree to sell our 50% interest in Starfish, which owns the Stingray natural gas pipeline and related gathering pipelines and dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana. In January 2005, we entered into a contract with a third party to sell this investment for approximately $42.1 million. We expect to close this sale during the first quarter of 2005. The sale requires FTC approval under the terms of the consent decree relating to the GulfTerra Merger and is subject to other customary closing conditions. Additionally, under the same consent decree, we were required to sell our undivided 50% interest in a Mississippi propane storage facility by December 31, 2004. We sold our interest in this facility during the fourth quarter of 2004.

Other Business Combinations and Asset Acquisitions Completed During 2004

During 2004, we also acquired an additional 16.7% interest in Tri-States; an additional 10% interest in Seminole; the remaining 33.3% ownership interest in BEF; and certain assets located in Morgan's Point, Texas.

Acquisition of 16.7% interest in Tri-States. On April 1, 2004, we acquired an additional 16.7% membership interest in Tri-States, which owns an NGL pipeline located along the Mississippi, Alabama and Louisiana Gulf Coast. This system, in conjunction with the Wilprise and Belle Rose NGL pipelines, transport mixed NGLs to the BRF, Norco and Promix NGL fractionators located in south Louisiana. Due to this acquisition, our ownership interest in Tri-States increased to 66.7% and Tri-States became a majority-owned consolidated subsidiary of ours on April 1, 2004. Previously, Tri-States was accounted for as an equity method unconsolidated affiliate.

Acquisition of 10% interest in Seminole. On May 31, 2004, we acquired an additional 10% interest in Seminole, which owns a regulated 1,281-mile pipeline that transports mixed NGLs and NGL products from the Hobbs hub on the Texas-New Mexico border and the Permian Basin area to southeast Texas. As a result of this acquisition, our ownership interest in Seminole increased to 88.4%. The Seminole pipeline is interconnected with our Mid-America pipeline system at the Hobbs hub. The primary source of throughput for Seminole is volume originating from the Mid-America system.

Acquisition of remaining 33.3% interest in BEF. On September 1, 2004, we acquired the remaining 33.3% ownership interest in BEF, which owns a facility that produces octane additives such as MTBE (a motor gasoline additive that enhances octane and is used in reformulated gasoline). As a result of this acquisition, BEF became a wholly owned subsidiary of ours.

Acquisition of Morgan's Point assets. On December 13, 2004, we acquired certain assets located in Morgan's Point, Texas from Valero. The assets acquired primarily include an octane enhancement facility, a butane isomerization facility, a barge dock and NGL and petrochemical pipelines.

Allocation of Purchase Price of 2004 Business Combinations

The GulfTerra Merger transactions and our other business and asset acquisitions completed during 2004 were recorded using the purchase method of accounting. Purchase accounting requires us to allocate the cost of a business combination to the assets acquired and liabilities assumed based on their estimated fair values. Enterprise engaged an independent third-party business valuation expert to assess the fair values of the tangible and intangible assets of GulfTerra, the South Texas midstream assets, and those acquired in the Morgan's Point transaction. This information will assist management in the development of a definitive allocation of the overall purchase price of the GulfTerra Merger transactions. Management independently developed the fair value estimates for the other 2004 business acquisitions using recognized business valuation techniques.

The preliminary fair values shown in the following table are estimates based on information available to management at December 31, 2004. The valuation estimates shown below could change due to this recent transaction and the refinement of our estimates.

	Merger-Related Transactions			
	Step Two of GulfTerra Merger	Step Three Purchase of South Texas Midstream Assets	Other 2004 Acquisitions	Total
Purchase price allocation:				
Assets acquired in business combination:				
Current assets, including cash of $40,453	$ 198,347	$ 7,614	$ 10,374	$ 216,335
Property, plant and equipment, net	4,601,390	112,830	92,721	4,806,941
Investments in and advances to unconsolidated affiliates	202,672		(42,597)	160,075
Intangible assets	705,459	37,802	1,092	744,353
Other assets	26,881			26,881
Total assets acquired	5,734,749	158,246	61,590	5,954,585
Liabilities assumed in business combination:				
Current liabilities	(228,566)	(2,969)	(2,329)	(233,864)
Long-term debt, including current maturities	(2,015,583)			(2,015,583)
Other long-term liabilities	(47,880)			(47,880)
Minority interest			26,590	26,590
Total liabilities assumed	(2,292,029)	(2,969)	24,261	(2,270,737)
Total assets acquired less liabilities assumed	3,442,720	155,277	85,851	3,683,848
Total consideration given	3,819,490	155,277	85,851	4,060,618
Remaining Goodwill	$ 376,770	$ -	$ -	$ 376,770

As a result of the preliminary purchase price allocation for Steps Two and Three of the GulfTerra Merger, we recorded $744.4 million of amortizable intangible assets, primarily those related to customer relationships and contracts. The remaining preliminary amount represents goodwill of $376.8 million associated with our view of the future results from GulfTerra's operations, based on the strategic location of GulfTerra's assets as well as their industry relationships. For additional information regarding these intangible assets and goodwill, see Note 8. For the recent GulfTerra Merger and the related South Texas midstream assets, the allocation of the purchase price to the estimated fair values of assets and liabilities is based, in part, upon assistance from an independent third party business valuation expert. In addition, the Morgan's Point allocation (which is a component of "Other 2004 Acquisitions" as shown in the preceding table), is preliminary. Such preliminary values are subject to final valuation reports and additional information.

Pro Forma Financial Information

The following table presents selected unaudited pro forma financial information incorporating the historical (pre-merger) results of GulfTerra, the South Texas midstream assets and our other business acquisitions. Since the GulfTerra Merger closed on September 30, 2004, our Statements of Consolidated Operations and Comprehensive Income do not include any earnings from GulfTerra prior to October 1, 2004. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. As a result, our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2004 include four months of results of operations from the South Texas midstream assets. The results of operations of our other business acquisitions are also included in our Statements of Consolidated Operations from the date of acquisition.

The following pro forma information has been prepared as if the GulfTerra Merger and our other business combination transactions had been completed on January 1, 2003 as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon data currently available and includes certain estimates and assumptions made by management. As a result, this pro forma information is not necessarily indicative of our financial results had the transactions actually occurred on this date. Likewise, the following unaudited pro forma financial information is not necessarily indicative of our future financial results.

	For the Year Ended December 31,	
(Dollars in millions, except per unit amounts)	2004	2003
Pro forma earnings data:		
Revenues	$ 9,617.0	$ 7,298.1
Costs and expenses	$ 9,066.0	$ 6,857.5
Operating income	$ 579.4	$ 366.7
Income before extraordinary items	$ 315.2	$ 72.8
Net income	$ 315.2	$ 72.8
Pro forma net income	$ 315.2	$ 72.8
Less incentive earnings allocations to Enterprise GP	(44.0)	(34.9)
Pro forma net income after incentive earnings allocation	271.2	37.9
Multiplied by Enterprise GP ownership interest	2.0%	2.0%
Standard earnings allocation to Enterprise GP	$ 5.4	$ 0.8
Incentive earnings allocation to Enterprise GP	$ 44.0	$ 34.9
Standard earnings allocation to Enterprise GP	5.4	0.8
Enterprise GP interest in pro forma net income	$ 49.4	$ 35.7
Pro forma net income	$ 315.2	$ 72.8
Less Enterprise GP interest in pro forma net income	(49.4)	(35.7)
Pro forma net income available to limited partners	$ 265.8	$ 37.1
Basic earnings per unit, net of Enterprise GP interest:		
As reported basic units outstanding	265.5	199.9
Pro forma basic units outstanding	396.9	350.3
As reported basic net income per unit	$ 0.83	$ 0.42
Pro forma basic net income per unit	$ 0.67	$ 0.11
Diluted earnings per unit, net of Enterprise GP interest:		
As reported pro forma units outstanding	266.0	206.4
Pro forma diluted units outstanding	397.4	356.8
As reported diluted net income per unit	$ 0.83	$ 0.41
Pro forma diluted net income per unit	$ 0.67	$ 0.10

The pro forma net income effect for 2003 was reduced by $45 million to include the non-cash asset impairment charge recorded by BEF. For additional information regarding this charge made during 2003, see Note 7.

5. INVENTORIES

Our inventories consisted of the following at the dates indicated:

	December 31,	
	2004	2003
Working inventory	$ 171,485	$ 135,451
Forward-sales inventory	17,534	14,710
Inventory	$ 189,019	$ 150,161

A general description of our inventories is as follows:

- Our regular trade (or "working") inventory is comprised of inventories of natural gas, NGLs and petrochemical products that are available for sale or used in the provision of services. This inventory is valued at the lower of average cost or market, with "market" being determined by industry-related posted prices such as those published by OPIS and CMAI.

- The forward-sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts and is valued at the lower of average cost or market, with "market" being defined as the weighted-average sales price for NGL volumes to be delivered in future months on the forward sales contracts.

In general, our inventory values reflect amounts we have paid for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection and demurrage charges and other handling and processing costs. In those instances where we take ownership of inventory volumes through percent-of-liquids and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 3), these volumes are valued at market-related prices during the month in which they are acquired. Like the third-party purchases described above, we inventory the various ancillary costs such as freight-in and other handling and processing amounts associated with owned volumes obtained through our in-kind and similar contracts.

Due to fluctuating market conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market ("LCM") adjustments when the cost of our inventories exceed their net realizable value. These non-cash adjustments are charged to operating costs and expenses in the period they are recognized and generally affect our segment operating results in the following manner:

- NGL inventory write-downs are recorded as a cost of the Processing segment's NGL marketing activities;
- Natural gas inventory write downs are recorded as a cost of the Pipeline segment's Acadian Gas operations; and
- Petrochemical inventory write downs are recorded as a cost of the Fractionation segment's petrochemical marketing activities or as a cost of the Octane Enhancement segment's MTBE operations, as applicable.

For the years ended December 31, 2004, 2003 and 2002, we recognized LCM adjustments of approximately $9.4 million, $16.9 million and $6.3 million, respectively. The majority of these write-downs were taken against NGL inventories. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated (or in some cases, offset). See Note 18 for a description of our commodity hedging activities.

6. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation were as follows at the dates indicated:

	Estimated Useful Life in Years	At December 31, 2004	At December 31, 2003
Plants and pipelines [1]	5-35 [5]	$ 7,691,197	$ 3,214,463
Underground and other storage facilities [2]	5-35 [6]	531,394	288,199
Platforms and facilities [3]	23-31	162,645	
Transportation equipment [4]	3-10	7,240	5,676
Land		29,142	23,447
Construction in progress		230,375	74,431
Total		8,651,993	3,606,216
Less accumulated depreciation		820,526	642,711
Property, plant and equipment, net		$ 7,831,467	$ 2,963,505

(1) Plants and pipelines includes processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities includes underground product storage caverns; storage tanks; water wells; and related assets.
(3) Platforms and facilities includes offshore platforms and related facilities and other associated assets.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) In general, the estimated useful lives of major components of this category are: processing plants, 20-35 years; pipelines, 18-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings 20-35 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of major components of this category are: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

Depreciation expense for the years ended December 31, 2004, 2003 and 2002 was $161 million, $101 million and $72.5 million, respectively. The significant portion of the year-to-year increase in depreciation expense is attributable to acquisitions we completed during each period. The year-to-year increase in depreciation expense for 2004 and 2003 is primarily due to the property, plant and equipment assets we acquired in the GulfTerra Merger, which were recorded at their preliminary fair values upon completion of the GulfTerra Merger at September 30, 2004 (see Note 4).

Capitalized interest on our construction projects for the years ended December 31, 2004, 2003 and 2002 was $2.8 million, $1.6 million and $1.1 million, respectively.

Asset retirement obligations. SFAS No. 143 establishes accounting standards for the recognition and measurement of an ARO liability and the associated asset retirement cost. As a result of the GulfTerra Merger, we assumed AROs associated with the future retirement obligations for certain limited offshore assets located in the Gulf of Mexico. The aggregate $6.2 million liability associated with this ARO is a component of "Other Long-Term Liabilities" on our Consolidated Balance Sheet as of December 31, 2004.

In addition to the obligations we assumed in the GulfTerra Merger, we have also identified ARO liabilities in our other operational areas. These include ARO liabilities related to (i) right-of-way easements over property not owned by us and (ii) regulatory requirements triggered by the abandonment or retirement of certain currently operated facilities. As a result of our analysis of these identified AROs, we were not required to recognize such potential liabilities. Our rights under the easements are renewable and only require retirement action upon nonrenewal of the easement agreements. We currently expect to renew all such easement agreements and to use these properties for the foreseeable future. Should we decide not to renew these right-of-way agreements, an ARO liability would be recorded at that time. We also identified potential ARO liabilities arising from regulatory requirements related to the future abandonment or retirement of certain currently operated facilities. At present, we currently have no intention or legal obligation to abandon or retire such facilities. An ARO liability would be recorded if future abandonment or retirement of such facilities occurred.

Certain of our unconsolidated affiliates, Deepwater Gateway, Neptune, Nemo, and Starfish, had recorded ARO's at December 31, 2004 relating to regulatory requirements. These amounts are immaterial to our financial statements and had a negligible effect on our equity earnings from these investments during 2004.

7. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for using the equity method. In general, we use the equity method of accounting for an investment in which we own 20% to 50% of its outstanding ownership interests and exercise significant influence over its operating and financial policies. We do not exercise management control over our equity or cost method investees. As a result of recently issued accounting guidance under EITF 03-16 (see Note 1), the minimum ownership requirement for an investment organized as a limited liability company (or "LLC") to qualify for the equity method of accounting was lowered to between 3% and 5% from the 20% threshold applied to other types of investments.

On July 1, 2004, we changed our method of accounting for VESCO from the cost method to the equity method in accordance with EITF 03-16. Our VESCO investment consists of a 13.1% interest in a LLC that owns a natural gas processing plant, NGL fractionation facilities, storage assets and gas gathering pipelines located in south Louisiana. For additional information regarding this change in accounting method, see Note 1.

Our investments in and advances to these unconsolidated affiliates are grouped in the following table according to the business segment to which they relate. For a general discussion of our business segments, see Note 19.

	Ownership Percentage at December 31, 2004	Investments in and advances to Unconsolidated Affiliates at December 31, 2004	Investments in and advances to Unconsolidated Affiliates at December 31, 2003
Offshore Pipeline & Services:			
Poseidon [1]	36.0%	$ 63,944	
Cameron Highway [1]	50.0%	114,354	
Deepwater Gateway [1]	50.0%	56,527	
Offshore pipeline investments [2]	Various	84,638	$ 127,605
Onshore Natural Gas Pipeline & Services:			
Evangeline	49.5%	2,810	2,519
Coyote [1]	50.0%	2,441	
NGL Pipeline & Services:			
Dixie	19.9%	32,514	35,988
VESCO	13.1%	38,437	33,000
Belle Rose	41.7%	10,172	10,780
Promix	50.0%	65,748	38,903
BRF	32.3%	27,012	27,892
Tri-States [3]			44,119
Petrochemical Services:			
BRPC	30.0%	15,617	16,584
La Porte	50.0%	4,950	5,422
Other:			
GulfTerra GP [4]			424,947
Total		$ 519,164	$ 767,759

(1) Our ownership interest in these investments was acquired in connection with the GulfTerra Merger on September 30, 2004.

(2) Reflects our collective investment in Neptune, Nemo and Starfish. In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% ownership interest in Starfish. The carrying value of our investment in Starfish was reclassified from "Investments in and Advances to Unconsolidated Affiliates" to "Assets Held for Sale" on our Consolidated Balance Sheet at December 31, 2004.

(3) We acquired an additional 16.7% ownership interest in Tri-States in April 2004. As a result of this acquisition, Tri-States became a consolidated subsidiary.

(4) In connection with the GulfTerra Merger (see Note 4), GulfTerra GP became a wholly owned consolidated subsidiary on September 30, 2004. We had previously accounted for our 50% ownership interest in GulfTerra GP as an equity method investment from December 15, 2003 through September 29, 2004.

On occasion, the price we pay to acquire an investment exceeds the underlying historical net assets (i.e., the underlying equity account balances on the books of the investee) that we purchase. These excess cost amounts are a component of our investments in and advances to unconsolidated affiliates. At December 31, 2004, our investments in Promix, La Porte, Dixie, Neptune, Poseidon, Cameron Highway and Nemo included excess cost. An analysis of each of these investments at the time of purchase indicated that such excess cost amounts were attributable to either (i) an increase in the fair value of the tangible assets owned by each entity over the investee's historical carrying values or (ii) it was unattributable to other specific assets (including intangible assets) and was deemed to be goodwill. To the extent that we attribute an excess cost amount to tangible or intangible assets, we amortize these amounts as a reduction in equity earnings in a manner similar to depreciation. To the extent we attribute an excess cost amount to goodwill, we do not amortize this amount but it is subject to evaluation for impairment. At December 31, 2004, excess cost amounts included in our investments in and advances to unconsolidated affiliates totaled $83.6 million, of which $74.3 million was attributed to tangible assets and the remainder to goodwill. Amortization of our excess cost amounts attributed to tangible assets was $1.9 million, $1.6 million, and $1.6 million during 2004, 2003 and 2002, respectively.

The following table shows our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	For the Year Ended December 31,		
	2004	**2003**	**2002**
Offshore Pipeline & Services:			
Poseidon	$ 2,509		
Cameron Highway	(461)		
Deepwater Gateway	3,562		
Offshore pipeline investments [1]	3,249	$ 5,561	$ 10,534
Onshore Natural Gas Pipeline & Services:			
Coyote	541		
Evangeline	231	131	(58)
NGL Pipelines & Services:			
Dixie	1,273	1,323	1,231
VESCO	6,132	-	-
Belle Rose	(402)	(55)	203
Promix	859	2,106	3,936
BRF	2,190	832	2,427
Tri-States [2]	(154)	1,542	1,959
Wilprise [2]		276	948
EPIK [2]		1,818	4,688
Petrochemical Services:			
BRPC	1,943	1,198	997
La Porte	(710)	(698)	(559)
BEF [2]		(27,864)	8,569
OTC [2]		(77)	378
Other:			
Gulf Terra GP [3]	32,025	(53)	
Total	$ 52,787	$ (13,960)	$ 35,253

(1) Reflects combined equity earnings from Neptune, Nemo and Starfish. In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish.

(2) We acquired additional ownership interests in or control over these entities since January 1, 2003 resulting in our consolidation of each company's post-acquisition financial results with those of our own. Our consolidation of each company's post-acquisition financial results began in the following periods: EPIK, March 2003; Wilprise, October 2003; OTC, August 2003; BEF, September 2003; and Tri-States, April 2004.

(3) In connection with the GulfTerra Merger (see Note 4), GulfTerra GP became a wholly owned consolidated subsidiary on September 30, 2004. We had previously accounted for our 50% ownership interest in GulfTerra GP as an equity method investment from December 15, 2003 through September 29, 2004.

Offshore Pipelines & Services Segment

At December 31, 2004, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

- *Poseidon Oil Pipeline Company, L.L.C.* ("Poseidon") – a 36% interest in Poseidon, which owns a crude oil pipeline extending from the Gulf of Mexico to onshore Louisiana. Poseidon completed construction of its Front Runner oil pipeline in the third quarter of 2004 and received its first volumes from this new oil pipeline in January 2005. This new oil pipeline connects the Front Runner platform in the Gulf of Mexico with Poseidon's existing system.

- *Cameron Highway Oil Pipeline Company* ("Cameron Highway") – a 50% interest in Cameron Highway, which owns a recently constructed crude oil pipeline system that connects various designated crude oil receipt points extending from Ship Shoal Block 332 in the Gulf of Mexico to onshore delivery points located in the state of Texas. We anticipate that operations will commence on this pipeline system in early 2005.

- *Deepwater Gateway, L.L.C.* ("Deepwater Gateway") – a 50% interest in Deepwater Gateway, which owns the Marco Polo tension-leg platform. The Marco Polo tension-leg platform is operated by Anadarko Petroleum Corporation ("Anadarko") and processes oil and natural gas from Anadarko's Marco Polo Field discovery located at Green Canyon Block 608 in the Gulf of Mexico. The Marco Polo tension-leg platform went into service during the third quarter of 2004.

- *Offshore pipeline investments* - our collective investment in Neptune Pipeline Company, L.L.C. ("Neptune"), Nemo Gathering Company, LLC ("Nemo") and Starfish Pipeline Company, LLC ("Starfish"). We own a 25.7% interest in Neptune, which owns the Manta Ray and Nautilus natural gas pipeline systems located in the Gulf of Mexico offshore Louisiana. In addition, we own a 33.9% interest in Nemo, which owns the Nemo natural gas pipeline located in the Gulf of Mexico offshore Louisiana. This category also includes our 50% interest in Starfish, which owns the Stingray and Triton natural gas pipeline and related dehydration and other facilities located in south Louisiana and the Gulf of Mexico. In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish. We are required to sell this investment by March 31, 2005. In January 2005, we entered into a contract with a third party to sell this investment for approximately $42.1 million. We expect this sale to close during the first quarter of 2005. The sale requires FTC approval under the terms of the consent decree and is subject to other customary closing conditions.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's unconsolidated affiliates are summarized below.

	At December 31,	
	2004	2003
BALANCE SHEET DATA:		
Current assets	$79,196	$93,277
Property, plant and equipment, net	712,182	711,853
Other assets	528,443	277,205
Total assets	$1,319,821	$1,082,335
Current liabilities	$71,758	$64,585
Other liabilities	526,990	404,170
Combined equity	721,073	613,580
Total liabilities and combined equity	$1,319,821	$1,082,335

	For Year Ended December 31,		
	2004	2003	2002
INCOME STATEMENT DATA:			
Revenues	$88,603	$76,168	$90,924
Operating income	46,938	39,658	54,752
Net income	38,473	33,700	73,509

Onshore Natural Gas Pipelines & Services Segment

At December 31, 2004, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

- *Evangeline Gas Pipeline Company, L.P.* and *Evangeline Gas Corp.* (collectively, "Evangeline") – an approximate 49.5% aggregate interest in a natural gas pipeline system located in south Louisiana.

- *Coyote Gas Treating, LLC* ("Coyote") – a 50% interest in Coyote, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's unconsolidated affiliates are summarized below.

	At December 31,	
	2004	2003
BALANCE SHEET DATA:		
Current assets	$21,652	$14,120
Property, plant and equipment, net	38,821	40,994
Other assets	35,149	38,865
Total assets	$95,622	$93,979
Current liabilities	$24,365	$16,782
Other liabilities	37,210	41,906
Combined equity	34,047	35,291
Total liabilities and combined equity	$95,622	$93,979

	For Year Ended December 31,		
	2004	2003	2002
INCOME STATEMENT DATA:			
Revenues	$257,539	$230,429	$145,289
Operating income	8,552	9,275	4,394
Net income	4,657	5,037	251

NGL Pipelines & Services Segment

At December 31, 2004, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

- *Dixie Pipeline Company* ("Dixie") – an aggregate 19.9% interest in a 1,301-mile propane pipeline and associated facilities extending from Mont Belvieu, Texas to North Carolina.

- *Venice Energy Services Company, LLC* ("VESCO") – a 13.1% interest in a natural gas processing plant, fractionation facilities, storage, and gas gathering pipelines located in southern Louisiana and, with respect to certain of the gas gathering pipelines, also in the Gulf of Mexico. On July 1, 2004, we changed our method of accounting for VESCO from the cost method to the equity method in accordance with EITF 03-16 (see Note 1).

- *Belle Rose NGL Pipeline LLC* ("Belle Rose") – a 41.7% interest in an NGL pipeline system located in south Louisiana.

- *K/D/S Promix LLC* ("Promix") – a 50% interest in an NGL fractionator and related storage and pipeline assets located in south Louisiana. In December 2004, we acquired an additional 16.7% ownership interest in Promix from Koch. As a result of this purchase, our ownership interest in Promix increased to 50%.

- *Baton Rouge Fractionators LLC* ("BRF") – an approximate 32.3% interest in an NGL fractionator located in southeastern Louisiana.

In March 2003, we purchased the remaining ownership interests in EPIK Terminalling L.P. and EPIK Gas Liquids, LLC (collectively, "EPIK"), at which time EPIK became a consolidated subsidiary of ours. In October 2003, we purchased an additional 37.4% interest in Wilprise Pipeline Company, LLC ("Wilprise"), at which time it became a 74.7% owned consolidated subsidiary of ours. In April 2004, we purchased an additional 16.7% interest in Tri-States NGL Pipeline LLC ("Tri-States"), at which time it became a 66.7% owned consolidated subsidiary of ours. See Note 4 for additional information regarding our business combinations.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's unconsolidated affiliates are summarized below.

	At December 31,	
	2004	**2003**
BALANCE SHEET DATA:		
Current assets	$101,660	$59,206
Property, plant and equipment, net	399,580	433,841
Other assets	16,993	4,304
Total assets	$518,233	$497,351
Current liabilities	$95,537	$54,195
Other liabilities	13,422	107,938
Combined equity	409,274	335,218
Total liabilities and combined equity	$518,233	$497,351

	For Year Ended December 31,		
	2004	**2003**	**2002**
INCOME STATEMENT DATA:			
Revenues	$298,061	$314,837	$287,236
Operating income	57,134	51,844	53,477
Net income	50,523	45,129	47,279

Petrochemical Services Segment

At December 31, 2004, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

- *Baton Rouge Propylene Concentrator, LLC* ("BRPC") – a 30% interest in a propylene fractionator located in southeastern Louisiana.

- *La Porte Pipeline Company, L.P.* and *La Porte Pipeline GP, LLC* (collectively "La Porte") – an aggregate 50% interest in a polymer grade propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

In November 2003, we purchased the remaining 50% of outstanding common stock of Olefins Terminal Corporation ("OTC"). As a result, OTC became a wholly owned subsidiary of ours. See Note 4 for additional information regarding our business combinations.

In September 2003, we acquired an additional 33.3% interest in *Belvieu Environmental Fuels* ("BEF"), which owns a facility that historically produced MTBE, a motor gasoline additive that enhanced octane values and is used in reformulated motor gasoline. As a result of this acquisition, BEF became a majority-owned consolidated subsidiary of ours on September 30, 2003. Previously, BEF was accounted for as an equity-method unconsolidated affiliate. In September 2004, we acquired the remaining 33.3% interest in BEF.

As a result of declining domestic demand and a prolonged period of weak MTBE production economics, several of BEF's competitors announced their withdrawal from the marketplace during 2003. Due to the deteriorating business environment and outlook and the completion of its preliminary engineering studies regarding conversion alternatives, BEF evaluated the carrying value of its long-lived assets for impairment during the third quarter of 2003. This review indicated that the carrying value of its long-lived assets exceeded their collective fair value, which resulted in a non-cash asset impairment charge of $67.5 million. Our share of this loss was $22.5 million and is recorded as a component of "Equity in loss of unconsolidated affiliates" in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2003.

BEF's assets were written down to fair value, which was determined by independent appraisers using present value techniques. The impaired assets principally represent the plant facility and other assets associated with MTBE production. The fair value analysis incorporates probability-weighted cash flows for future courses of action being taken (or contemplated to be taken) by BEF management, including modification of the facility to produce iso-octane and alkylate. If the underlying assumptions in the fair value analysis change resulting in the present value of expected future cash flows being less than the new carrying value of the facility, additional impairment charges may result in the future. See Note 16 for additional information regarding risks associated with our investment in BEF.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's unconsolidated affiliates are summarized below.

	At December 31,	
	2004	**2003**
BALANCE SHEET DATA:		
Current assets	$ 3,266	$ 4,007
Property, plant and equipment, net	57,516	61,162
Total assets	$ 60,782	$ 65,169
Current liabilities	$ 438	$ 1,224
Combined equity	60,344	63,945
Total liabilities and combined equity	$ 60,782	$ 65,169

	For Year Ended December 31,		
	2004	**2003**	**2002**
INCOME STATEMENT DATA:			
Revenues	$ 18,378	$ 14,512	$ 12,209
Operating income	5,131	2,726	2,232
Net income	5,151	2,685	2,243

Other, Non-segment

The Other, non-segment category is presented for financial reporting purposes only to show the historical equity earnings we received from our 50% membership interest in the general partner of GulfTerra, *GulfTerra Energy Company, L.L.C.* ("GulfTerra GP"), which owns a 1.0% general partner interest in GulfTerra. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with Step One of the GulfTerra Merger (see Note 4). Our investment in GulfTerra GP was accounted for using the equity method until the GulfTerra Merger was completed on September 30, 2004. On that date, GulfTerra GP became a wholly owned consolidated subsidiary of ours. Since the historical equity earnings of GulfTerra GP were based on net income amounts allocated to it by GulfTerra, it is impractical for us to allocate the equity income we received during the periods presented to each of our new segments. Therefore, we have segregated equity earnings from GulfTerra GP apart from our other investments to aid in comparability between the periods presented and future periods.

8. INTANGIBLE ASSETS AND GOODWILL

Intangible assets. The following table summarizes our intangible assets at the dates indicated:

		At December 31, 2004		At December 31, 2003	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Offshore Pipelines & Services:					
Pipeline & platform customer relationships (1)	$ 205,845	$ (6,965)	$ 198,880		
Independence Hub	1,167		1,167		
Segment total	207,012	(6,965)	200,047		
Onshore Natural Gas Pipelines & Services:					
San Juan Gathering System customer relationships (1)	331,311	(6,222)	325,089		
Permian Basin customer relationships (1)	1,590	(57)	1,533		
Petal natural gas storage contracts (1)	86,726	(1,558)	85,168		
Hattiesburg natural gas storage contracts (1)	13,773	(501)	13,272		
San Juan Basin water rights (1)	750	(6)	744		
Segment total	434,150	(8,344)	425,806		
NGL Pipelines & Services:					
Shell natural gas processing agreement	206,216	(45,110)	161,106	$ (34,063)	$ 172,153
Toca-Western natural gas processing contracts	11,187	(1,444)	9,743	(885)	10,302
Toca-Western NGL fractionation contracts	20,042	(2,589)	17,453	(1,587)	18,455
Mont Belvieu Storage II contracts	8,127	(697)	7,430	(464)	7,663
Venice contracts	6,635	(601)	6,034	(136)	6,499
STMA customer relationships (1)	37,802	(1,308)	36,494		
NGL Business customer relationships (1)	32,800	(829)	31,971		
Markham NGL storage contracts (1)	32,664	(1,088)	31,576		
Morgan's Point (2)	1,652		1,652		
Segment total	357,125	(53,666)	303,459	(37,135)	215,072
Petrochemical Services:					
Mont Belvieu Splitter III contracts	53,000	(4,417)	48,583	(2,902)	50,098
BEF UOP License Fee	1,097	(109)	988	(24)	1,633
Port Neches pipeline contracts	2,400	(682)	1,718	(310)	2,090
Segment total	56,497	(5,208)	51,289	(3,236)	53,821
Total all segments	$ 1,054,784	$ (74,183)	$ 980,601	$ (40,371)	$ 268,893

(1) These intangible assets were acquired as a result of the GulfTerra Merger and the South Texas midstream assets in September 2004. These amounts are based on our preliminary purchase price allocation for the GulfTerra Merger (see Note 4), which is subject to change.

(2) These intangible assets were acquired in December 2004 in connection with our acquisition of the Morgan's Point assets. The amounts assigned to intangible assets are based upon our preliminary allocation of the acquisition purchase price, which is subject to change.

As of December 31, 2004, our primary intangible assets were as follows:

- *GulfTerra and STMA customer relationships.* These intangible assets represent the customer base that GulfTerra and the South Texas midstream assets serve through providing services, including natural gas gathering and processing, NGL fractionation and pipeline transportation. These entities conduct the majority of their business through the use of written contracts; thus, the customer relationships represent the rights we own arising from those contractual agreements. We amortize the customer relationship values using a method that closely resembles the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are consumed or otherwise used. This group of intangible assets consists of our (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Permian Basin customer relationships; (iv) STMA customer relationships and (v) NGL Business customer relationships.

- *GulfTerra storage contracts.* These intangible assets represent the contracts that GulfTerra entered into to provide for the storage of natural gas or NGLs for various customers at its Petal and Hattiesburg natural gas or Markham NGL storage facilities. These contracts are amortized on a straight-line basis over the remainder of their respective contract terms, which we estimate range from 2 to 18 years. This group of intangible assets consists of our (i) Petal natural gas storage contracts; (ii) Hattiesburg natural gas storage contracts and (iii) Markham NGL storage contracts.

- *Shell natural gas processing agreement*. We acquired this intangible asset in connection with our acquisition of certain midstream energy assets from Shell located along the Gulf Coast in 1999. The value of the Shell agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019. For additional information regarding our related party relationship with Shell, see Note 14.

- *Mont Belvieu storage and propylene fractionation contracts*. We acquired these storage and propylene fractionation contracts during 2002 in connection with our purchase of certain midstream energy assets from Diamond-Koch that were located in Mont Belvieu, Texas. The values of these contracts are being amortized on a straight-line basis over the 35-year remaining economic life of the assets to which they relate. This group of intangible assets consists of our Mont Belvieu Storage II contracts and Mont Belvieu Splitter III contracts.

- *Toca-Western contracts*. We acquired these natural gas processing and NGL fractionation contracts during 2002 in connection with our purchase of certain midstream energy assets from Toca-Western. The Toca-Western natural gas processing contracts are being amortized on a straight-line basis over the expected 20-year economic life of the natural gas supplies supporting these contracts. The value of the Toca-Western NGL fractionation contracts is being amortized on a straight-line basis over the expected 20-year remaining life of the assets to which they relate.

Our remaining intangible assets primarily represent the value of contracts rights we own under product handling and transportation agreements, processing license agreements and water rights. In general, the value of these contract rights are being amortized using the straight-line method over either the terms of underlying contracts or the remaining useful economic life of the assets to which they relate.

Goodwill. In general, goodwill represents the excess of the purchase price of an acquired entity over the amounts assigned to assets acquired (including identifiable intangible assets) and liabilities assumed. Goodwill is not amortized; however, it is subject to annual impairment testing. Our preliminary estimate of goodwill associated with the GulfTerra Merger is $376.8 million, which we allocated between our new business segments in proportion to the tangible and intangible assets we recorded for this transaction in purchase accounting. The "GulfTerra Merger" goodwill is associated with our view of the future results from GulfTerra's operations, based on the strategic location of GulfTerra's assets as well as their industry relationships. Based on miles of pipelines, GulfTerra is one of the largest natural gas gathering and transportation companies providing services to producers in the natural gas supply regions of the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions, especially the deepwater regions of the Gulf of Mexico, offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure. Since we have not finalized our allocation of the purchase price associated with the GulfTerra Merger, our estimate of goodwill related to this transaction is preliminary (see Note 4). The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our purchase of propylene fractionation assets from Diamond-Koch in February 2002.

The following table summarizes our goodwill amounts at the dates indicated:

	At December 31,	
	2004	**2003**
Offshore Pipelines & Services		
GulfTerra Merger	$ 62,348	
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	290,397	
NGL Pipelines & Services		
GulfTerra Merger	24,026	
Acquisition of interest in Mont Belvieu NGL fractionator	7,857	$ 7,857
Acquisition of interest in Wilprise	880	880
Petrochemical Services		
Acquisition of Mont Belvieu propylene fractionation assets	73,690	73,690
Totals	$ 459,198	$ 82,427

The following table shows amortization expense associated with our intangible assets for the periods indicated:

	For Year Ended December 31,		
	2004	2003	2002
Offshore Pipelines & Services	$ 6,965		
Onshore Natural Gas Pipelines & Services	8,344		
NGL Pipelines & Services	16,531	$ 12,977	$ 12,197
Petrochemical Services	1,973	1,848	1,388
Total all segments	$ 33,813	$ 14,825	$ 13,585

For 2005, amortization expense attributable to these intangible assets is currently estimated at $86.5 million. Based on information currently available, we estimate that amortization expense related to existing intangible assets could approximate $80.2 million during 2006, $75.1 million during 2007, $70.5 million during 2008 and $65.9 million during 2009.

9. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

	December 31, 2004	December 31, 2003
Operating Partnership debt obligations:		
Interim Term Loan, variable rate, repaid in May 2004 (1)		$ 225,000
364-Day Revolving Credit Facility, variable rate, terminated in September 2004 (2)		70,000
Multi-Year Revolving Credit Facility, variable rate, terminated in September 2004 (2)		115,000
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (3, 4)	$ 242,229	
Multi-Year Revolving Credit Facility, variable rate, due September 2009 (2,4)	321,000	
Seminole Notes, 6.67% fixed-rate, $15 million due in December 2005 (5)	15,000	30,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes A, 8.25% fixed-rate, repaid March 2005	350,000	350,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000	
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	
GulfTerra debt obligations: (5)		
Senior Notes, 6.25% fixed-rate, due June 2010 (6)	750	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2010	3,858	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2011	1,777	
Senior Subordinated Notes, 10.625% fixed-rate, due December 2012	84	
Total principal amount	4,288,698	2,144,000
Net unamortized discounts	(9,239)	(5,983)
Other	1,777	1,531
Subtotal long-term debt	4,281,236	2,139,548
Less current maturities of debt (7)	(15,000)	(240,000)
Long-term debt	$ 4,266,236	$ 1,899,548
Standby letters of credit outstanding (8)	$ 139,052	$ 1,300

(1) We used the proceeds from our May 2004 common unit offering to fully repay and terminate the Interim Term Loan.
(2) These facilities were terminated on September 30, 2004, and replaced by a new Multi-Year Revolving Credit Facility having $750 million of borrowing capacity due September 2009.
(3) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility.
(4) These facilities became effective concurrently with the closing of the GulfTerra Merger on September 30, 2004. The new $750 million Multi-Year Revolving Credit Facility replaced the $230 million 364-Day Revolving Credit Facility and the $270 million then existing Multi-Year Revolving Credit Facility. The $750 million borrowing capacity is reduced by the amount of standby letters of credit outstanding.
(5) Solely as it relates to the assets of our GulfTerra and Seminole subsidiaries, our senior indebtedness is structurally subordinated and ranks junior in right of payment to indebtedness of GulfTerra and Seminole.
(6) Remaining notes outstanding were called and retired in February 2005.
(7) In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*," long-term and current maturities of debt at December 31, 2004 reflected (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment of our 364-Day Acquisition Credit Facility using proceeds from an equity offering completed in February 2005. Our classification of current maturities of debt at December 31, 2003 reflected our option and ability to convert any revolving credit balance outstanding at maturity under the 364-Day Revolving Credit Facility to a one-year term loan (which would have been due October 2005) in accordance with the terms of the agreement.
(8) Of the $139 million standby letters of credit outstanding at December 31, 2004, $24 million were issued under our Multi-Year Revolving Credit Facility, and the remaining $115 million is associated with a letter of credit facility we entered into in November 2004 in connection with our Independence Hub capital project.

General Description of Consolidated Debt

The following is a summary of the significant aspects of our debt obligations at December 31, 2004:

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes and the senior and senior subordinated notes of GulfTerra. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 88.4% of its capital stock). The senior and senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

GulfTerra's Senior Subordinated and Senior Notes. As a result of completing the GulfTerra Merger on September 30, 2004, we recorded in consolidation GulfTerra's $921.5 million of outstanding senior and senior subordinated notes. Of this amount, $915 million was purchased on October 5, 2004 by our Operating Partnership pursuant to its tender offers. The note holders also approved amendments in connection with accepting the tender offers that removed all restrictive covenants governing the notes. For additional information regarding the tender offers, please read " – *364-Day Acquisition Credit Facility – Tender offers for GulfTerra senior and senior subordinated notes*" within this general description of debt. In February 2005, we redeemed, at a premium, the remaining $0.8 million outstanding under GulfTerra's 6.25% senior notes due June 2010.

364-Day Acquisition Credit Facility. In August 2004, our Operating Partnership entered into a new 364-day credit agreement. The $2.25 billion Acquisition Credit Facility was an unsecured 364-day facility that was used to provide interim financing for certain transactions associated with the GulfTerra Merger, the refinancing of GulfTerra's existing secured credit facility and term loans and the purchase of GulfTerra's senior and senior subordinated notes in connection with our Operating Partnership's tender offers for those notes. This facility became effective concurrent with the closing of the GulfTerra Merger and was to mature on September 29, 2005. In February 2005, we fully repaid and terminated the 364-Day Acquisition Credit Facility using proceeds we received from our February 2005 common unit offering. For additional information regarding the February 2005 common unit offering, see Note 21.

As defined by the credit agreement, variable interest rates charged under this facility generally bore interest, at our election at the time of each borrowing, at (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate.

This credit agreement provided for the mandatory prepayment of loans and termination of commitments equal to the proceeds from and upon the consummation of any public or private debt or equity offerings by us on or after August 15, 2004, excluding equity issued with respect to our distribution reinvestment plan, employee unit purchase plan and the exercise of any outstanding options with respect to our common units. With the completion of our private offering of senior notes on October 4, 2004, we repaid approximately $2 billion borrowed under this facility, which reduced our borrowing capacity under this facility by an equal amount.

This revolving credit agreement contained various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also required us to satisfy certain financial covenants at the end of each fiscal quarter. We are in compliance with these covenants at December 31, 2004.

Tender offers for GulfTerra senior and senior subordinated notes

On August 4, 2004, in anticipation of completing the GulfTerra Merger, our Operating Partnership commenced four cash tender offers to purchase any and all of the outstanding senior and senior subordinated notes of GulfTerra having a total outstanding principal amount of approximately $921.5 million. In connection with the tender offers, GulfTerra executed supplements to the indentures governing these notes that eliminated certain restrictive covenants and default provisions contained in those indentures upon our purchase of more than a majority in principal amount of each series of the outstanding senior and senior subordinated notes.

Substantially all of the GulfTerra notes ($915 million of $921.5 million) were tendered pursuant to the tender offers. On September 30, 2004, we borrowed $1.1 billion under our 364-Day Acquisition Credit Facility in anticipation of completing the tender offers and placed these funds in escrow. On October 5, 2004, our Operating Partnership purchased the notes for a total price of approximately $1.1 billion, which included $27 million related to consent payments.

The following table shows the four GulfTerra senior debt obligations affected, including the principal amount of each series of notes tendered, as well as the payment made by Enterprise to complete the tender offers.

Description	Principal Amount Tendered	Cash payments made by Enterprise: Accrued Interest	Tender Price [1]	Total Paid
8.50% Senior Subordinated Notes due 2010				
(Represents 98.2% of principal amount outstanding)	$ 212,057	$ 6,209	$ 246,366	$ 252,575
10.625% Senior Subordinated Notes due 2012				
(Represents 99.9% of principal amount outstanding)	133,916	4,901	167,612	172,513
8.50% Senior Subordinated Notes due 2011				
(Represents 99.5% of principal amount outstanding)	319,823	9,364	359,379	368,743
6.25% Senior Notes due 2010				
(Represents 99.7% of principal amount outstanding)	249,250	5,366	274,073	279,439
Totals	$ 915,046	$ 25,840	$ 1,047,430	$ 1,073,270

(1) Tender price includes consent payment of $30 per $1,000 principal amount tendered.

Multi-Year Revolving Credit Facility. In August 2004, our Operating Partnership entered into a five-year $750 million revolving credit agreement that includes a sublimit of $100 million for standby letters of credit. This facility became effective concurrent with the closing of the GulfTerra Merger and will mature on September 30, 2009. This facility replaced our then existing $270 million Multi-Year Revolving Credit Facility and $230 million 364-Day Revolving Credit Facility, which were terminated upon the effective date of the new facility. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

As defined by the credit agreement, variable interest rates charged under this facility generally bear interest, at our election at the time of each borrowing, at (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate. This revolving credit agreement contains various covenants similar to those of our 364-Day Acquisition Credit Facility. We are in compliance with these covenants at December 31, 2004.

Senior Notes A, B, C and D. These fixed-rate notes are an unsecured obligation of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants. These covenants restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We were in compliance with these covenants at December 31, 2004. On March 15, 2005, we repaid the $350 million in indebtedness outstanding under Senior Notes A using the proceeds we received from our February 2005 private offering of senior notes. See Note 21 for information regarding this subsequent event.

Senior Notes E, F, G and H. On September 23, 2004, our Operating Partnership priced a private offering of an aggregate of $2 billion in principal amount of senior unsecured notes in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended. On October 4, 2004, these notes were issued. The interest rate, principal amount and net proceeds, before expenses, for each senior note in this offering are shown in the following table:

Senior Note Issued	Fixed Interest Rate	Principal Amount	Bond Discount	Proceeds to Us, Before Expenses
Senior Notes E, due October 2007	4.000%	$ 500,000	$ 2,140	$ 497,860
Senior Notes F, due October 2009	4.625%	500,000	4,405	495,595
Senior Notes G, due October 2014	5.600%	650,000	4,784	645,216
Senior Notes H, due October 2034	6.650%	350,000	4,203	345,797
Totals		$ 2,000,000	$ 15,532	$ 1,984,468

The net proceeds from this offering were used to reduce debt amounts outstanding under the Operating Partnership's $2.25 billion 364-Day Acquisition Credit Facility that was used to partially fund the GulfTerra Merger on September 30, 2004.

These fixed-rate notes are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes were issued under an indenture containing certain covenants, which restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions. We are in compliance with these covenants at December 31, 2004.

On January 24, 2005, we filed a registration statement for an offer to exchange these notes for registered debt securities with identical terms. The exchange of notes was completed in March, 2005.

Senior Notes Offering. On February 15, 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a private offering. See Note 21 for information regarding this subsequent event.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, our Operating Partnership entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by us through an unsecured and unsubordinated guarantee. The Pascagoula MBFC Loan contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility. We were in compliance with the covenants at December 31, 2004.

The indenture agreement for this loan contains an acceleration clause whereby if our credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or below, the $54 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Petal Industrial Development Revenue Bonds. In April 2004, Petal Gas Storage L.L.C. ("Petal"), a wholly owned subsidiary of GulfTerra, borrowed $52 million from the MBFC pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52 million in Industrial Development Revenue Bonds to another wholly owned subsidiary of GulfTerra. The loan agreement and the Industrial Development Revenue Bonds have identical fixed interest rates of 6.25% and maturities of fifteen years. The bonds and the associated tax exemptions are authorized under the Mississippi Business Finance Act. Petal may repay the loan agreement without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $2.2 million on our Consolidated Balance Sheet as of December 31, 2004. Beginning in the fourth quarter of 2004, we also netted the interest expense and interest income amounts of $0.8 million attributable to these instruments on our Statements of Consolidated Operations and Comprehensive Income. Our presentation of the Petal Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, "*Offsetting of Amounts Related to Certain Contracts*", and SFAS No. 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*", since we have the ability and intent to offset these items.

Loss due to write-off of unamortized debt issuance costs. As a result of terminating our 364-Day Revolving Credit Facility and our previous Multi-Year Revolving Credit Facility on September 30, 2004, we expensed $0.7 million of unamortized debt issuance costs.

Information Regarding Variable Interest Rates Paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations during 2004.

	Range of interest rates paid	Weighted-average interest rate paid
Interim Term Loan (terminated May 2004)	1.72% to 1.78%	1.76%
364-Day Revolving Credit Facility (terminated September 30, 2004)	1.72% to 4.00%	1.82%
Multi-Year Revolving Credit Facility (terminated September 30, 2004)	1.67% to 4.25%	1.83%
364-Day Acquisition Credit Facility (effective September 30, 2004)	2.67% to 4.75%	3.50%
Multi-Year Revolving Credit Facility (effective September 30, 2004)	2.64% to 5.25%	3.06%

Consolidated Debt Maturity Table

The following table shows scheduled maturities of the principal amounts of our debt obligations for the next 5 years and in total thereafter.

Fiscal 2005	$	15,000
" 2007		500,000
" 2009		821,000
Thereafter		2,952,698
Total scheduled principal to be repaid	$	4,288,698

In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*", the amount shown in the table above for 2005 excludes the $242.2 million principal amount due under our 364-Day Acquisition Credit Facility at December 31, 2004. We refinanced this short-term obligation using proceeds from an equity offering completed in February 2005. As a result, we have reclassified this amount to long-term debt and shown it as a component of principal amounts due after 2009.

In addition, the long-term portion of our debt obligations at December 31, 2004 reflects our refinancing of the $350 million in principal amount Senior Notes A (due March 2005) with proceeds from our issuance in March 2005 of $250 million in principal amount Senior Notes I (due March 2015) and our $250 million in principal amount Senior Notes J (due March 2035). In accordance with SFAS No. 6, the principal amount due under Senior Notes A has been reclassified to amounts due after 2009 to match the scheduled maturities of Senior Notes I and J.

Joint Venture Debt Obligations

We have ownership interests in four joint ventures having long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2004, (ii) total long-term debt obligations (including current maturities) of each unconsolidated affiliate at December 31, 2004, on a 100% basis to the joint venture and (iii) the corresponding scheduled maturities of such long-term debt.

	Our Ownership Interest	Total	Scheduled Maturities of Long-Term Debt					
			2005	2006	2007	2008	2009	After 2009
Cameron Highway [1]	50.0%	$ 297,000		$ 8,125	$ 32,500	$ 164,375	$ 16,000	$ 76,000
Deepwater Gateway	50.0%	144,000	$ 22,000	22,000	22,000	22,000	56,000	
Poseidon	36.0%	107,000				107,000		
Evangeline	49.5%	35,650	5,000	5,000	5,000	5,000	5,000	10,650
Total		$ 583,650	$ 27,000	$ 35,125	$ 59,500	$ 298,375	$ 77,000	$ 86,650

(1) The scheduled maturities for Cameron Highway assume that the construction loan will be converted into a term loan by July 2005 and scheduled repayments will begin on December 31, 2006.

The following is a summary of the significant aspects of the debt obligations of our unconsolidated affiliates.

Cameron Highway. In July 2003, Cameron Highway entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, to finance a substantial portion of the cost to construct the Cameron Highway oil pipeline.

The construction loan bears interest at a variable rate. Once the Cameron Highway oil pipeline has commenced operations and transported a certain level of volumes (as specified in the credit agreement), the construction loan will convert to a term loan maturing in 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 $8.1 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by January 2006, the construction loan and senior secured notes become fully due and payable. At December 31, 2004, Cameron Highway had $197 million outstanding under its construction loan at an average interest rate of 5.48%.

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, 2004, Cameron Highway had $100 million outstanding under its senior secured notes at an average interest rate of 7.36%.

The project loan facility as a whole is secured by (1) substantially all of Cameron Highway's assets, including, upon conversion to a term loan, 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, 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.

Deepwater Gateway. In August 2002, Deepwater Gateway, our unconsolidated affiliate which owns the Marco Polo tension-leg platform, obtained a $155 million project finance loan to finance a substantial portion of the cost to construct the Marco Polo tension-leg platform and related facilities. Construction of the Marco Polo tension-leg platform was completed during the first quarter of 2004, and in June 2004, Deepwater Gateway converted the project finance loan into a term loan which matures in June 2009. The term loan is payable in twenty equal quarterly installments of $5.5 million each (which began on September 30, 2004), and the remaining outstanding principal of $45 million is due on the maturity date. Interest rates are variable and the loan is collateralized by substantially all of Deepwater Gateway's assets. Deepwater Gateway is 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. If Deepwater Gateway defaults on its payment obligations under the term loan, we would be required to pay the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2004, the average interest rate charged under this term loan was 4.42%.

In accordance with terms of the credit agreement, Deepwater Gateway has the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway has decided to extinguish its term loan. We and our 50% joint venture partner in Deepwater Gateway, Cal Dive, will make equal cash contributions to Deepwater Gateway to fund the repayment. At March 9, 2005, the term loan principal amount owed by Deepwater Gateway was $144 million.

Poseidon. Poseidon is party to a $170 million revolving credit facility which matures in January 2008. The interest rates Poseidon is charged on balances outstanding under its revolving credit facility are variable and depend on its ratio of total debt to earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon's assets. As of December 31, 2004, the average interest rate charged under Poseidon's revolving credit facility was 4.58%.

Evangeline. At December 31, 2004, long-term debt for Evangeline consisted of (i) $28.2 million in principal amount of 9.9% fixed-rate Series B senior secured notes that are due in December 2010 and (ii) a $7.5 million subordinated note payable. The Series B senior secured notes are collateralized by Evangeline's property, plant and equipment; proceeds from a gas sales contract; and by a debt service requirement. Scheduled principal repayments on the Series B notes are $5 million annually through 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios. Evangeline incurred the subordinated note payable in connection with its acquisition of a contract-based intangible asset in the early 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders are either fully cash secured through debt service accounts or have been completely repaid. In general, interest accrues on the subordinated note at a variable-rate based on LIBOR plus ½%. The variable interest rate paid on this debt at December 31, 2004 was 1.73%.

10. CAPITAL STRUCTURE

General. Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fourth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). Our common units trade on the NYSE under the ticker symbol "EPD." We are managed by our general partner, Enterprise GP.

On October 1, 2004, we amended and restated our Partnership Agreement by executing the Fourth Amended and Restated Agreement of Limited Partnership. The amended Partnership Agreement makes the following changes: (i) all previous amendments were consolidated into one document, (ii) certain provisions which are no longer applicable to us were deleted (such as those relating to the subordination period and classes of partnership equity securities that are no longer outstanding), and (iii) certain provisions were added to evidence our separateness from other persons and entities. A number of additional immaterial revisions were made in the amended Partnership Agreement, including updating definitions to provide consistency with the above described changes.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and Enterprise GP will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated 100% to our general partner. See Note 11 for information regarding our cash distributions to partners, including incentive cash distributions to Enterprise GP.

Capital accounts, under the Partnership Agreement, are maintained for our general partner and our limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

Equity offerings. The Partnership Agreement generally authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as shall be established by Enterprise GP in its sole discretion without the approval of unitholders. Since October 2002, we have completed a number of common unit offerings. The following table reflects the number of common units issued and the net proceeds received from each offering:

		Net Proceeds			
Month of Offering	**Number of Common Units Issued**	**Contributed by Limited Partners**	**Contributed by General Partner**	**Contributed by General Partner In Minority Interest** (1)	**Total**
October 2002 (2)	9,800,000	$ 178,859	$ 1,807	$ 1,844	$ 182,510
January 2003 (3)	14,662,500	$ 252,942	$ 2,555	$ 2,608	$ 258,105
June 2003 (4)	11,960,000	255,891	2,584	2,639	261,114
August 2003 (5)	1,306,059	26,416	266	280	26,962
November 2003 (5)	1,577,744	32,696	334	334	33,364
Total 2003	29,506,303	$ 567,945	$ 5,739	$ 5,861	$ 579,545
February 2004 (5)	1,053,861	$ 22,684	$ 463		$ 23,147
May 2004 (6)	17,250,000	346,032	7,062		353,094
May 2004 (5)	1,757,347	34,589	706		35,295
August 2004 (7)	17,250,000	334,358	6,824		341,182
August 2004 (5)	173,033	3,151	64		3,215
November 2004 (5)	2,199,350	48,944			49,942
Total 2004	39,683,591	$ 789,758	$ 16,117		$ 805,875

(1) Prior to the restructuring of Enterprise GP's ownership interest in December 2003, Enterprise GP owned 1.0101% of the Operating Partnership. This ownership interest was accounted for as a component of minority interest in our historical Consolidated Balance Sheets.

(2) We used $178.8 million of the proceeds from this offering to repay a portion of the indebtedness under our 364-Day Term Loan. The remaining proceeds were used for working capital purposes.

(3) We used $252.8 million of the proceeds from this offering to repay a portion of the indebtedness under our 364-Day Term Loan. The remaining proceeds were used for working capital purposes.

(4) We used the net proceeds from this offering to reduce indebtedness outstanding under our revolving credit facilities.

(5) These units were issued primarily in connection with the distribution reinvestment plan ("DRIP"). We used the proceeds from these offerings primarily for general partnership purposes.

(6) We used the proceeds from this public offering to repay the $225 million Interim Term Loan and to temporarily reduce borrowings outstanding under our revolving credit facilities.

(7) We used $210 million of the proceeds from this public offering to reduce borrowings outstanding under our revolving credit facilities and the remainder to fund our payment obligations to El Paso under Step Two of the GulfTerra Merger.

We have on file with the SEC a $1.5 billion universal shelf registration statement covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). In February 2005, we sold 17,250,000 common units in a public offering (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005), which generated net proceeds of approximately $456.5 million (see Note 21). As a result of this offering, practically all of the available capacity under this shelf registration statement has been used. In March 2005, we filed a new $4 billion universal shelf registration statement with the SEC (see Note 21).

During 2003, we instituted a distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional common units. In July 2003, we filed a registration statement with the SEC covering 5,000,000 common units issuable under the DRIP. In April 2004, we filed a new registration statement with the SEC covering an additional 10,000,000 common units issuable under the DRIP. The new registration statement increased the number of common units issuable under the DRIP from 5,000,000 to 15,000,000. As a result of any reinvestment proceeds we receive, Enterprise GP is required to make cash contributions to us in order to maintain its ownership interest. Initial reinvestments under this program occurred in August 2003.

Equity interests granted on September 30, 2004 in connection with the GulfTerra Merger. Under Step Two of the GulfTerra Merger (see Note 4), Enterprise issued 1.81 of its common units for each GulfTerra common unit (including restricted common units) remaining after Enterprise's purchase of 2,876,620 GulfTerra common units owned by El Paso. The 104,549,823 Enterprise common units (including restricted common units) issued in the conversion were calculated as shown in the following table:

GulfTerra units outstanding at September 30, 2004:	
Common units, including time-vested restricted common units	60,638,989
Series C units	10,937,500
Total historical units outstanding at September 30, 2004	71,576,489
Adjustments to GulfTerra historical units outstanding as a result of the GulfTerra Merger:	
Enterprise's purchase of GulfTerra Series C units from El Paso in connection with Step Two	(10,937,500)
Enterprise's purchase of GulfTerra common units from El Paso in connection with Step Two	(2,876,620)
GulfTerra common units outstanding subject to Step Two exchange offer by Enterprise	57,762,369
Conversion ratio (1.81 Enterprise common units for each GulfTerra common unit)	1.81
Enterprise common units issued to GulfTerra common unitholders in connection with GulfTerra Merger (adjusted for 65 fractional common units)	104,549,823
Average closing price per unit of Enterprise common units immediately prior to and after proposed GulfTerra Merger was announced on December 15, 2003 (see following table)	$ 23.39
Fair value of Enterprise common units issued in conversion of remaining GulfTerra common units	$ 2,445,420

In accordance with purchase accounting, the $2.4 billion value of Enterprise's common units issued in Step Two of the GulfTerra Merger is based on the average closing price of Enterprise's common units immediately prior to and after the proposed merger was announced on December 15, 2003:

December 11, 2003	$ 23.10
December 12, 2003	22.80
December 16, 2003	23.85
December 17, 2003	23.80
Average closing price per unit of Enterprise common units immediately prior to and after the proposed merger was announced on December 15, 2003	$ 23.39

Overall, the fair value of equity interests we issued on September 30, 2004 under Step Two of the GulfTerra Merger was approximately $2.9 billion. The following table shows the detail for this consideration:

Fair value of Enterprise common units issued in conversion of remaining GulfTerra common units	$ 2,445,420
Fair value of equity interests issued to acquire remaining 50% membership interest in GulfTerra GP (voting interest) (1)	461,347
Fair value of other Enterprise equity interests issued for unit awards and Series F2 convertible units (2)	4,005
Total value of equity interests issued upon closing of GulfTerra Merger	$ 2,910,772

(1) This fair value is based on 50% of an implied $922.7 million total value of GulfTerra GP, which assumes that the $370 million cash payment made by Enterprise GP to El Paso represented consideration for a 40.1% interest in GulfTerra GP. The 40.1% interest was derived by deducting the 9.9% membership interest in Enterprise GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise GP received. The fair value of $461.3 million assigned to this voting membership interest in GulfTerra GP compares favorably to the $425 million paid to El Paso by Enterprise to purchase its initial 50% non-voting membership interest in GulfTerra GP in December 2003. The contribution of this 50% membership interest to Enterprise is allocated for financial reporting purposes to Enterprise's limited partners and general partner based on the respective ownership percentages and the related allocation of profits and losses of 98% and 2%, respectively, both of which are consistent with the Partnership Agreement.

(2) See discussion of "Series F2 convertible units assumed in connection with the GulfTerra Merger" and "Restricted common units issued during 2004" included within this Note 10 for additional information.

Series F2 convertible units assumed in connection with the GulfTerra Merger. In May 2003, GulfTerra issued 80 Series F convertible units in a registered offering to an institutional investor. Each Series F convertible unit was comprised of two separate detachable units – a Series F1 convertible unit and a Series F2 convertible unit – that had identical terms except for vesting and termination dates and the number of common units into which they could be converted. Prior to the GulfTerra Merger, all the Series F1 convertible units were converted to GulfTerra common units by the holder. As a result of the GulfTerra Merger, we assumed GulfTerra's obligation associated with the 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive Enterprise common units. The number of Enterprise common units and the price per unit at conversion were adjusted based on the 1.81 exchange ratio. The Series F2 units were convertible into up to $40 million of Enterprise common units.

On October 29, 2004, 60 of the 80 outstanding Series F2 convertible units were converted into 1,458,434 Enterprise common units. As a result of this conversion, we received a payment of $30 million from the holder of the Series F2 convertible units (representing a conversion price of $20.57 per Enterprise common unit).

On November 8, 2004, the remaining 20 outstanding Series F2 convertible units were converted into 491,883 Enterprise common units. As a result of this conversion, we received a payment of $10 million from the holder of the Series F2 convertible units (representing a conversion price of $20.33 per Enterprise common unit).

The following table reflects the number of common units issued and the net proceeds received from the conversions of Series F2 convertible units into common units during 2004:

		Net Proceeds		
Month of Conversion	**Number of Common Units Issued**	**Contributed by Limited Partners**	**Contributed by General Partner**	**Total**
October 2004	1,458,434	$ 29,100	$ 594	$ 29,694
November 2004	491,883	9,700	198	9,898
Total 2004	1,950,317	$ 38,800	$ 792	$ 39,592

Restricted common units. We began issuing restricted common units to key employees of EPCO in May 2004. In general, our restricted common units are classified as either time-vested or performance-based. Time-vested restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) once the defined vesting period expires, subject to certain forfeiture provisions. The restrictions on time-vested restricted common units lapse four years from the date of grant. Unearned compensation, representing the fair market value of such restricted units at the date of issuance, is charged to earnings as compensation expense on a straight-line basis over the vesting period. During the vesting period, each holder of time-vested restricted units is entitled to receive cash distributions per unit in an amount equal to those received by our common unitholders. For basic and diluted earnings per unit purposes, time-vested restricted common units are treated as outstanding units.

In general, performance-based restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) if we achieve a specified level of financial performance for certain capital projects during 2007. If we do not reach the specified financial targets by the dates identified within each agreement, these units will be forfeited. Unearned compensation, representing the fair market value of these units at the date of issuance, is charged to earnings as compensation expense on a straight-line basis over the performance period. The performance-based restricted units are not entitled to vote or to receive distributions, until after (and if) we achieve the specified level of target performance. Lastly, performance-based restricted units are counted as outstanding units for dilutive earnings per unit purposes only.

During 2004, EPCO issued 434,225 time-vested restricted units to key management personnel of EPCO (who work on our behalf) as a means of retaining and compensating them for long-term performance and to increase their ownership in Enterprise. In addition, we issued 54,300 performance-based restricted common units to certain management personnel who joined us as a result of the GulfTerra Merger.

Total unamortized deferred compensation attributable to both classes of restricted units at December 31, 2004 was $10.9 million. We recorded $0.8 million of compensation expense for year ended December 31, 2004, which is reflected as a component of selling, general and administrative expenses. Deferred compensation is reflected as a reduction of partners' equity and allocated to our partners in accordance with their respective ownership interests.

Restructuring of general partner ownership interests in December 2003. In December 2003, we restructured Enterprise GP's ownership interest in us and our Operating Partnership from a 1% ownership in us and a 1.0101% ownership in the Operating Partnership to a 2% ownership in us. As a result, our effective ownership in the Operating Partnership increased to 100% from 98.9899%. The purpose of the restructuring was to simplify and reduce the cost of compliance with the SEC rules relating to financial reporting requirements of subsidiaries. As a result of the restructuring, the Operating Partnership became exempt from the reporting requirements of Section 15(d) of the Securities Exchange Act of 1934 pursuant to Rule 12h-5 thereunder.

Two-for-one unit split in February 2002. In February 2002, Enterprise GP approved a two-for-one split of each class of our partnership units. The unit split was accomplished by distributing one additional partnership unit for each partnership unit outstanding to holders of record on April 20, 2002. The units were distributed on May 15, 2002.

Conversion of Class B special units to common units. In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO, for $100 million in a private transaction. Enterprise GP contributed approximately $2 million in order to maintain its ownership interest. The purchase price for the Class B special units was $22.6575 per unit, representing a 5% discount from the $23.85 closing price of our common units on the NYSE on December 16, 2003. The 5% discount was consistent with the 5% discount available to all our unitholders under our distribution reinvestment plan.

On July 29, 2004, we requested that our common unitholders approve the conversion of all of the Class B special units into common units on a one-for-one basis at a special meeting that was held on July 29, 2004, to approve our merger with GulfTerra. On this date, our common unitholders approved the conversion and our 4,413,549 Class B special units converted to an equal number of common units. This conversion resulted in a reclassification of the $99 million capital account balance for the Class B special units to common units.

Prior to their conversion, the Class B special units had rights identical to our common units with respect to distributions and other matters. However, the Class B special units did not have voting rights and were not deemed to be outstanding for purposes of determining whether a quorum is present or whether the approval of the requisite number of holders of our units had been obtained.

Conversion of subordinated units to common units. During 2003, the remaining 32,114,804 subordinated units owned by EPCO converted to common units as a result of our satisfying certain financial tests. The subordinated units had no voting rights until their conversion to common units; however, they did receive allocations of income and loss. These conversions had no impact on our earnings per unit calculations or cash distributions since subordinated units were already included in both the basic and fully diluted earnings per unit calculations and were distribution bearing.

Conversion of Class A special units to common units. Class A special units were issued to Shell in conjunction with our acquisition of certain of Shell's U.S. Gulf Coast midstream energy assets in 1999 and a related contingent unit agreement. We issued 29,000,000 Class A special units in August 1999 in connection with the acquisition. Subsequently, Shell met certain performance criteria in 2000 and 2001 that obligated us to issue an additional 12,000,000 Class A special units to Shell (6,000,000 in August 2000 and 6,000,000 in August 2001) under a contingent unit agreement. Of the cumulative 41,000,000 Class A special units issued, 2,000,000 converted to common units in August 2000, 10,000,000 converted in August 2001, 19,000,000 converted in August 2002 and 10,000,000 converted in August 2003. These conversions had a dilutive impact on basic earnings per unit since they increase the number of common units used in the computation. Class A special units were excluded from the computation of basic earnings per unit because they did not share in income or loss nor were they entitled to cash distributions until they were converted to common units. Under NYSE rules, the conversion of the Class A special units to common units required the approval of a majority of common unitholders. An affiliate of EPCO (which owns a majority of outstanding common units) voted in favor of such conversion, which provided the necessary votes for approval.

Treasury units. During 1999, our Operating Partnership established its wholly owned EPOLP 1999 Grantor Trust (the "1999 Trust") to fund potential future obligations under the EPCO Agreement with respect to EPCO's long-term incentive plan (through the exercise of options granted to EPCO employees or directors of Enterprise GP). Beginning in 2000, we and the 1999 Trust were authorized by Enterprise GP to repurchase up to 2,000,000 publicly-held common units under a buy-back program. The repurchases will be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. Under the terms of the original buy-back program, common units repurchased by us were retired and common units repurchased by the 1999 Trust were classified as treasury units. In 2002, the buy-back program was modified to classify common units repurchased by us as treasury units. After deducting for those common units repurchased in prior periods, we and the 1999 Trust could repurchase under the buy-back program up to 618,400 publicly traded common units at December 31, 2004.

The common units repurchased by us or the 1999 Trust are accounted for in a manner similar to treasury stock under the cost method of accounting. For the purpose of calculating both basic and diluted earnings per unit (see Note 13), treasury units are not considered to be outstanding.

During 2002, 532,000 common units were repurchased at a cost of $12.8 million and placed in treasury. During 2003, we reissued 30,887 treasury units at a cost of $0.6 million primarily due to our obligations under EPCO employee unit option agreements and recorded a small gain on the transactions. We also retired 30,000 treasury units during 2003 at a cost of $0.6 million to us. During 2004, we reissued 371,113 treasury units at a cost of $7.9 million primarily due to our obligations under EPCO employee unit option agreements and recorded a small gain on the transactions.

Changes in Limited Partners' Equity. The following table details the changes in limited partners' equity since January 1, 2002:

	Common units	Restricted Common units	Subord. units	Class A Special units	Class B Special units	Total
Balance, January 1, 2002	$ 651,872		$ 193,107	$ 296,634		$ 1,141,613
Net income	69,636		15,201			84,837
Operating leases paid by EPCO	6,872		2,071			8,943
Cash distributions to partners	(153,449)		(49,564)			(203,013)
Conversion of 19 million Class A special units to common units	152,708			(152,708)		
Conversion of 10.7 million subordinated units to common units	44,265		(44,265)			
Proceeds from issuance of common units	178,859					178,859
Treasury units reisssued to satisfy unit options	(928)		(262)			(1,190)
Balance, December 31, 2002	$ 949,835		$ 116,288	$ 143,926		$ 1,210,049
Net income	73,075		10,566		$ 176	83,817
Operating leases paid by EPCO	8,154		751		8	8,913
Other expenses paid by EPCO	435				(2)	433
Cash distributions to partners	(256,832)		(30,482)			(287,314)
Conversion of 10 million Class A special units to common units	143,926			(143,926)		
Conversion of 10.7 million subordinated units to common units	97,123		(97,123)			
Proceeds from issuance of common units	567,945					567,945
Proceeds from issuance of Class B special units					100,000	100,000
Restructuring of Enterprise GP ownership in our Operating Partnership	(73)					(73)
Treasury unit transactions:						
- Reissued to satisfy unit options	6					6
- Retired	(643)					(643)
Balance, December 31, 2003	$ 1,582,951		$ -	$ -	$ 100,182	$ 1,683,133
Net income	229,016	$ 142			1,995	231,153
Operating leases paid by EPCO	7,449	2			100	7,551
Cash distributions to partners	(394,741)	(218)			(3,288)	(398,247)
Proceeds from sales of common units	789,758					789,758
Proceeds from conversion of Series F2 convertible units to common units	38,800					38,800
Proceeds from exercise of unit options	398					398
Conversion of Class B special units to Common units	98,993				(98,993)	
Value of equity interests granted to Complete the GulfTerra Merger	2,851,796	2,479				2,854,275
Other issuance of restricted units		9,922				9,922
Treasury units reissued to satisfy unit options	520				4	524
Balance, December 31, 2004	$5,204,940	$ 12,327	$ -	$ -	$ -	$ 5,217,267

Unit History table. The following table details the outstanding balance of each class of units for the periods and at the dates indicated:

	Common Units	Restricted Common Units	Subord. Units	Class A Special Units	Class B Special Units	Treasury Units
Balance, January 1, 2002	102,721,830		42,819,740	29,000,000		327,200
Conversion of Class A special units to common units in August 2002	19,000,000			(19,000,000)		
Conversion of subordinated units to common units in August 2002	10,704,936		(10,704,936)			
Common units issued in October 2002	9,800,000					
Treasury unit purchases	(532,000)					532,000
Balance, December 31, 2002	141,694,766		32,114,804	10,000,000		859,200
Common units issued in January 2003	14,662,500					
Conversion of subordinated units to common units in May 2003	10,704,936		(10,704,936)			
Common units issued in June 2003	11,960,000					
Conversion of Class A special units to common units in August 2003	10,000,000			(10,000,000)		
Conversion of subordinated units to common units in August 2003	21,409,868		(21,409,868)			
Common units issued in August 2003	1,306,059					
Common units issued in November 2003	1,578,389					
Common units issued in December 2003	20,000					
Class B special units issued in December 2003					4,413,549	
Treasury unit transactions:						
Reissued to satisfy unit options	30,242					(30,887)
Retired						(30,000)
Balance, December 31, 2003	213,366,760		-	-	4,413,549	798,313
Common units issued in February 2004	1,053,861					
Common units issued in connection with May 2004 offering	17,250,000					
Other common units issued in May 2004	1,757,347					
Restricted common units issued in May 2004		81,500				
Conversion of Class B special units to common units in July 2004	4,413,549				(4,413,549)	
Common units issued in connection with August 2004 offering	17,250,000					
Other common units issued in August 2004	173,033					
Common and restricted common units issued to GulfTerra unitholders on September 30, 2004 in connection with the GulfTerra Merger	104,495,523	54,300				
Other restricted common units issued in September		32,500				
Common units issued in connection with conversion of Series F2 units in October 2004	1,458,434					
Restricted common units issued in October 2004		307,460				
Common units issued in connection with conversion of Series F2 units in November 2004	491,883					
Other common and restricted common units issued in November 2004	2,215,837	12,765				
Treasury units reissued to satisfy unit options	371,113					(371,113)
Balance, December 31, 2004	364,297,340	488,525	-	-	-	427,200

11. DISTRIBUTIONS

We expect, to the extent there is sufficient available cash from Operating Surplus (as defined by the Partnership Agreement) to distribute to each holder of common units at least a minimum quarterly distribution of $0.225 per common unit. The minimum quarterly distribution is not guaranteed and is subject to adjustment as set forth in the Partnership Agreement.

As an incentive, Enterprise GP's percentage interest in our quarterly cash distributions is increased after certain specified target levels of distribution rates are met. In December 2002, we amended our Partnership Agreement to eliminate the Enterprise GP's right to receive 50% of our quarterly cash distributions with respect to that portion of the distribution based on declared rates that exceed $0.392 per common unit. Furthermore, Enterprise GP has capped its incentive distribution rights at 25% of our quarterly cash distributions with respect to that portion of the distribution based on declared rates that exceed $0.3085 per common unit. No consideration was paid to Enterprise GP to give up this right. As amended, Enterprise GP's quarterly incentive distribution thresholds are as follows (which include adjustments for the December 2003 restructuring of the Enterprise GP's ownership interest in us and our Operating Partnership):

- 2% of quarterly cash distributions up to $0.253 per unit;
- 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and
- 25% of quarterly cash distributions that exceed $0.3085 per unit.

We made incentive distributions to Enterprise GP of $32.4 million, $19.7 million and $9.8 million during the years ended December 31, 2004, 2003 and 2002, respectively.

The following table summarizes quarterly cash distribution rates per unit during the periods indicated and the related record and distribution payment dates.

	Cash Distribution History		
	Distribution per Unit (1)	Record Date	Payment Date
2002			
1st Quarter	$0.3350	Apr. 30, 2002	May 10, 2002
2nd Quarter	$0.3350	Jul. 31, 2002	Aug. 12, 2002
3rd Quarter	$0.3450	Oct. 31, 2002	Nov. 12, 2002
4th Quarter	$0.3450	Jan. 31, 2003	Feb. 12, 2003
2003			
1st Quarter	$0.3625	Apr. 30, 2003	May 12, 2003
2nd Quarter	$0.3625	Jul. 31, 2003	Aug. 11, 2003
3rd Quarter	$0.3725	Oct. 31, 2003	Nov. 12, 2003
4th Quarter	$0.3725	Jan. 30, 2004	Feb. 11, 2004
2004			
1st Quarter	$0.3725	Apr. 30, 2004	May 12, 2004
2nd Quarter	$0.3725	Jul. 30, 2004	Aug. 11, 2004
3rd Quarter	$0.3950	Oct. 29, 2004	Nov. 5, 2004
4th Quarter	$0.4000	Jan. 31, 2005	Feb. 14, 2005

(1) Distributions are paid on common units, and prior to their conversion to common units, on subordinated units and Class B special units as well.

The quarterly cash distribution amounts shown in the table correspond to the cash flows for the quarters indicated. The actual cash distributions occur within 45 days after the end of such quarter.

12. PROVISION FOR INCOME TAXES FOR CERTAIN PIPELINE OPERATIONS

Our provision for income taxes is limited to certain income-based state franchise tax obligations of our Mid-America and Seminole pipelines and federal tax obligations of our Seminole pipeline (both pipeline systems were acquired in 2002). One of our subsidiaries, which owns the Seminole pipeline, is a corporation and substantially our only consolidated entity subject to federal income taxes. The following table summarizes our provision for income taxes for the periods indicated:

	For Year Ended December 31,		
	2004	2003	2002
Current:			
Federal tax benefit			$ (391)
State tax expense (benefit)	$ 157	$ 47	(55)
Total current	157	47	(446)
Deferred:			
Federal	1,620	4,556	1,812
State	1,984	690	268
Total deferred	3,604	5,246	2,080
Provision for income taxes	$ 3,761	$ 5,293	$ 1,634

Net deferred tax assets primarily relate to federal tax net operating loss carryovers and differences in the book and tax basis of property, plant and equipment. The federal tax net operating loss carryovers are projected to be utilized within the 20 year carryover period. A valuation allowance of $0.1 million was recorded in 2004 against the benefit of both the current year and all prior year state tax net operating losses. The state net operating loss carryovers are not expected to be utilized within the 5 year carryover period and will expire over the next 3 to 5 years.

13. EARNINGS PER UNIT

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units (i.e., common and restricted common units) outstanding during a period. The distribution-bearing Class B special units were included in the calculation of basic earnings per unit prior to their conversion to common units in July 2004.

In general, diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of:

- the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit);
- the weighted-average number of performance-based restricted common units outstanding during a period; and
- the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

The non-distribution bearing Class A special units were included in the calculation of diluted earnings per unit prior to their conversion to common units. Treasury units are not considered to be outstanding units; therefore, they are excluded from the computation of both basic and diluted earnings per unit.

In a period of net operating losses, the performance-based restricted units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. See Note 10 for information regarding our performance-based restricted units issued in September 2004. The dilutive incremental option units are calculated in accordance with the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the beginning of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

Beginning in August 2003, we started reissuing treasury units to satisfy our obligations under EPCO unit option agreements. The reissuance of these treasury units to satisfy EPCO's unit option liability has a dilutive effect on our earnings per unit. Prior to August 2003, EPCO had purchased practically all of the common units associated with its 1998 Plan in the open market. As a result, EPCO's unit option plan did not have any effect on our fully diluted earnings per unit in prior periods.

The amount of net income allocated to limited partner interests is derived by subtracting our general partner's share of our net income from net income. The following table shows the allocation of net income to our general partner for the periods indicated:

	For The Year Ended December 31,		
	2004	2003	2002
Net income	$ 268,261	$ 104,546	$ 95,500
Less incentive earnings allocations to Enterprise GP	(32,391)	(19,699)	(9,806)
Net income available after incentive earnings allocation	235,870	84,847	85,694
Multiplied by Enterprise GP ownership interest (1)	2.0%	1.2%	1.0%
Standard earnings allocation to Enterprise GP	$ 4,717	$ 1,030	$ 857
Incentive earnings allocation to Enterprise GP	$ 32,391	$ 19,699	$ 9,806
Standard earnings allocation to Enterprise GP	4,717	1,030	857
Enterprise GP interest in net income	$ 37,108	$ 20,729	$ 10,663

(1) Enterprise GP's ownership interest in us increased from 1% to 2% in December 2003 as a result of restructuring its overall ownership interest in us and our Operating Partnership (see Note 10). The 1.2% ownership interest shown for 2003 reflects the weighted-average of the Enterprise GP's ownership interest during the year.

The following tables show our calculation of limited partners' interest in net income, basic earnings per unit and diluted earnings per unit for the periods indicated:

	For The Year Ended December 31,		
	2004	2003	2002
Income before changes in accounting principles and Enterprise GP interest	$ 257,480	$ 104,546	$ 95,500
Cumulative effect of changes in accounting principles	10,781		
Net income	268,261	104,546	95,500
Enterprise GP interest in net income	(37,108)	(20,729)	(10,663)
Net income available to limited partners	$ 231,153	$ 83,817	$ 84,837
BASIC EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and Enterprise GP interest	$ 257,480	$ 104,546	$ 95,500
Cumulative effect of changes in accounting principles	10,781		
Enterprise GP interest in net income	(37,108)	(20,729)	(10,663)
Limited partners' interest in net income	$ 231,153	$ 83,817	$ 84,837
Denominator			
Common units	262,838	183,779	119,820
Restricted common units	141		
Subordinated units		15,955	35,634
Class B special units	2,532	181	
Total	265,511	199,915	155,454
Basic earnings per unit			
Income before changes in accounting principles and Enterprise GP interest	$ 0.97	$ 0.52	$ 0.62
Cumulative effect of changes in accounting principles	0.04		
Enterprise GP interest in net income	(0.14)	(0.10)	(0.07)
Limited partners' interest in net income	$ 0.87	$ 0.42	$ 0.55
DILUTED EARNINGS PER UNIT			
Numerator			
Income before changes in accounting principles and Enterprise GP interest	$ 257,480	$ 104,546	$ 95,500
Cumulative effect of changes in accounting principles	10,781		
Enterprise GP interest in net income	(37,108)	(20,729)	(10,663)
Limited partners' interest in net income	$ 231,153	$ 83,817	$ 84,837
Denominator			
Common units	262,838	183,779	119,820
Restricted common units	141		
Subordinated units		15,955	35,634
Class A special units		5,808	21,036
Class B special units	2,532	181	
Performance-based restricted units	14		
Series F2 convertible units	22		
Incremental option units	498	644	
Total	266,045	206,367	176,490
Diluted earnings per unit			
Income before changes in accounting principles and Enterprise GP interest	$ 0.97	$ 0.51	$ 0.54
Cumulative effect of changes in accounting principles	0.04		
Enterprise GP interest in net income	(0.14)	(0.10)	(0.06)
Limited partners' interest in net income	$ 0.87	$ 0.41	$ 0.48

14. RELATED PARTY TRANSACTIONS

The following table summarizes our related party transactions for the periods indicated:

	For Year Ended December 31,		
	2004	2003	2002
Revenues from consolidated operations			
EPCO and subsidiaries	$ 2,697	$ 4,241	$ 3,630
Shell	542,912	293,109	282,820
Unconsolidated affiliates	258,541	266,894	196,267
Total	$ 804,150	$ 564,244	$ 482,717
Operating costs and expenses			
EPCO and subsidiaries	$ 202,561	$ 149,626	$ 103,210
Shell	725,420	607,277	531,712
Unconsolidated affiliates	37,587	43,752	60,657
Total	$ 965,568	$ 800,655	$ 695,579
Selling, general and administrative expenses			
EPCO Administrative Services Agreement	$ 27,454	$ 27,518	$ 24,204
Other EPCO transactions	653	442	n/a
Total	$ 28,107	$ 27,960	$ 24,204

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of Enterprise GP are employees of EPCO, including Robert G. Phillips who is Chief Executive Officer and a director of Enterprise GP. The principal business activity of Enterprise GP is to act as our managing partner.

Mr. Duncan owns 50.4% of the voting stock of EPCO. The remaining shares of EPCO capital stock are held primarily by trusts for the benefit of members of Mr. Duncan's family. In addition, at December 31, 2004, EPCO and Dan Duncan LLC, together, owned 90.1% of the membership interests of Enterprise GP, which in turn owns a 2% general partner interest in us. In January 2005, an affiliate of EPCO, Enterprise GP Holdings L.P., acquired El Paso's 9.9% membership interest in Enterprise GP (see Note 21). As a result of this transaction, EPCO and its affiliates own 100% of Enterprise GP.

In addition, trust affiliates of EPCO, the beneficiaries of which are the shareholders of EPCO (the 1998 Trust and 2000 Trust), owned 11,387,615 of our common units at March 15, 2005. Collectively, Mr. Duncan, through his beneficial ownership of our common units held personally, by the 1998 and 2000 Trusts and through subsidiaries of EPCO, controlled 37.4% of our common units at March 15, 2005.

Our agreements with EPCO are not the result of arm's-length transactions, and there can be no assurance that any of the transactions provided for therein are effected on terms at least as favorable to the parties to such agreement as could have been obtained from unaffiliated third parties.

Administrative Services Agreement. As stated previously, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. Under the current terms of the Administrative Services Agreement, EPCO agrees to:

- employ the personnel necessary to manage our business and affairs (through Enterprise GP);
- employ the operating personnel involved in our business;
- allow us to participate as named insureds in EPCO's current insurance program with the costs being allocated among the parties on the basis set forth in the agreement;
- sublease to us certain equipment which it holds pursuant to operating leases for one dollar per year and to assign to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the cash lease payments associated with these assets.

Operating costs and expenses (as shown on our Statements of Consolidated Operations and Comprehensive Income) treat the retained lease-related payments made by EPCO on our behalf as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the partnership. As of December 31, 2004, the remaining retained leases were for a cogeneration unit and approximately 100 railcars. During 2004, we exercised our options to purchase an isomerization unit and related equipment at a cost of $17.8 million. Should we decide to exercise the purchase options associated with the remaining retained leases (which are also at fair value), an additional $2.3 million would be payable in 2008 and $3.1 million in 2016. In addition to retained lease expense, operating costs and expenses include compensation charges for EPCO's employees who operate our facilities.

Selling, general and administrative costs (as shown in our Statements of Consolidated Operations and Comprehensive Income) include the costs we pay EPCO for administrative support. Prior to January 1, 2004, our payments to EPCO and related non-cash expenses for administrative support were based on the following:

- We reimbursed EPCO for our share of the costs of certain of its employees in administrative positions that were active at the time of our initial public offering in July 1998 (the "pre-expansion" administrative personnel). This includes costs associated with equity-based awards granted to certain individuals within this group. Our obligation for reimbursing these costs was covered by the EPCO Administrative Service Fee. We paid $17.9 million and $16.6 million of such fees to EPCO during 2003 and 2002, respectively.

- To the extent that EPCO's actual cost of providing the pre-expansion administrative personnel exceeded the Administrative Service Fee charged us during a given year, we recorded a non-cash expense equal to the difference as a non-cash selling, general and administrative cost. The offset was recorded in Partners' Equity on the Consolidated Balance Sheets as a general contribution to the partnership. The actual amounts incurred by EPCO for providing these services did not materially exceed the capped amount for the year ended December 31, 2002. For the year ended December 31, 2003, we recorded $0.4 million in non-cash expense related to this excess.

- We also reimburse EPCO for all costs it incurs related to administrative personnel it hires in response to our expansion and new business activities. This includes costs attributable to equity-based awards granted to members of this group.

Effective January 1, 2004, the Administrative Services Agreement was amended to eliminate the fixed Administrative Services Fee and to provide that we reimburse EPCO for all costs related to administrative support regardless of whether the costs are related to pre-expansion or expansion personnel who work on our behalf.

On October 22, 2004, the Administrative Services Agreement was amended further to evidence our separateness from other persons and entities, to reflect a five-year license we granted for EPCO's use of service marks owned by us and to provide for reimbursement of EPCO's costs of discontinuing the use of those service marks over the term of the license. This amendment also provides that if EPCO and its affiliates are offered by a third party, or discover an opportunity to acquire from a third party, a business or assets that is or are in the same or similar line of business then being conducted by the Operating Partnership or in a line of business that would be a natural extension of any business then being conducted by the Operating Partnership (a "Business Opportunity"), EPCO shall promptly advise the Board of Directors of Enterprise GP of such Business Opportunity and offer such Business Opportunity to the Operating Partnership. If the Board of Directors of Enterprise GP does not advise EPCO within 10 days following the receipt of such notice that we wish to pursue such Business Opportunity, EPCO shall then be permitted to pursue such Business Opportunity. If the Board of Directors of Enterprise GP advises EPCO within such 10 day period that we want to pursue such Business Opportunity, EPCO shall not be permitted to pursue such Business Opportunity unless the Board of Directors of Enterprise GP subsequently advises EPCO that it has abandoned its pursuit of such Business Opportunity.

Other related party transactions with EPCO. The following is a summary of other significant related party transactions between EPCO and us, including those between EPCO and our unconsolidated affiliates.

- Prior to January 1, 2004, EPCO was the operator of our MTBE facility and Houston Ship Channel NGL import facility. During 2003 and 2002, we paid EPCO $0.8 million for such services. Such payments were terminated effective January 1, 2004.

- We have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products.

- In the normal course of business, we also buy from and sell to EPCO's Canadian affiliate certain NGL products.

We and Enterprise GP are separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO primarily depends on the cash distributions it receives as an equity owner in us to fund its other operations and to meet its debt obligations. For the years ended December 31, 2004, 2003 and 2002, EPCO received $173.7 million, $160.4 million and $146.6 million in quarterly cash distributions from us, respectively.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At March 15, 2005, Shell owned approximately 9.5% of our common units. In March 2005, we registered for resale Shell's 36,572,122 common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999. For additional information regarding this subsequent event, see Note 21. Shell sold its 30.0% interest in Enterprise GP to a subsidiary of EPCO in September 2003.

Shell is one of our largest customers. For the years ended December 31, 2004, 2003 and 2002, Shell accounted for 6.5%, 5.5% and 7.9%, respectively, of our consolidated revenues. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell. We also lease from Shell its 45.4% interest in one of our propylene fractionation facilities located in Mont Belvieu, Texas.

The most significant contract affecting our natural gas processing business is the Shell margin-band/keepwhole processing agreement, which grants us the right to process Shell's current and future production within state and federal waters of the Gulf of Mexico. The Shell processing agreement includes a life of lease dedication, which may extend the agreement well beyond its initial 20-year term ending in 2019.

We have also completed a number of business acquisitions and asset purchases involving Shell since 1999, including the acquisition of midstream energy assets located along the Gulf Coast for approximately $528.8 million in 1999; the purchase of the Lou-Tex Propylene pipeline for $100 million in 2000; and the acquisition of the Acadian Gas pipeline system in 2001 for $243.7 million.

Relationships with unconsolidated affiliates

Our investment in unconsolidated affiliates with industry partners is a vital component of our business strategy. These investments are a means by which we conduct our operations to align our interests with a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. The following summarizes significant related party transactions we have with our current unconsolidated affiliates:

- We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. For the years ended December 31, 2004, 2003 and 2002, revenues from Evangeline were $233.9 million, $212.7 million and $131.6 million, respectively. In addition, we have also furnished $11.1 million in letters of credit on behalf of Evangeline.

- We pay transportation fees to Dixie for propane movements on their system initiated by our NGL marketing activities. For the years ended December 31, 2004, 2003 and 2002, we paid Dixie $13.1 million, $11.3 million and $12.2 million, respectively, in such transportation fees.

- We pay Promix for the transportation, storage and fractionation of certain of our mixed NGL volumes. In addition, we sell natural gas to Promix for their fuel requirements. For the years ended December 31, 2004, 2003 and 2002, we paid Promix $23.2 million, $17.5 million and $18.4 million, respectively, for their services. Additionally, for the years ended December 31, 2004, 2003 and 2002, revenues from Promix for the purchase of natural gas were $18.6 million, $19.6 million and $12.7 million, respectively.

Prior to its becoming a consolidated subsidiary in March 2003, we paid EPIK for export services to load product cargoes for our NGL and petrochemical marketing customers. Also, prior to its becoming a consolidated subsidiary in September 2003, we sold high purity isobutane to BEF as a feedstock and purchased certain of BEF's by-products. We also received transportation fees for BEF's shipments of MTBE on our HSC pipeline and fractionation revenues for reprocessing mixed feedstock streams generated by BEF.

We enter into management agreements with some of our unconsolidated affiliates under which our unconsolidated affiliates pay us management fees for the operation and management of their assets. For the years ended December 31, 2004, 2003 and 2002, such fees approximated $2.1 million, $1.5 million and $1.4 million, respectively. Additionally, on occasion we pay for construction costs on behalf of our unconsolidated affiliates during the initial construction phase of their assets, and these amounts are settled by direct reimbursements for the amounts we are owed from our unconsolidated affiliates.

15. UNIT OPTION PLAN ACCOUNTING

During 1998, EPCO adopted its 1998 Long-Term Incentive Plan (the "1998 Plan"). Under this program, non-qualified incentive options to purchase a fixed number of our common units may be granted to EPCO's key employees who perform management, administrative or operational functions for us. The exercise price per unit, vesting and expiration terms, and rights to receive distributions on units granted are determined by EPCO for each grant agreement. EPCO purchases common units to fund its obligations under the 1998 Plan at fair value either in the open market or from us (in the form of newly issued common units or reissued treasury units).

We account for our share of the costs of these awards using the intrinsic value-based method in accordance with APB No. 25, "*Accounting for Stock Issued to Employees*." The exercise price of each option granted is equivalent to or greater than the market price of the unit at the date of grant. Accordingly, no compensation expense related to unit options has been recognized in our Statements of Consolidated Operations and Comprehensive Income for the periods presented. The option-related reimbursements (as described below) that we make to reimburse EPCO for its costs related to these awards are a component of "Cash distributions to partners" as shown in our Statements of Consolidated Partners' Equity.

When employees exercise unit options, we reimburse EPCO for the difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units awarded to the employee. Effective January 1, 2004, with the amendment of our Administrative Services Agreement, we became responsible for reimbursing EPCO for all the costs it incurs when unit options are exercised. Under the amended agreement, our payment to EPCO is in the form of an option-related reimbursement regardless of how the option liability is satisfied (i.e., through open market purchases or units acquired from EPCO affiliates or us). During 2004 and 2003, we made $3.8 million and $2.7 million, respectively, in option-related reimbursements to EPCO to meet our obligations under EPCO's 1998 Plan.

Prior to January 1, 2004, our responsibility for reimbursing EPCO for the cash outlay it incurred when these options were exercised was as follows:

- We reimbursed EPCO for the costs attributable to unit option awards granted to operations personnel it employed on our behalf.
- We reimbursed EPCO for the costs attributable to unit option awards granted to administrative and management personnel it hired in response to our expansion and business activities.
- We paid EPCO for our share of the costs attributable to unit option awards granted to certain of its employees in administrative and management positions that were active at the time of our initial public offering in July 1998 under one of two methods described as follows:
    - If EPCO purchased common units in open market to fund its obligation to any employee of this group, the cost was reimbursed by us through the Administrative Service Fees we paid EPCO. EPCO was responsible for the actual cost of such award when the option was exercised. To the extent that EPCO's total administrative expense incurred on our behalf (including the expense associated with equity-based awards satisfied through open market purchases) exceeded the annual Administrative Service Fee we paid to EPCO, such excess costs resulted in a non-cash charge to our earnings as a related-party expense and a corresponding increase in Partners' Equity recorded as a general contribution; or

- If EPCO requested us to provide units to satisfy its obligations to these employees, we reimbursed EPCO for its actual costs of such awards.

On July 1, 2005, we will adopt the provisions of *SFAS No. 123(R), "Share-Based Payment."* This accounting guidance, which is applicable for the first interim or annual reporting period beginning after June 15, 2005, replaces SFAS No. 123, "*Accounting for Stock-Based Compensation*" and supersedes APB No. 25, "*Accounting for Stock Issued to Employees*." For additional information regarding this recent accounting standard, see Note 2.

Summary of 1998 Plan activity

The information in the following table shows unit option activity for EPCO personnel who work on our behalf.

	Number of Units	Weighted-average Strike Price
Outstanding at January 1, 2002	2,201,640	$ 11.88
Granted	379,000	23.42
Exercised	(270,562)	4.98
Outstanding at December 31, 2002	2,310,078	14.57
Granted	35,000	22.26
Exercised	(372,078)	7.10
Forfeited	(35,000)	18.86
Outstanding at December 31, 2003	1,938,000	16.07
Granted	910,000	22.17
Exercised	(385,000)	12.79
Outstanding at December 31, 2004	2,463,000	$ 18.84
Options exercisable at:		
December 31, 2002	711,078	$ 7.83
December 31, 2003	509,000	$ 9.68
December 31, 2004	1,154,000	$ 14.65

The following table provides additional information regarding our unit options outstanding at December 31, 2004:

				Options Exercisable at December 31, 2004	
Range of Strike Prices	Options Outstanding at December 31, 2004	Weighted Average Remaining Contractual Life (in Years)	Weighted Average Strike Price	Number Exercisable at December 31, 2004	Weighted Average Strike Price
$7.75 - $9.00	224,000	4.75	$ 8.44	224,000	$ 8.44
$11.63 - $12.56	110,000	5.91	12.00	110,000	12.00
$15.93 - $17.63	755,000	6.11	16.16	750,000	16.15
$20.00 - $24.73	1,374,000	8.82	22.55	70,000	22.64
	2,463,000			1,154,000	

The weighted-average fair value of options granted during 2004, 2003 and 2002 was $2.26, $2.17 and $3.12 per option, respectively.

16. COMMITMENTS AND CONTINGENCIES

Redelivery commitments

We store and transport NGL, petrochemical and natural gas volumes for third parties under various processing, storage, transportation and similar agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. We are insured for any physical loss of such volumes due to catastrophic events. At December 31, 2004, NGL and petrochemical volumes aggregating 13.5 million barrels were due to be redelivered to their owners along with 18,038 BBtus of natural gas.

Commitments under equity compensation plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 14). This includes the costs associated with equity-based awards granted to these employees. At December 31, 2004, there were 2,463,000 options outstanding to purchase common units under EPCO's 1998 Plan that had been granted to employees for which we were responsible for reimbursing EPCO for the costs of such awards. The weighted-average strike price of the unit option awards granted was $18.84 per common unit. At December 31, 2004, 1,154,000 of these unit options were exercisable. An additional 374,000, 25,000 and 910,000 of these unit options will be exercisable in 2005, 2006 and 2008, respectively. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee. See Note 15 for additional information regarding our accounting for unit options.

Other commitments

The following table summarizes our various contractual obligations at December 31, 2004. A description of each type of contractual obligation follows.

	Payment or Settlement Due by Period						
Contractual Obligations	**Total**	**2005**	**2006**	**2007**	**2008**	**2009**	**Thereafter**
Scheduled maturities of long-term debt	$4,288,698	$ 15,000		$ 500,000		$ 821,000	$2,952,698
Operating lease obligations	$ 88,899	$ 15,012	$ 13,328	$ 12,294	$ 9,496	$ 5,418	$ 33,351
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 1,160,829	$ 165,120	$ 142,133	$ 142,133	$ 142,522	$ 142,133	$ 426,788
NGLs	$ 174,281	$ 42,664	$ 10,968	$ 10,968	$ 10,968	$ 10,968	$ 87,745
Petrochemicals	$ 1,791,983	$ 1,010,907	$ 667,288	$ 107,540	$ 6,248		
Other	$ 166,706	$ 41,706	$ 32,179	$ 30,092	$ 28,690	$ 18,155	$ 15,884
Underlying major volume commitments:							
Natural gas (in BBtus)	149,705	21,855	18,250	18,250	18,300	18,250	54,800
NGLs (in MBbls)	5,657	1,267	366	366	366	366	2,926
Petrochemicals (in MBbls)	27,294	15,559	10,126	1,520	89		
Service payment commitments	$ 7,580	$ 4,906	$ 2,038	$ 636			
Capital expenditure commitments	$ 69,288	$ 69,288					

Long-term debt-related commitments. We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. The preceding table shows our scheduled future maturities of long-term debt principal (including current maturities) for the periods indicated. See Note 9 for a description of these debt obligations and classification used for accounting purposes.

Operating lease commitments. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. The preceding table shows the minimum lease payment obligations under our third-party operating leases with terms in excess of one year for the periods indicated.

Our material agreements consist of operating leases, with original terms ranging from 5 to 24 years, for natural gas and NGL underground storage facilities. We generally have the option to renew these leases, under the terms of the agreements, for one or more renewal terms ranging from 2 to 10 years. In general, rent is determined by multiplying a storage quantity (typically in barrels) by a contractually stated price. Rental payments under our storage leases are escalated, as specified in the lease, to reflect increases in the market value of the storage capacity or to adjust for inflation. In general, contingent rental payments are assessed when our storage volumes exceed our storage allotment and are equal to the product of (i) a contractually stated price and (ii) the volume which exceeds our storage allotment.

Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. Under certain of our natural gas and NGL storage lease agreements, we are required to perform routine maintenance on the storage facility. In addition, certain leases give us the option to increase storage capacity or fund major leasehold improvements. Maintenance, repairs and minor renewals are charged to operations as incurred. We have not made any major leasehold improvements with regards to our natural gas and NGL underground storage facilities during the years ended December 31, 2004, 2003 or 2002.

The operating lease commitments shown in the preceding table exclude the non-cash related party expense associated with various equipment leases contributed to us by EPCO at our formation for which EPCO has retained the liability (the "retained leases"). The retained leases are accounted for as operating leases by EPCO. EPCO's minimum future rental payments under these leases are $2.1 million for each of the years 2005 through 2008, $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016.

EPCO has assigned to us the purchase options associated with the retained leases. During 2004 we purchased an isomerization unit and related equipment for $17.8 million pursuant to our purchase options, which prices approximated fair value. Should we decide to exercise all of the remaining purchase options associated with the retained leases (which are also at fair value), up to an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

Third-party lease and rental expense included in operating income for the years ended December 31, 2004, 2003 and 2002 was approximately $19.5 million, $17.8 million and $16.4 million, respectively.

Purchase obligations. We define purchase obligations as agreements to purchase goods or services that are enforceable and legally binding (unconditional) and that specify all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

- *Product purchase commitments.* We have long and short-term product purchase obligations for NGLs, petrochemicals and natural gas with several third-party suppliers. The purchase prices that we are generally obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. At December 31, 2004, we do not have any product purchase commitments with fixed or minimum pricing provisions having remaining terms in excess of one year. To the extent that variable price provisions exist in these contracts, our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2004 applied to future volume commitments.

- *Service contract commitments.* We have long and short-term commitments to pay third-party service providers for services such as maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our future payment obligations under these service contracts.

- *Capital expenditure commitments*. We have short-term payment obligations relating to capital projects we have initiated and are also responsible for our share of such obligations associated with capital projects of our unconsolidated affiliates. These commitments represent unconditional payment obligations that we or our unconsolidated affiliates have agreed to pay vendors for services rendered or products purchased. The preceding table shows these combined amounts for the periods indicated.

Litigation

We are sometimes named as a defendant in litigation relating to our normal business operations, including litigation related to various federal, state and local regulatory and environmental matters. Although we insure against various business risks, to the extent management believes it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of ordinary business activity. Management is not aware of any significant litigation, pending or threatened, that would have a significant adverse effect on our financial position or results of operations.

We own a facility that historically produced MTBE, a motor gasoline additive that enhances octane and is used in reformulated motor gasoline. We operated the facility, which is located within our Mont Belvieu complex. The production of MTBE was primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990. In recent years, MTBE has been detected in water supplies. The major source of ground water contamination appears to be leaks from underground storage tanks. As a result of environmental concerns, several states enacted legislation to ban or significantly limit the use of MTBE in motor gasoline within their jurisdictions. In addition, federal legislation has been drafted to ban MTBE and replace the oxygenate with renewable fuels such as ethanol.

A number of lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing MTBE, although generally such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary which owns the facility. It is possible, however, that MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

Performance Guaranty

In December 2004, our Independence Hub, LLC subsidiary entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement obligates Independence Hub, LLC (i) to construct an offshore platform production facility to process 850 MMcf/d of natural gas and condensate and (ii) to process certain natural gas and condensate production of the six producers following construction of the platform facility.

In conjunction with the Agreement, our Operating Partnership guaranteed the performance of its Independence Hub, LLC subsidiary under the Hub Agreement up to $397.5 million. In December 2004, 20% of this guaranteed amount was assumed by Cal Dive, our joint venture partner in the Independence Hub project. The remaining $318 million represents our share of the anticipated cost of the platform facility. This amount represents the cap on our Operating Partnership's potential obligation to the six producers for our share of the cost of constructing the platform in the very unlikely scenario where the six producers take over the construction of the platform facility. Our performance guarantee continues until the earlier to occur of (i) all of the guaranteed obligations of Independence Hub, LLC shall have been terminated or expired, or shall have been indefeasibly paid or otherwise performed or discharged in full, (ii) upon mutual written consent of our Operating Partnership and the producers or (iii) mechanical completion of the production facility. We expect that mechanical completion will occur on or about November 1, 2006; therefore, we anticipate that the performance guaranty will exist until at least this forecast date.

In accordance with FIN 45, we recorded the fair value of the performance guaranty using an expected present value approach. Given the remote probability that our Operating Partnership would be required to perform under the guaranty, we have estimated the fair value of the performance guaranty at approximately $1.2 million, which is a component of current and other long-term liabilities on our Consolidated Balance Sheet at December 31, 2004.

17. SUPPLEMENTAL CASH FLOW DISCLOSURE

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities; (ii) cash payments for interest and (iii) cash payments for federal and state income taxes for the periods indicated.

	For Year Ended December 31,		
	2004	2003	2002
(Increase) decrease in:			
Accounts and notes receivable	$ (453,904)	$ (54,388)	$ (127,365)
Inventories	(44,202)	49,932	(84,254)
Prepaid and other current assets	2,726	11,073	15,340
Long-term receivables	611		
Other assets	(6,684)	(226)	(3,322)
Increase (decrease) in:			
Accounts payable	110,497	(6,720)	23,901
Accrued gas payable	286,089	128,050	262,527
Accrued expenses	8,800	(16,677)	7,884
Accrued interest	(199)	15,012	5,369
Other current liabilities	6,534	(4,196)	(6,921)
Other liabilities	(3,993)	(972)	(504)
Net effect of changes in operating accounts	$ (93,725)	$ 120,888	$ 92,655
Cash payments for interest, net of $2,766, $1,595 and $1,083 capitalized in 2004, 2003 and 2002, respectively	$ 135,797	$ 112,712	$ 82,535
Cash payments for federal and state income taxes	$ 182	$ 453	n/a

During 2004, we completed several business combinations, primarily the GulfTerra Merger and our purchase of certain midstream energy assets located in South Texas from El Paso. See Note 4 for the preliminary purchase price allocations related to these transactions which include non-cash consideration for equity interests issued and the fair values of assets acquired and liabilities assumed. In addition, see Note 10 for information regarding changes in our partners' equity accounts as a result of the GulfTerra Merger transactions, including amounts associated with unit awards and Series F2 convertible units.

We incurred liabilities for construction in progress and property additions that had not been paid at December 31, 2004, 2003 and 2002 of $62.4 million, $9.1 million and $6.5 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows. The increase in such amounts at December 31, 2004 compared to December 31, 2003 is primarily due our acquisition of GulfTerra, which had several large offshore projects.

On certain of our capital projects, third parties may be obligated to reimburse us for capital expenditures. As a result of completing the GulfTerra Merger, the number of such arrangements has increased, particularly for projects involving pipeline construction and production well tie-ins. In November 2004, Tennessee Gas Pipeline reimbursed us $7 million for construction costs incurred for our Independence Trail pipeline project, which is reflected as a source of investing cash inflows under the caption "Contributions in aid of construction" on our Statements of Consolidated Cash Flows. In addition to this reimbursement, we received $1.9 million, $0.9 million and $4 million as contributions in aid of construction during 2004, 2003 and 2002, respectively.

During 2003, we completed several business acquisitions, made adjustments to the 2002 purchase price allocation of the Mid-America and Seminole acquisitions and consolidated entities that had not been previously accounted for using the equity method. During 2002, we completed $1.8 billion in business acquisitions, the most significant of which were the acquisition of interests in the Mid-America and Seminole pipelines from Williams and propylene fractionation and NGL and petrochemical storage assets from Diamond-Koch. These transactions and events over the last three years affected various balance sheet categories summarized as follows:

	For Year Ended December 31,		
	2004	2003	2002
Current assets	$ 216,335	$ 24,960	$ 53,287
Property, plant and equipment	4,806,941	131,452	1,507,243
Investments in unconsolidated affiliates	160,075	(57,172)	7,550
Intangible assets	744,353	4,057	92,356
Goodwill	376,770	880	73,691
Deferred tax asset			17,307
Other assets	26,881	3,208	2,699
Current liabilities	(233,864)	(32,140)	(17,747)
Long-term debt	(2,015,583)		(60,000)
Other liabilities	(47,880)	(6,063)	(90)
Minority interest	26,590	(31,834)	(55,569)
Total	$ 4,060,618	$ 37,348	$ 1,620,727

Additionally, we record various financial instruments relating to commodity positions and interest rate hedging activities at their respective fair values using mark-to-market accounting. These amounts for 2004 and 2003 were negligible; however, during 2002, we recognized a net $10.2 million in non-cash mark-to-market decreases in the fair value of these instruments primarily in our commodity financial instruments portfolio.

Net income for 2004 includes a gain on sale of assets of approximately $15.1 million related to the satisfaction of certain requirements of a sale agreement whereby a 50% interest in Cameron Highway was sold. Approximately $10.1 million of this gain was the non-cash recognition of a receivable that is due no later than December 31, 2006 while $5.0 million of the gain was associated with a cash payment received during the fourth quarter of 2004.

Cash and cash equivalents (as shown on our Statements of Consolidated Cash Flows) excludes restricted cash amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for our physical purchase of natural gas made on the NYMEX exchange. The restricted cash balance at December 31, 2004 and 2003 was $26.2 million and $13.9 million, respectively.

18. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings, fair values of certain debt instruments and cash flows resulting from changes in applicable interest rates or commodity prices. As a matter of policy, we do not use financial instruments for speculative (or “trading”) purposes.

We recognize financial instruments as assets and liabilities on our Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument’s gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings.

To qualify as a hedge, the item to be hedged must be exposed to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance regarding the implementation of this accounting standard. Since this guidance is still continuing, our conclusions about the application of SFAS No. 133 may be altered, which may result in adjustments being recorded in future periods as we adopt new FASB interpretations of this standard.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess the cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis models to forecast the expected impact of changes in interest rates on our future cash flows. Enterprise GP oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business climate.

Fair value hedges – Interest rate swaps. In January 2004, we entered into three interest rate swap agreements with an aggregate notional amount of $250 million in which we exchanged the payment of fixed rate interest on a portion of the principal outstanding under Senior Notes B and C for variable rate interest. During the fourth quarter of 2004, we entered into six additional interest rate swap agreements with an aggregate notional amount of $600 million related to a portion of the principal outstanding under Senior Notes G issued on October 4, 2004.

Hedged Fixed Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 6.3%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 4.9%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.4%	$600 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these nine interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These nine agreements have a combined notional amount of $850 million and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we pay the counterparty a variable interest rate based on six-month LIBOR rates (plus an applicable margin as defined in each swap agreement) and receive back from the counterparty a fixed interest rate payment based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period"). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

Total fair value of the interest rate swaps in effect at December 31, 2004 was a receivable of approximately $0.5 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statements of Consolidated Operations and Comprehensive Income for the year ended December 31, 2004 reflects a $9.1 million benefit from these swap agreements.

Cash flow hedges – Forward starting interest rate swaps. During the first nine months of 2004, we entered into eight forward starting interest rate swap transactions having an aggregate notional amount of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these transactions was to effectively hedge the underlying U.S. treasury rate related to our anticipated issuance of $2 billion in principal amount of fixed rate debt. On October 4, 2004, our Operating Partnership issued $2 billion of private debt securities under Senior Notes E, F, G and H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS No. 133.

In April 2004, we elected to terminate the initial four forward starting swaps in order to manage and maximize the value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. In September 2004, we settled the remaining four swaps resulting in an $85.1 million payment to the counterparties. The net gain of $19.4 million from these settlements will be reclassified from Accumulated Other Comprehensive Income to reduce interest expense over the life of the associated debt.

The following table shows the notional amount covered by each forward starting swap and the cash gain (loss) associated with each swap upon settlement (dollars in thousands):

Term of Anticipated Debt Offering (or Forecasted Transaction)	**Notional Amount of Debt covered by Forward Starting Swaps**	**Net Cash Received upon Settlement of Forward Starting Swaps**
3-year, fixed rate debt instrument	$ 500,000	$ 4,613
5-year, fixed rate debt instrument	500,000	7,213
10-year, fixed rate debt instrument	650,000	10,677
30-year, fixed rate debt instrument	350,000	(3,098)
Total	$ 2,000,000	$ 19,405

Commodity risk hedging program

The prices of natural gas, NGLs and petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with natural gas and NGLs, we may enter into commodity financial instruments. The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas or NGLs. The commodity financial instruments we utilize may be settled in cash or with another financial instrument. Historically, we have not hedged our exposure to risks associated with petrochemical products, including MTBE.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by Enterprise GP. We may enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Enterprise GP oversees the strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

At December 31, 2004, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of natural gas cash flow and fair value hedges. We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific exposure. When this occurs, we may enter into a new commodity financial instrument to reestablish the economic hedge to which the closed instrument relates.

We recorded $0.4 million of income related to our commodity hedging activities during 2004 and an expense of $0.6 million during 2003, which are included in our operating costs and expenses in the Statements of Consolidated Operations and Comprehensive Income.

During 2002, we recognized a loss of $51.3 million from our commodity hedging activities that was recorded as an increase in our operating costs and expenses. Beginning in late 2000 and extending through March 2002, a large number of our commodity hedging transactions were based on the historical relationship between natural gas and NGL prices. This type of hedging strategy utilized the forward sale of natural gas at a fixed price with the expected margin on the settlement of the position offsetting or mitigating changes in the anticipated margins on NGL marketing activities and the market values of our equity NGL production. Throughout 2001, this strategy proved very successful (as the price of natural gas declined relative to our fixed positions) and was responsible for most of the $101.3 million in commodity hedging income we recorded during 2001.

In late March 2002, the effectiveness of this strategy was reduced due to an unexpected rapid increase in natural gas prices whereby the loss in the value of our fixed-price natural gas financial instruments was not offset by increased natural gas processing margins. Due to the inherent uncertainty surrounding natural gas prices at the time, we decided that it was prudent to exit this strategy, and we did so by late April 2002. The increased ineffectiveness of this strategy is the primary reason for the $51.3 million in commodity hedging losses recorded during 2002.

We had a limited number of commodity financial instruments open at December 31, 2004 and 2003. The fair value of these open positions at December 31, 2004 and 2003 was an asset of $219 thousand and $4 thousand, respectively (both amounts based on market prices on these dates).

Effect of financial instruments on Accumulated Other Comprehensive Income (Loss)

The following table summarizes the effect of our cash flow hedging financial instruments on accumulated other comprehensive income (loss) since January 1, 2002.

		Interest Rate Fin. Instrs.		Accumulated
	Commodity Financial Instruments	Treasury Locks	Forward-Starting Interest Rate Swaps	Other Comprehensive Income (Loss) Balance
Balance, January 1, 2002		$ -		$ -
Change in fair value of treasury locks		(3,560)		(3,560)
Balance, December 31, 2002		(3,560)		(3,560)
Reclassification of change in fair value of treasury locks		3,560		3,560
Gain on settlement of treasury locks		5,354		5,354
Reclassification of gain on settlement of treasury locks to interest expense		(364)		(364)
Balance, December 31, 2003		4,990		4,990
Gain on settlement of forward-starting interest rate swaps			$ 104,531	104,531
Loss on settlement of forward-starting interest rate swaps			(85,126)	(85,126)
Change in fair value of commodity financial instrument	$ 1,434			1,434
Reclassification of gain on settlement of treasury locks to interest expense		(418)		(418)
Reclassification of gain on settlement of forward-starting swaps to interest expense			(857)	(857)
Balance, December 31, 2004	$ 1,434	$ 4,572	$ 18,548	$ 24,554

During 2005, we will reclassify $0.4 million and $3.6 million from Accumulated Other Comprehensive Income as a reduction in interest expense from our treasury locks and forward-starting interest rate swaps, respectively. In addition, in the first quarter of 2005, we will record an approximate $1.6 million gain into income from Accumulated Other Comprehensive Income related to a commodity cash flow hedge acquired in the GulfTerra Merger. This gain is primarily due to an increase in fair value from that recorded for the commodity cash flow hedge at December 31, 2004.

Fair value information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair value due to their short-term nature. The estimated fair value of our fixed rate debt is estimated based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable rate debt obligations reasonably approximate their fair values due to their variable interest rates. The fair values associated with our commodity and interest rate hedging financial instruments were developed using available market information and appropriate valuation techniques.

The following table summarizes the estimated fair values of our various financial instruments at December 31, 2004 and 2003:

	December 31, 2004		December 31, 2003	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 50,713	$ 50,713	$ 44,317	$ 44,317
Accounts receivable	1,083,536	1,083,536	462,545	462,545
Commodity financial instruments (1)	3,904	3,904	358	358
Interest rate hedging financial instruments(2)	505	505		
Financial liabilities:				
Accounts payable and accrued expenses	1,466,115	1,466,115	799,456	799,456
Fixed-rate debt (principal amount)	3,725,469	3,922,459	1,734,000	1,849,327
Variable-rate debt	563,229	563,229	410,000	410,000
Commodity financial instruments (1)	3,685	3,685	355	355

(1) Represent commodity financial instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

(2) Represent interest rate hedging financial instrument transactions that had not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

Counterparty risk

From time to time, we have credit risk with our counterparties in terms of settlement risk associated with financial instruments. On all transactions where we are exposed to credit risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral and we do not anticipate nonperformance by our counterparties.

19. SEGMENT INFORMATION

Business segments are components of a business about which separate financial information is available. The components are regularly evaluated by the CEO of Enterprise GP in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

As a result of the GulfTerra Merger (see Note 4), we have reorganized our business activities into four reportable business segments, as discussed below. Our business segments are generally organized and managed according to the type of services rendered and products produced and/or sold. We have revised our prior segment information in order to conform to the current business segment operations and presentation.

We have segregated our business activities into four reportable business segments: Offshore Pipelines & Services, Onshore Natural Gas Pipelines & Services, NGL Pipelines & Services, and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology or process employed) and products produced and/or sold, as applicable.

The Offshore Pipelines & Services business segment consists of (i) approximately 1,150 miles of offshore natural gas pipelines strategically located to serve production areas in some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 800 miles of Gulf of Mexico offshore crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico, which are included in our Offshore Pipelines & Services business segment.

The Onshore Natural Gas Pipelines & Services business segment consists of approximately 17,200 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. In addition, this segment includes two salt dome natural gas storage facilities located in Mississippi, which are strategically located to serve the

Northeast, Mid-Atlantic and Southeast domestic natural gas markets. This segment also includes leased natural gas storage facilities located in Texas and Louisiana.

The NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 12,775 miles and related storage facilities, which include our strategic Mid-America and Seminole NGL pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminaling operations.

The Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes various petrochemical pipeline systems.

The Other non-segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP and our underlying investment in this entity at December 31, 2003. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with Step One of the GulfTerra Merger. Our investment in GulfTerra GP was accounted for using the equity method until the GulfTerra Merger was completed on September 30, 2004. On that date, GulfTerra GP became a wholly owned consolidated subsidiary of ours. Since the historical equity earnings of GulfTerra GP were based on net income amounts allocated to it by GulfTerra, it is impractical for us to allocate the equity income we received during the periods presented to each of our new business segments. Therefore, we have segregated equity earnings from GulfTerra GP from our other segment results to aid in comparability between the periods presented.

We operate predominantly in the midstream energy sector which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, our results of operations, cash flows and financial condition may be affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. In general, 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.

Our profitability could be 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 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. 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 the 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 also adversely affect our results of operations, cash flows and financial position.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States. Most of our plant-based operations are located either along the western Gulf Coast in Texas, Louisiana and Mississippi or in New Mexico. Our natural gas, NGL and oil pipelines and related operations are in a number of regions of the United States including the Gulf of Mexico offshore Texas and Louisiana; the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and certain regions of the central and western United States. Our marketing activities are headquartered in Houston, Texas at our main office and service customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

We evaluate segment performance based on segment gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results.

We define total (or consolidated) segment gross operating margin as operating income before: (1) depreciation, depletion and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions.

Segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. For example, we use the Promix NGL fractionator to process a portion of the mixed NGLs extracted by our gas plants. Another example is our use of the Dixie pipeline to transport propane sold to customers through our NGL marketing activities. See Note 14 for additional information regarding our related party relationships with unconsolidated affiliates.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and segment assets is construction-in-progress. Segment assets represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction generally do not contribute to segment gross operating margin, these assets are excluded from the business segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to each segment based on the classification of the assets to which they relate.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	Year Ended December 31,		
	2004	**2003**	**2002**
Revenues [1]	$ 8,321,202	$ 5,346,431	$ 3,584,783
Less operating costs and expenses [1]	(7,904,336)	(5,046,777)	(3,382,839)
Add: Equity in income (loss) of unconsolidated affiliates [1]	52,787	(13,960)	35,253
Depreciation and amortization in operating costs and expenses [2]	193,734	115,643	86,028
Retained lease expense, net in operating expenses allocable to us and minority interest [3]	7,705	9,094	9,125
Gain on sale of assets in operating costs and expenses [2]	(15,901)	(16)	(1)
Total segment gross operating margin	$ 655,191	$ 410,415	$ 332,349

(1) These amounts are taken from our Statements of Consolidated Operations and Comprehensive Income.
(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.
(3) These non-cash expenses represent the value of the operating leases contributed by EPCO to us for which EPCO has retained the cash payment obligation (i.e., the "retained leases"). The value of the retained leases contributed directly to us is shown on our Statements of Consolidated Cash Flows under the line item titled "Operating lease expense paid by EPCO." That portion of the value contributed by a minority interest holder is a component of "Contributions from minority interests" as shown in the financing activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our measurement of total segment gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows:

	Year Ended December 31,		
	2004	2003	2002
Total segment gross operating margin	$ 655,191	$ 410,415	$ 332,349
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation and amortization in operating costs and expenses	(193,734)	(115,643)	(86,028)
Retained lease expense, net in operating costs and expenses	(7,705)	(9,094)	(9,125)
Gain on sale of assets in operating costs and expenses	15,901	16	1
Selling, general and administrative costs	(46,659)	(37,590)	(42,890)
Consolidated operating income	422,994	248,104	194,307
Other expense	(153,625)	(134,406)	(94,226)
Income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 269,369	$ 113,698	$ 100,081

Information by segment, together with reconciliations to the consolidated totals, is presented in the following table:

	Business Segments						
	Offshore Pipeline & Services	Onshore Nat. Gas Pipelines & Services	NGL Pipelines & Services	Petrochem. Services	Non-Segmt. Other	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:							
Year ended December 31, 2004	$ 32,168	$ 541,529	$ 5,553,895	$ 1,389,460			$ 7,517,052
Year ended December 31, 2003		344,611	3,654,596	782,999			4,782,206
Year ended December 31, 2002		295,709	2,246,266	560,091			3,102,066
Revenues from related parties:							
Year ended December 31, 2004	535	253,194	534,279	16,142			804,150
Year ended December 31, 2003		227,973	325,358	10,894			564,225
Year ended December 31, 2002		146,062	311,525	25,130			482,717
Intersegment and intrasegment revenues:							
Year ended December 31, 2004	358	21,436	2,077,871	249,758		$ (2,349,423)	-
Year ended December 31, 2003		3,975	1,143,595	186,672		(1,334,242)	-
Year ended December 31, 2002		2,271	757,311	151,880		(911,462)	-
Total revenues:							
Year ended December 31, 2004	33,061	816,159	8,166,045	1,655,360		(2,349,423)	8,321,202
Year ended December 31, 2003		576,559	5,123,549	980,565		(1,334,242)	5,346,431
Year ended December 31, 2002		444,042	3,315,102	737,101		(911,462)	3,584,783
Equity in income (loss) in unconsolidated affiliates:							
Year ended December 31, 2004	8,859	772	9,898	1,233	$ 32,025		52,787
Year ended December 31, 2003	5,561	131	7,842	(27,441)	(53)		(13,960)
Year ended December 31, 2002	10,534	(58)	15,392	9,385			35,253
Gross operating margin by individual business segment and in total:							
Year ended December 31, 2004	36,478	90,977	374,196	121,515	32,025		655,191
Year ended December 31, 2003	5,561	18,345	310,677	75,885	(53)		410,415
Year ended December 31, 2002	10,535	22,110	181,928	117,776			332,349
Segment assets:							
At December 31, 2004	648,181	3,729,650	2,753,934	469,327		230,375	7,831,467
At December 31, 2003		220,922	2,183,485	484,666		74,432	2,963,505
Investments in and advances to unconsolidated affiliates:							
At December 31, 2004	319,463	5,251	173,883	20,567			519,164
At December 31, 2003	127,605	2,519	190,682	22,006	424,947		767,759
Intangible Assets:							
At December 31, 2004	200,047	425,806	303,459	51,289			980,601
At December 31, 2003			215,072	53,821			268,893
Goodwill:							
At December 31, 2004	62,348	290,397	32,763	73,690			459,198
At December 31, 2003			8,737	73,690			82,427

In general, our historical operating results and/or financial position have been affected by numerous acquisitions since 2002. Our most significant transaction to date was the GulfTerra Merger, which was completed on September 30, 2004. The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. The GulfTerra Merger and our other acquisitions were accounted for using purchase accounting; therefore, the operating results of these acquired entities are included in our financial results prospectively from their respective purchase dates.

20. CONDENSED FINANCIAL INFORMATION OF OPERATING PARTNERSHIP

The Operating Partnership and its subsidiaries conduct substantially all of our business. Currently, we have no independent operations and no material assets outside of those of the Operating Partnership. In December 2003, we restructured Enterprise GP's ownership interest in us and the Operating Partnership from a 1% ownership interest in us and 1.0101% ownership in the Operating Partnership to a 2% ownership in us. As a result, our effective ownership in the Operating Partnership increased from 98.9899% to 100%. For additional information regarding our capital structure, see Note 10.

At December 31, 2004, the Operating Partnership had $3.7 billion in outstanding debt securities represented by its Senior Notes A, B, C, D, E, F, G and H. We act as guarantor of all our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes and the remaining amounts outstanding under GulfTerra's senior and senior subordinated notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. Our guarantee of these debt obligations is full and unconditional. For additional information regarding our consolidated debt obligations, see Note 9.

The number and dollar amounts of reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. The primary reconciling items between the consolidated balance of the Operating Partnership and our consolidated balance sheet are treasury units we own directly and minority interest. The differences in consolidated net income are primarily dividends recognized by the 1999 Trust (which are eliminated in consolidation) and minority interest.

The following table shows condensed consolidated balance sheet data for the Operating Partnership at the dates indicated:

	December 31,	
	2004	**2003**
ASSETS		
Current assets	$ 1,425,574	$ 687,530
Property, plant and equipment, net	7,831,467	2,963,505
Investments in and advances to unconsolidated affiliates, net	519,164	767,759
Intangible assets, net	980,601	268,893
Goodwill	459,198	82,427
Deferred tax asset	6,467	10,437
Long-term receivables	14,931	
Other assets	43,208	22,610
Total	$ 11,280,610	$ 4,803,161
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 1,582,911	$ 1,093,747
Long-term debt	4,266,236	1,899,548
Other long-term liabilities	63,521	14,081
Minority interest	73,858	89,216
Partners' equity	5,294,084	1,706,569
Total	$ 11,280,610	$ 4,803,161
Total Operating Partnership debt obligations guaranteed by us	$ 4,267,229	$ 2,114,000

The following table shows condensed consolidated statements of operations data for the Operating Partnership for the periods indicated:

	For Year Ended December 31,		
	2004	2003	2002
Revenues	$ 8,321,202	$ 5,346,431	$ 3,584,783
Costs and expenses	7,946,816	5,083,701	3,425,503
Equity in income (loss) of unconsolidated affiliates	52,787	(13,960)	35,253
Operating income	427,173	248,770	194,533
Other income (expense)	(153,251)	(133,798)	(93,810)
Income before provision for income taxes, minority interest and changes in accounting principles	273,922	114,972	100,723
Provision for income taxes	(3,761)	(5,293)	(1,634)
Income before minority interest and changes in accounting principles	270,161	109,679	99,089
Minority interest	(8,072)	(3,095)	(2,137)
Income before changes in accounting principles	262,089	106,584	96,952
Cumulative effect of changes in accounting principles	10,781		
Net income	$ 272,870	$ 106,584	$ 96,952

21. SUBSEQUENT EVENTS

January 2005 acquisition of El Paso's interests in the Company and Enterprise GP by affiliates of EPCO

In January 2005, an affiliate of EPCO, acquired El Paso's 9.9% membership interest in Enterprise GP and 13,454,499 of our common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and affiliates own 100% of the membership interests of Enterprise GP and approximately 38.3% of our total common units outstanding. El Paso no longer owns any interest in us or Enterprise GP.

February 2005 equity offering

In February 2005, we sold 17,250,000 common units (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005) to the public at an offering price of $27.05 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $9.1 million, were approximately $456.5 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $19.7 million. The net proceeds from this offering, including Enterprise GP's proportionate net capital contribution, were used to repay our 364-Day Acquisition Credit Facility, to temporarily reduce indebtedness outstanding under our Multi-Year Revolving Credit Facility and for general partnership purposes.

February 2005 private senior notes offering

On February 15, 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a Rule 144A private placement offering, comprised of $250 million in principal amount of 10-year senior unsecured notes and $250 million in principal amount of 30-year senior unsecured notes. The 10-year notes ("Senior Notes I") were issued at 99.379% of their principal amount and have fixed-rate interest of 5.00% and a maturity date of March 1, 2015. The 30-year notes ("Senior Note J") were issued at 98.691% of their principal amount and have fixed-rate interest of 5.75% and a maturity date of March 1, 2035. The Operating Partnership used the net proceeds from the issuance of Senior Notes I and J to repay $350 million of indebtedness outstanding under Senior Notes A which was on March 15, 2005 and the remaining proceeds for general partnership purposes, including the temporary repayment of indebtedness outstanding under the Multi-Year Revolving Credit Facility.

March 2005 universal shelf registration statement

In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 36,572,122 common units currently owned by Shell and 4,427,878 common units that had been sold by Shell to Kayne Anderson MLP Investment Company in December 2004. We are obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999.

Non-Public Investigation by the Bureau of Competition of the Federal Trade Commission

On February 24, 2005, an affiliate of EPCO, Enterprise GP Holdings, L.P., acquired TEPPCO GP from Duke Energy Field Services, LLC. TEPPCO GP owns a 2% general partner interest in and is the general partner of TEPPCO. On March 11, 2005, the Bureau of Competition of the Federal Trade Commission delivered written notice to Enterprise GP Holdings, L.P.'s legal advisor that it was conducting a non-public investigation to determine whether Enterprise GP Holdings' acquisition of TEPPCO GP may substantially lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with Enterprise GP Holdings' purchase of TEPPCO GP. EPCO and its affiliates may receive similar inquiries from other regulatory authorities. EPCO and its affiliates, including us, intend to cooperate fully with any such investigations and inquiries.

22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table contains selected quarterly financial data for 2004 and 2003 (dollars in thousands, except per unit amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
For the Year Ended December 31, 2004:				
Revenues	$ 1,704,890	$ 1,713,346	$ 2,040,271	$ 2,862,695 (1)
Operating income	87,314	65,051	93,209	175,284 (1)
Income before changes in accounting principles	51,528	33,075	57,523	115,354 (1)
Net income	58,541	33,075	61,291	115,354 (1)
Income per unit before changes in accounting principles:				
Basic	$ 0.24	$ 0.11	$ 0.20	$ 0.28
Diluted	$ 0.23	$ 0.11	$ 0.20	$ 0.28
Net income per unit:				
Basic	$ 0.24	$ 0.11	$ 0.21	$ 0.28
Diluted	$ 0.23	$ 0.11	$ 0.21	$ 0.28
For the Year Ended December 31, 2003:				
Revenues	$ 1,481,586	$ 1,210,659	$ 1,234,780	$1,419,406
Operating income	85,032	66,348	30,622 (2)	66,102
Net income (loss)	40,505	33,105	(3,261) (2)	34,197
Net income per unit:				
Basic	$ 0.20	$ 0.15	$ (0.04) (2)	$ 0.13
Diluted	$ 0.19	$ 0.14	$ (0.04) (2)	$ 0.13

(1) Revenues, operating income, income before changes in accounting principles and net income increased as a result of the GulfTerra Merger, which was completed on September 30, 2004. Net income for the fourth quarter of 2004 also includes a gain on sale of assets of approximately $15.1 million related to the satisfaction of certain requirements of a sale agreement whereby a 50% interest in Cameron Highway was sold. Approximately $10.1 million of this gain was the non-cash recognition of a receivable that is due no later than December 31, 2006 while $5.0 million of the gain was associated with a cash payment received during the fourth quarter of 2004.

(2) Equity earnings from BEF for the third quarter of 2003 include a $22.5 million asset impairment charge. This non-cash charge resulted in our posting a net loss for the quarter.

MARKET AND CASH DISTRIBUTION HISTORY FOR COMMON UNITS AND RELATED UNITHOLDER MATTERS

Market information and cash distributions. Our common units are traded on the NYSE under the symbol "EPD." As of March 1, 2005, there were an estimated 852 unitholders of record of our common units. The following table sets forth, for the periods indicated, the high and low sales price ranges for the common units, as reported on the NYSE Composite Transaction Tape, and the amount, record date and payment date of the quarterly cash distributions paid per common unit.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2003					
1st Quarter	$21.000	$17.850	$0.3625	Apr. 30, 2003	May 12, 2003
2nd Quarter	$24.690	$20.620	$0.3625	Jul. 31, 2003	Aug. 11, 2003
3rd Quarter	$24.100	$20.250	$0.3725	Oct. 31, 2003	Nov. 12, 2003
4th Quarter	$24.980	$20.760	$0.3725	Jan. 30, 2004	Feb. 11, 2004
2004					
1st Quarter	$24.720	$21.750	$0.3725	Apr. 30, 2004	May 12, 2004
2nd Quarter	$23.840	$20.000	$0.3725	Jul. 30, 2004	Aug. 11, 2004
3rd Quarter	$23.700	$20.190	$0.3950	Oct. 29, 2004	Nov. 5, 2004
4th Quarter	$25.990	$22.730	$0.4000	Jan. 31, 2005	Feb. 14, 2005

The quarterly cash distribution amounts shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., payments to our limited partners) occur within 45 days after the end of such quarter. Although the payment of cash dividends is not guaranteed, we expect to continue to pay comparable cash distributions in the future. We agreed in the merger agreement with GulfTerra, subject to the terms of our partnership agreement, to increase the quarterly cash distribution for the quarterly distribution date immediately following the closing of the merger to at least $0.395 per unit, or $1.58 per common unit on an annualized basis. The increase in our quarterly cash distribution commenced with the distribution paid with respect to the third quarter of 2004. On January 19, 2005, we announced that our quarterly cash distribution with respect to the fourth quarter of 2004 was raised to $0.40 per unit, or $1.60 per common unit on an annualized basis.

We expect to fund our quarterly cash distributions to partners primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, please read "*Our Liquidity and Capital Resources*" on page 30 of this annual report.

Recent sales of unregistered securities. There were no unreported sales of unregistered equity securities during 2004. On December 17, 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO, for $100 million in a private transaction that was exempt from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof. On July 29, 2004, we requested that our common unitholders approve the conversion of all of the non-voting Class B special units into voting common units on a one-for-one basis at a special meeting that was held on July 29, 2004, to approve our merger with GulfTerra. On this date, our common unitholders approved the conversion and our 4,413,549 Class B special units converted to an equal number of common units.

Common Units Authorized for Issuance Under Equity Compensation Plan. Please read the information included under Item 12 of our 2004 Form 10-K filed with the Securities and Exchange Commission, regarding securities authorized for issuance under equity compensation plans.

Repurchases of Common Units. We did not repurchase any of our common units during 2004. Previously, on December 23, 1998, we announced a common units repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the two-for-one unit split in May 2002). As of March 1, 2005, we and our affiliates are authorized to repurchase up to 618,400 additional common units under this repurchase program. Common units repurchased under this program are classified as treasury units.

EMPLOYEES

We do not have any employees. EPCO employs most of the persons necessary for the operation of our business. At December 31, 2004, EPCO had approximately 2,345 employees involved in the management and operations of our business, none of whom were members of a union. We fully reimburse EPCO for the costs of all 2,345 employees. In addition to EPCO employees, we have engaged approximately 261 contract maintenance and other personnel who support our operations.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND RISK FACTORS

This annual report contains various forward-looking statements and information that are based on our beliefs and those of Enterprise GP, our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "intend," "could," "believe," "may" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor Enterprise GP can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please read the section titled "*Risk Factors*" included under Item 7 in our 2004 Form 10-K filed with the Securities and Exchange Commission.

NEW YORK STOCK EXCHANGE COMPLIANCE

On November 30, 2004 we submitted to the New York Stock Exchange our CEO Certification, as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual. We also filed the Sarbanes-Oxley Section 302 certifications of our Chief Executive Officer and our Chief Financial Officer as Exhibits 31.1 and 31.2, respectively, to our Annual Report on Form 10-K for the year ended December 31, 2004, as filed with the Securities and Exchange Commission on March 15, 2005.

ENTERPRISE PRODUCTS PARTNERS L.P.
SUPPLEMENTAL INFORMATION – RECONCILIATION OF GAAP FINANCIAL STATEMENTS TO NON-GAAP FINANCIAL MEASURES

	For the Year Ended December 31,				
	2004	2003	2002	2001	2000
Reconciliation of Non-GAAP "EBITDA" to GAAP "Net Income" and GAAP "Operating Activities Cash Flows"					
Net Income	$268,261	$104,546	$95,500	$242,178	$220,506
Adjustments to reconcile EBITDA to Net Income:					
Interest expense	155,740	140,806	101,580	52,456	33,329
Provision for income taxes	3,761	5,293	1,634		
Depreciation and amortization (excluding amortization component in interest expense)	195,384	115,801	86,106	51,116	37,310
EBITDA	$623,146	$366,446	$284,820	$345,750	$291,145
Reconciliation of "EBITDA" to "Operating Activities Cash Flows":					
Interest expense	(155,740)	(140,806)	(101,580)	(52,456)	(33,329)
Amortization in interest expense	3,503	12,634	8,819	787	3,735
Provision for income taxes	(3,761)	(5,293)	(1,634)		
Equity in (income) loss of unconsolidated affiliates	(52,787)	13,960	(35,253)	(25,358)	(24,119)
Distributions from unconsolidated affiliates	68,027	31,882	57,662	45,054	37,267
Loss (gain) on sale of long-lived asset	(15,901)	(16)	(1)	(390)	2,270
Provision for impairment of asset	4,114	1,200			
Operating lease expense paid by EPCO (excluding minority interest portion)	7,705	9,010	9,033	10,309	10,537
Other expenses paid by EPCO (excluding minority interest portion)	-	436			
Minority interest	8,128	3,859	2,947	2,472	2,253
Deferred income tax expense	9,608	10,534	2,080		
Changes in fair market value of financial instruments	5	(29)	10,213	(5,697)	
Increase in restricted cash used for operating activities	(12,305)	(5,100)	(2,999)	(5,752)	
Net effect of changes in operating accounts	(93,725)	120,888	92,655	(37,143)	71,111
Cumulative effect of changes in accounting principles	(10,781)				
Operating Activities Cash Flows	$379,236	$419,605	$326,762	$277,576	$360,870
Reconciliation of Non-GAAP "Distributable Cash Flow" to GAAP "Net Income" and GAAP "Operating Activities Cash Flows"					
Net Income	$268,261	$104,546	$95,500	$242,178	$220,506
Adjustments to reconcile Distributable Cash Flow to Net Income:					
Operating lease expense paid by EPCO (excluding minority interest portion)	7,705	9,010	9,033	10,309	10,537
Operating lease expense paid by EPCO (minority interest portion)		84	92	105	107
Other expenses paid by EPCO (excluding minority interest portion)		436			
Other expense paid by EPCO (minority interest portion)		6			
Cumulative effect of changes in accounting principles, excluding minority interest portion	(8,443)				
Equity in (income) loss of unconsolidated affiliates	(52,787)	13,960	(35,253)	(25,358)	(24,119)
Distributions from unconsolidated affiliates	68,027	31,882	57,662	45,054	37,267
Deferred income tax expense	9,608	10,534	2,080		
Provision for impairment of long-lived asset	4,114	1,200			
Loss (gain) on sale of assets	(15,901)	(16)	(1)	(390)	2,270
Proceeds from sale of assets	6,882	212	165	568	92
Changes in fair market value of financial instruments	5	(29)	10,213	(5,697)	
Depreciation and amortization	198,887	128,435	94,925	51,903	41,045
Sustaining capital expenditures	(37,315)	(20,313)	(7,201)	(5,994)	(3,548)
Collection of notes receivable from unconsolidated affiliates					6,519
Settlement of forward-starting interest rate swaps	19,405				
Non-cash reduction in reserves established for Enron bankruptcy recorded as a component of changes in operating accounts		(2,073)		(11,246)	
El Paso transition support payments	4,500				
GulfTerra distributable cash flow for third quarter of 2004	68,402				
General Partner minority interest in net income		892	979	2,472	2,253
Distributable Cash Flow	$541,350	$278,766	$228,194	$303,904	$292,929
Reconciliation of "Distributable Cash Flow" to "Operating Activities Cash Flows"					
Minority interest portion of cumulative effect of changes in accounting principles	(2,338)				
Sustaining capital expenditures	37,315	20,313	7,201	5,994	3,548
Proceeds from sale of assets	(6,882)	(212)	(165)	(568)	(92)
GulfTerra distributable cash flow for third quarter of 2004	(68,402)				
Minority interest in earnings not included in calculation of Distributable Cash Flow	8,128	2,967	1,968		
Minority interest of General Partner in subsidiary's allocation of leases and other expenses paid by EPCO		(90)	(92)	(105)	(107)
Settlement of forward-starting interest rate swaps	(19,405)				
Non-cash reduction in reserves established for Enron bankruptcy recorded as a component of changes in operating accounts		2,073		11,246	
El Paso transition support payments	(4,500)				
Collection of notes receivable from unconsolidated affiliates recorded as a component of financing activities cash flows					(6,519)
Increase in restricted cash	(12,305)	(5,100)	(2,999)	(5,752)	
Net effect of changes in operating accounts	(93,725)	120,888	92,655	(37,143)	71,111
Operating Activities Cash Flows	$379,236	$419,605	$326,762	$277,576	$360,870

DIRECTORS AND OFFICERS OF ENTERPRISE PRODUCTS GP, LLC

Directors

O.S. Andras [1]
Vice Chairman,
Enterprise Products GP, LLC

E. William Barnett [2], [3]
Former Managing Partner,
Baker Botts, L.L.P.

Dan L. Duncan [1], [4]
Chairman,
Enterprise Products GP, LLC

Robert G. Phillips [1]
President and Chief Executive Officer,
Enterprise Products GP, LLC

W. Matt Ralls [2], [3]
Senior Vice President and Chief Financial Officer,
GlobalSantaFe

Richard S. Snell [2], [3]
Partner,
Thompson Knight, LLP

Officers of Enterprise Products GP, LLC, in addition to Directors

Richard H. Bachmann [1]
Executive Vice President,
Chief Legal Officer and Secretary

Michael A. Creel [1]
Executive Vice President and
Chief Financial Officer

James H. Lytal [1]
Executive Vice President

A.J. "Jim" Teague [1]
Executive Vice President

Lynn L. Bourdon, III [1]
Senior Vice President

James A. Cisarik [1]
Senior Vice President

James M. Collingsworth [1]
Senior Vice President

Charles E. Crain [1]
Senior Vice President

W. Randall Fowler [1]
Senior Vice President and Treasurer

Bart H. Heijermans [1]
Senior Vice President

Richard A. Hoover [1]
Senior Vice President

Michael J. Knesek [1]
Senior Vice President, Controller and
Principal Accounting Officer

Joel D. Moxley [1]
Senior Vice President

William Ordemann [1]
Senior Vice President

Gil H. Radtke [1]
Senior Vice President

Charles M. Brabson
Vice President

Gerald R. Cardillo
Vice President

Frank A. Chapman
Vice President

Vincent J. Di Cosimo
Vice President

Paul G. Flynn
Vice President and Chief Information Officer

James D. Gernentz
Vice President

Theodore Helfgott, Ph. D.
Vice President, Environmental

Terrance L. Hurlbert
Vice President

William G. Manias
Vice President

James N. McGrew
Vice President

Rudy A. Nix
Vice President

Daniel P. Olsen
Vice President

Angela M. Raguso
Vice President

Gregory W. Watkins
Vice President

A. Monty Wells
Vice President

Thomas M. Zulim
Vice President, Human Resources

Stephanie C. Hildebrandt
Assistant Secretary

John E. Smith
Assistant Secretary

Patricia A. Totten
Assistant Secretary

[1] Executive Officer
[2] Member of Audit and Conflicts Committee
[3] Member of Governance Committee
[4] Non-voting Director

Glossary

The following abbreviations, acronyms or terms used in this annual report are defined below:

Acadian Gas	Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001
Administrative Services Agreement	Second Amended and Restated Administrative Services Agreement, effective as of October 1, 2004, among EPCO, the Company, the Operating Partnership, the general partner of the OLP and our Enterprise GP (formerly, the "EPCO Agreement")
Anadarko	Anadarko Petroleum Corporation, its subsidiaries and affiliates
APB	Refers to opinions or statements issued the Accounting Principles Board
ARB	Refers to Accounting Research Bulletins
ARO	Asset retirement obligations
BBtus	Billion British thermal units, a measure of heating value
BBtus/d	Billion British thermal units per day, a measure of heating value
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
BEF	Belvieu Environmental Fuels GP, LLC and Belvieu Environmental Fuels, L.P., collectively
Belle Rose	Belle Rose NGL Pipeline LLC, an equity investment
BP	BP PLC, its subsidiaries and affiliates
BRF	Baton Rouge Fractionators LLC, an equity investment
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity investment
Cal Dive	Cal Dive International, Inc., its subsidiaries and affiliates
Cameron Highway	Cameron Highway Oil Pipeline Company, an equity investment
CEO	Chief Executive Officer
CFO	Chief Financial Officer
ChevronTexaco	ChevronTexaco Corp., its subsidiaries and affiliates
CMAI	Chemical Market Associates, Inc.
Cogeneration	Cogeneration is the simultaneous production of electricity and heat using a single fuel such as natural gas.
Company	Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Operating Partnership (also referred to as "Enterprise")
ConocoPhillips	ConocoPhillips Petroleum Company, its subsidiaries and affiliates
Coyote	Coyote Gas Treating, LLC, an equity investment
CPG	Cents per gallon
Deepwater	Deepwater refers to oil and gas production areas located at depths of 1,000 feet or more such as those found in the Gulf of Mexico.
Deepwater Gateway	Deepwater Gateway, L.L.C., an equity investment
Devon	Devon Energy Corporation, its affiliates and subsidiaries
Diamond-Koch	Refers to common affiliates of both Valero Energy Corporation and Koch Industries, Inc.
Dixie	Dixie Pipeline Company, an equity investment
Dominion	Dominion Resources, Inc., its subsidiaries and affiliates
DRIP	Distribution Reinvestment Plan
EITF	Emerging Issues Task Force
El Paso	El Paso Corporation and its affiliates
Enterprise	Enterprise Products Partners L.P. and its consolidated subsidiaries, including the Operating Partnership
Enterprise GP	Enterprise Products GP, LLC, the general partner of the Company
EPCO	EPCO, Inc. (formerly Enterprise Products Company), an affiliate of the Company and our ultimate parent company
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the "Operating Partnership")

Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity investment
ExxonMobil	Exxon Mobil Corporation, its subsidiaries and affiliates
FASB	Financial Accounting Standards Board
Feedstock	A raw material required for an industrial process such as in petrochemical manufacturing
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
Forward sales contracts	The sale of a commodity or other product in a current period for delivery in a future period.
FTC	U.S. Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States of America
GulfTerra	Enterprise GTM Holdings L.P., formerly named GulfTerra Energy Partners, L.P.
GulfTerra GP	Enterprise GTMGP, L.L.C., formerly named GulfTerra Energy Company, L.L.C., the general partner of GulfTerra
GulfTerra Merger	Refers to Step One, Step Two and Step Three of the merger of GulfTerra with a wholly owned subsidiary of the Company and the various transactions related thereto. Please read Note 3 of the Notes to Consolidated Financial Statements for a description of Step One, Step Two and Step Three of the GulfTerra Merger.
HSC	Denotes our Houston Ship Channel pipeline system
Isomerization	For a discussion of the isomerization process, please read "*The Company's Operations—Petrochemical Services—Butane Isomerization*" beginning on page 15 of this annual report.
Kerr-McGee	Kerr-McGee Corporation, its subsidiaries and affiliates
Koch	Koch Industries, Inc. , its subsidiaries and affiliates
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity investment
LIBOR	London interbank offered rate
LCM	Lower of average cost or market
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
Mid-America	Mid-America Pipeline Company, LLC
Midstream Energy Assets	The intermediate segments of the energy industry downstream of oil and gas production and upstream of end user consumption. These segments provide services to producers and consumers of energy. These services generally include but are not limited to natural gas gathering, processing and wholesale marketing and NGL fractionation, transportation and storage.
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MMBtus	Million British thermal units, a measure of heating value
Mont Belvieu	Mont Belvieu, Texas
Moody's	Moody's Investors Service
MTBE	Methyl tertiary butyl ether
Natural gas processing	For a discussion of our natural gas processing business, please read "*The Company's Operations—Natural Gas Processing and related NGL marketing activities*" beginning on page 11 of this annual report.
Nemo	Nemo Gathering Company, LLC, an equity investment
Neptune	Neptune Pipeline Company, L.L.C., an equity investment
NGL or NGLs	Refers to natural gas liquid(s), which are used by the petrochemical and refining industries to produce plastics, motor gasoline and other industrial and consumer products and also are used as residential, agricultural and industrial fuels.

NGL fractionation	For a discussion of the NGL fractionation process, please read "*The Company's Operations—NGL Pipelines & Services—NGL fractionation*" beginning on page 11 of this annual report.
NYSE	New York Stock Exchange
OPIS	Oil Price Information Service
Operating Partnership	Enterprise Products Operating L.P. and its affiliates
OTC	Olefins Terminal Corporation
Poseidon	Poseidon Oil Pipeline Company, L.L.C., an equity investment
Promix	K/D/S Promix LLC, an equity investment
Propylene fractionation	For a discussion of the propylene fractionation process, please read "*The Company's Operations—Petrochemical Services—Propylene fractionation*" beginning on page 15 of this annual report.
Resource base	The gross assemblage of various geological bodies from which oil and natural gas reserves are produced.
Rocky Mountain	Refers to the Rocky Mountain region of the United States, primarily, Wyoming, Utah, Colorado, and New Mexico
SEC	U.S. Securities and Exchange Commission
Seminole	Seminole Pipeline Company
SFAS	Statement of Financial Accounting Standards issued by the FASB
Shell	Shell Oil Company, its subsidiaries and affiliates
Spinnaker	Spinnaker Exploration Co., its subsidiaries and affiliates
Splitter III	Refers to the propylene fractionation facility we acquired from Diamond-Koch
Starfish	Starfish Pipeline Company, LLC, an equity investment
STMA	Refers to the South Texas midstream assets we purchase from El Paso in connection with Step Three of the GulfTerra Merger. Please read Note 3 of the Notes to Consolidated Financial Statements for a description of Step One, Step Two and Step Three of the GulfTerra Merger.
Sun	Sunoco Inc., its subsidiaries and affiliates
Tennessee Gas Pipeline	Refers to a major interstate natural gas pipeline, which is owned by El Paso
Tension-leg platform	A floating platform, attached to the sea floor by tensile strength steel tube tendons, used for drilling and production in deepwater.
TEPPCO	TEPPCO Partners, L.P., its subsidiaries and affiliates
Throughput	Refers to the physical movement of volumes through a pipeline
Tri-States	Tri-States NGL Pipeline LLC, an equity investment
Valero	Valero Energy Corporation, its subsidiaries and affiliates
VESCO	Venice Energy Services Company, LLC, an equity investment
Williams	The Williams Companies, Inc., its subsidiaries and affiliates
1998 Trust	Duncan Family 1998 Trust, an affiliate of EPCO
1999 Trust	EPOLP 1999 Grantor Trust, a subsidiary of EPOLP
2000 Trust	Duncan Family 2000 Trust, an affiliate of EPCO

COMPANY INFORMATION

STOCK EXCHANGE AND COMMON UNIT TRADING PRICES

Enterprise Products Partners L.P. Common Units trade on the New York Stock Exchange under the ticker symbol EPD. Enterprise had 364,297,340 Common Units outstanding at December 31, 2004. For a complete description of these units, see page 101. For a table of the high and low market prices of the Common Units by quarter, see page 109.

CASH DISTRIBUTIONS

Enterprise has paid 26 consecutive quarterly cash distributions to Unitholders since its public offering of Common Units in 1998. On January 19, 2005, the Company declared a quarterly distribution of $0.40 per unit. This distribution was made to Unitholders of record as of January 31, 2005. For a summary of the cash distributions paid, see page 134.

INDEPENDENT AUDITORS

Deloitte & Touche, LLP
Suite 2300
333 Clay Street
Houston, Texas 77002-4196

PUBLICLY TRADED PARTNERSHIP ATTRIBUTES

Enterprise Products Partners L.P. is a publicly traded master limited partnership, which operates in the following ways that are different from a publicly traded stock corporation.

Unitholders own limited partnership units instead of shares of common stock and receive cash distributions rather than dividends.

A partnership generally is not a taxable entity and does not pay federal income taxes. All of the annual income, gains, losses, deductions or credits flow through the partnership to the unitholders on a per unit basis. The unitholders are required to report their allocated share of these amounts on their income tax returns whether or not any cash distributions are made by the partnership to its unitholders.

Cash distributions paid by a partnership to a unitholder are generally not taxable, unless the amount of any cash distributed is in excess of the unitholder's adjusted basis in his partnership interest.

TRANSFER AGENT, REGISTRAR AND CASH DISTRIBUTION PAYING AGENT

Mellon Investor Services LLC

Overpeck Center
85 Challenger Road
Ridgefield Park, NJ 07660
(800) 635-9270
www.melloninvestor.com

ADDITIONAL INVESTOR INFORMATION

Additional information about Enterprise Products Partners, L.P., including our SEC annual report on Form 10-K, can be obtained by contacting Investor Relations by telephone at (713) 880-6521, writing to the Company's mailing address provided below or accessing the company's internet home page at www.epplp.com.

K-1 INFORMATION

Enterprise provides each unitholder a Schedule K-1 tax package that includes each unitholder's allocated share of reportable partnership items and other partnership information necessary to be reported on state and federal income tax returns. The K-1 provides a unitholder required tax information for their ownership interest in the partnership, just as a Form 1099-DIV does for a stockholder's ownership interest in a corporation.

Information concerning the company's K-1s can be obtained by calling toll free (800) 599-9985 or through the partnership's website at www.epplp.com.

PARTNERSHIP OFFICES

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