Enterprise Products Partners L.P.

# Investing Today for Tomorrow's Growth

Annual Report | 2005

## Company Profile

Enterprise Products Partners L.P. is one of the largest publicly traded energy partnerships with an enterprise value of approximately $15 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 32,776 miles of onshore and offshore pipelines.

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*

| | 2005 | 2004 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|
| **INCOME STATEMENT DATA:** | | | | | |
| Revenues from consolidated operations | $ 12,256,959 | $ 8,321,202 | $ 5,346,431 | $ 3,584,783 | $ 3,154,369 |
| Gross operating margin (1) | $ 1,136,347 | $ 655,191 | $ 410,415 | $ 332,349 | $ 375,944 |
| Equity in income (loss) of unconsolidated affiliates | $ 14,548 | $ 52,787 | $ (13,960) | $ 35,253 | $ 25,358 |
| Operating income | $ 663,016 | $ 422,994 | $ 248,104 | $ 194,307 | $ 286,849 |
| Net income | $ 419,508 | $ 268,261 | $ 104,546 | $ 95,500 | $ 242,178 |
| Fully diluted earnings per unit | $ 0.91 | $ 0.87 | $ 0.41 | $ 0.48 | $ 1.39 |
| Number of units for fully diluted calculation | 382,963 | 266,045 | 206,367 | 176,490 | 170,787 |
| **BALANCE SHEET DATA:** | | | | | |
| Cash and cash equivalents | $ 42,098 | $ 24,556 | $ 44,317 | $ 22,568 | $ 137,823 |
| Total assets | $ 12,591,016 | $ 11,315,461 | $ 4,802,814 | $ 4,230,272 | $ 2,424,692 |
| Total debt | $ 4,833,781 | $ 4,281,236 | $ 2,139,548 | $ 2,246,463 | $ 855,278 |
| Minority interest | $ 103,169 | $ 71,040 | $ 86,356 | $ 68,883 | $ 11,716 |
| Combined equity/partners' equity | $ 5,679,309 | $ 5,328,785 | $ 1,705,953 | $ 1,200,904 | $ 1,146,922 |
| % of net debt to total capitalization (2) | 45.3% | 44.1% | 53.9% | 63.7% | 38.2% |
| **OTHER FINANCIAL DATA:** | | | | | |
| Net capital expenditures | $ 817,449 | $ 146,928 | $ 145,913 | $ 72,135 | $ 149,896 |
| Business acquisitions, net of cash received (3) | $ 326,602 | $ 724,661 | $ 37,348 | $ 1,620,727 | $ 225,665 |
| Investments in and advances to unconsolidated affiliates | $ 88,044 | $ 64,412 | $ 471,927 | $ 13,651 | $ 116,220 |
| Total (4) | $ 1,232,095 | $ 936,001 | $ 655,188 | $ 1,706,513 | $ 491,781 |
| EBITDA (5) | $ 1,079,044 | $ 623,146 | $ 366,446 | $ 284,820 | $ 345,750 |
| Distributions from unconsolidated affiliates | $ 56,058 | $ 68,027 | $ 31,882 | $ 57,662 | $ 45,054 |
| Cash flow from operating activities | $ 631,708 | $ 391,541 | $ 424,705 | $ 326,762 | $ 277,576 |
| Distributable cash flow (5) | $ 906,079 | $ 540,493 | $ 278,766 | $ 228,194 | $ 303,904 |
| Cash distributions declared per common unit (6) | $ 1.70 | $ 1.54 | $ 1.47 | $ 1.36 | $ 1.19 |
| Annual cash distribution rate at December 31 (6) | $ 1.75 | $ 1.60 | $ 1.49 | $ 1.38 | $ 1.25 |

(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.*

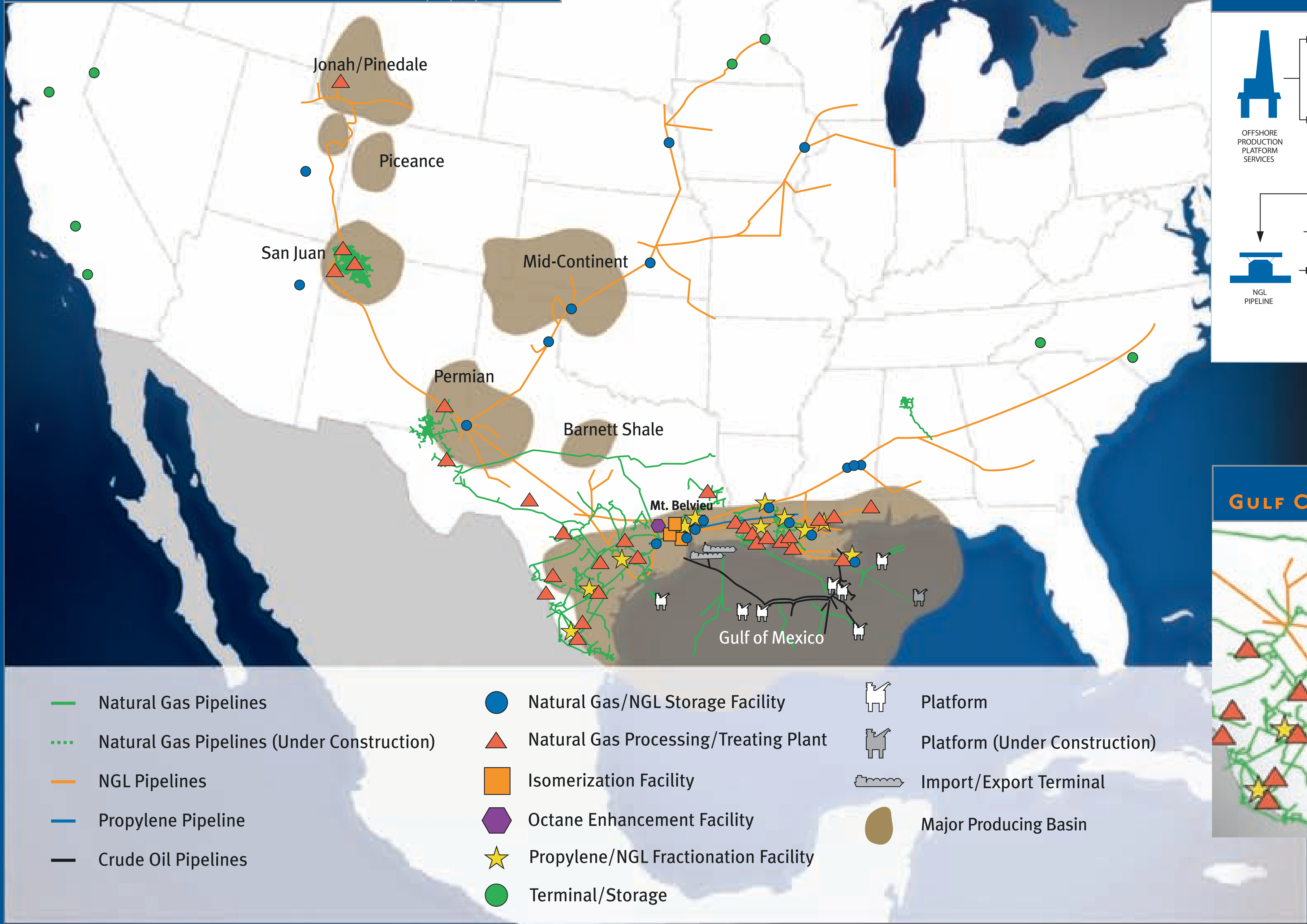
(3) *The amount for 2004 is net of $2,910,771 of non-cash consideration issued or granted relating to the GulfTerra merger.*

(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.*

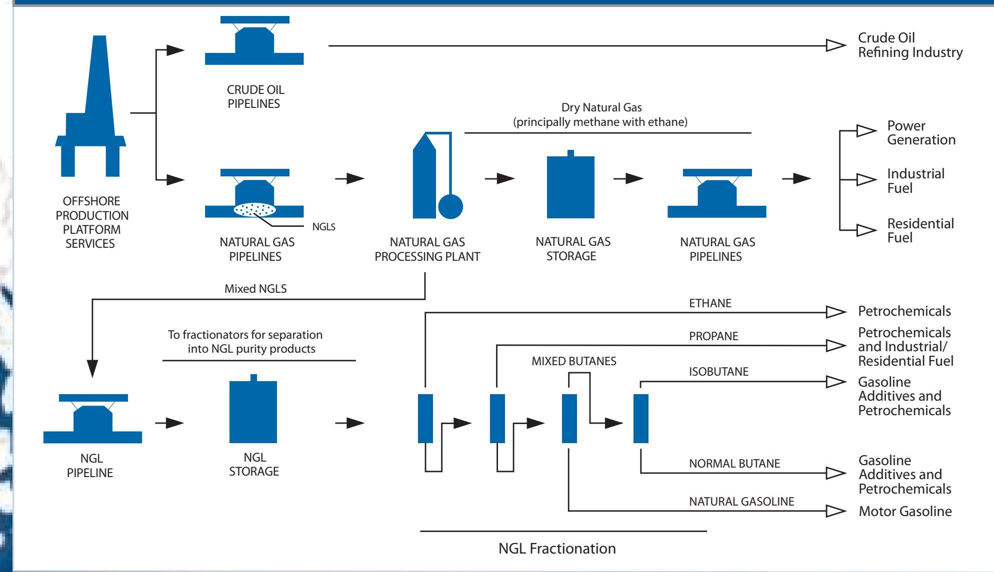
(5) *For a reconciliation of GAAP financial statements to non-GAAP financial measures, see page 127.*

(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.*

# System Map




## Enterprise Midstream Energy Value Chain




## Gulf Coast Assets

# Letter to Partners of Enterprise Products Partners L.P.

Enterprise Products Partners completed an exceptional year in 2005 as we generated record earnings and distributable cash flow and exceeded our goal for increasing cash distributions to our partners. These achievements were largely due to the successful integration of GulfTerra Energy Partners, L.P. and the vital role our fully integrated midstream value chain plays in serving the needs of our nation's growing energy markets. At the same time, we advanced Enterprise's long-term growth plans by expanding our presence into new regions, solidified our competitive position in existing markets and developed a number of new infrastructure projects to provide producers and consumers of natural gas, NGLs and crude oil with midstream energy services. These projects will extend the partnership's value chain and position Enterprise for a period of substantial growth in the years ahead.

During the year, we also faced considerable challenges. Our employees in the Gulf Coast region demonstrated remarkable dedication and determination in helping our partnership quickly recover from the effects of two major hurricanes while maintaining critical logistical services to the energy industry during and after the storms. Reflecting on 2005, it was a benchmark year in the history of the partnership as we continued to build a strong nationwide platform of assets, confirmed the value of our organic growth strategy and executed our integrated business model to deliver record financial results and create long-term value for our partners.

## 2005 – A RECORD YEAR

Enterprise reported record revenues of $12.3 billion, gross operating margin of $1.1 billion, net income of $420 million and distributable cash flow of $906 million. The benefits of business and geographic diversification from our 2004 merger with GulfTerra were evidenced by the partnership's ability to generate stable cash flows throughout 2005, despite the hurricanes and record energy price volatility. In addition, we exceeded our cost savings target for the merger which also contributed to our record earnings and cash flow.

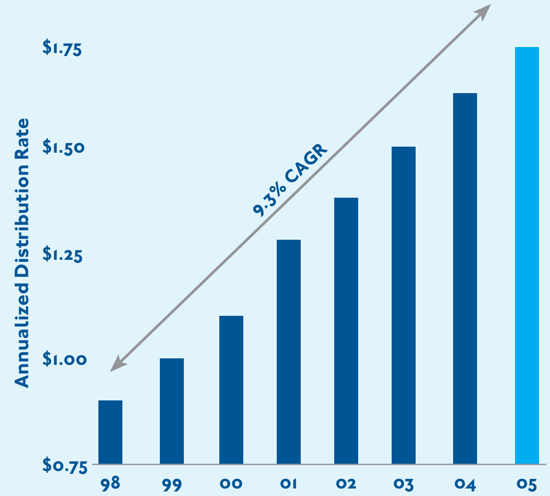
Growth in distributable cash flow supported four increases in our cash distribution rate to partners from an annualized rate of $1.60 per unit at the end of 2004 to an annualized rate of $1.75 at the end of 2005, a total increase of 9.4%. Enterprise's distributable cash flow for the year provided approximately 1.3 times coverage of the distributions declared with respect to 2005. Since completing the merger with GulfTerra, we have increased the cash distribution rate to partners in each of the five consecutive quarters by a total of 10.8% and also retained over $200 million that was reinvested to fund capital investments, retire debt and support working capital needs.

Enterprise's consistent track record of increasing cash distributions dates back to our initial public offering in July 1998. In addition to paying distributions for thirty consecutive quarters, we have increased the cash distribution rate to partners fifteen times by a total of 94%, which represents a compound annual growth rate of 9.3%.

## DESPITE HURRICANES

As you are aware, Hurricanes Katrina and Rita caused significant damage along the Gulf Coast in 2005 and resulted in lower contributions from our offshore and Louisiana onshore facilities. We are thankful that all of our employees and their families safely weathered

### GROWTH IN CASH DISTRIBUTION RATE TO PARTNERS



the storms. Our employees displayed much resolve in quickly returning our facilities to service while also dealing with their own personal situations. The partnership assisted where possible and provided temporary housing for those that were seriously affected. At the time of this writing, we are proud to say that all of Enterprise's major facilities have returned to service. We would like to recognize and thank our employees for their efforts during this challenging time.

## INVESTING TODAY FOR TOMORROW'S GROWTH

Enterprise's assets are well situated to benefit from expected growth in both the production of and demand for natural gas, NGLs and crude oil. The partnership's assets access approximately 90% of natural gas production and 85% of reserves in the lower 48 states and the Gulf of Mexico. On the demand side, we have pipeline connections to facilities that comprise more than 90% of the motor gasoline refining capacity east of the Rockies and approximately 97% of the petrochemical industry's ethylene steam cracking capacity. As strong industry fundamentals continue to create new opportunities, Enterprise will remain focused on our organic growth strategy by investing in energy infrastructure projects in developing areas such as the Jonah and Pinedale fields and Piceance basin in the Rocky Mountains, the Barnett Shale region of North Texas and the deep waters of the Gulf of Mexico. Increased production from these prolific regions will drive our expansion opportunities and ensure adequate and reliable supplies for our natural gas, refining and petrochemical customers in the future.

Through 2005, we completed construction of three of our four major offshore projects: the Marco Polo platform and associated crude oil and natural gas pipelines, the Cameron Highway Oil Pipeline System and the Constitution crude oil and natural gas pipelines. An indirect consequence of the hurricanes has been a temporary shortage of equipment available in the Gulf of Mexico to drill, complete and repair wells. This has led to delays of approximately six months in the ramp up of new production at a few developments that are served by our Marco Polo facilities and Cameron Highway Oil Pipeline. While we are disappointed in this delay, overall, we are pleased with the progression of these projects since producers have discovered additional reserves which should result in returns on investment exceeding our original forecasts.

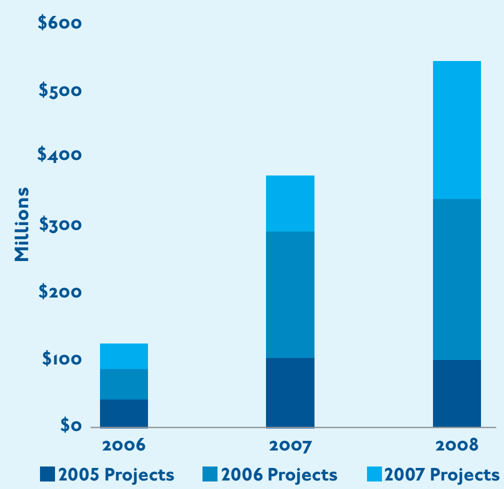
Our largest remaining offshore project, the Independence Hub and Trail, is scheduled to be completed and placed in service in early 2007. The Independence project has benefited from three additional natural gas field discoveries in the eastern Gulf of Mexico, increasing the total number of dedicated fields to ten. As a result of these additional dedications to the project, we are expanding the capacity of the platform and pipeline by 18% to one billion cubic feet per day. When operational and at full capacity, the Independence project will represent approximately 10% of total natural gas production from the Gulf of Mexico.

Once the Independence facilities are placed in service, we will have completed a major offshore construction phase resulting in the largest set of independently owned midstream assets serving the outer-continental shelf and the deepwater trend of the Gulf of Mexico. With our backbone system in place, we believe future investments will principally be smaller pipeline projects to connect new discoveries to our existing platforms and pipelines or producers building laterals to connect to our facilities.

Since we acquired the Mid-America and Seminole Pipeline Systems in 2002, one of our primary objectives has been to extend our value chain in the Rocky Mountains. We have recently executed long-term dedications with some of the largest producers in the prolific Jonah and Pinedale fields of southwest Wyoming and the Piceance basin in northwest Colorado. These dedications and expected growth support approximately $1.4 billion of investments in building natural gas pipelines and processing plants and NGL pipelines, fractionators and storage facilities.

The Jonah and Pinedale fields are among the six largest natural gas fields in the United States based on proved reserves with reserve lives of approximately forty years. During the past four years, natural gas production in the Piceance basin has increased by an average of 23% per year and is expected to be a growing source of new production to meet the country's energy needs.

### GROSS OPERATING MARGIN POTENTIAL FROM MAJOR GROWTH PROJECTS



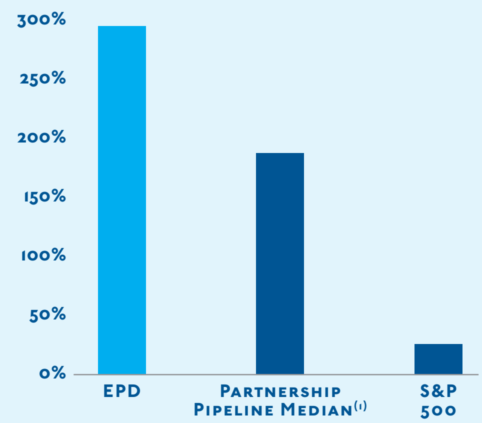
In addition to our regional strategies in the Rockies and the Gulf of Mexico, we have also identified opportunities to expand our onshore natural gas businesses in Texas and New Mexico, and our petrochemical services and industry leading NGL franchise in the Gulf Coast region. In total, we have a portfolio of approximately $3.5 billion of major growth projects that are either in service and ramping up or under development. Approximately $1.3 billion of this capital has already been invested and our capital budget for 2006 is approximately $1.7 billion.

We believe these projects will earn superior cash returns on investment as a result of the operating leverage and incremental economics from our integrated value chain where the partnership earns a fee at each processing plant, pipeline, fractionator and storage facility. We estimate that the potential gross operating margin from these investments in 2008 to be in excess of $500 million. Coupled with Enterprise's low cost of capital due to our general partner's incentive distribution rights structure, we believe these major projects will provide significant accretion and visible growth in cash flow per unit for our partners in the years ahead.

## ALIGNED INTERESTS

We continue to pursue our goal of providing our partners with an attractive total return by increasing our cash distributions and the value of Enterprise's partnership units. From our IPO in July 1998 through March 2006, we delivered a total return of approximately 298% including reinvested distributions, a compound annual growth rate of approximately 20%. We are disappointed to note that in 2005, due in part to a number of extraordinary events, the value of our partnership units did not reflect our accomplishments and the increase in the partnership's distributable cash flow per unit. We will continue to adhere to our business plan and communicate our results.

## TOTAL RETURN SINCE IPO




(1) Includes BPL, EEP, KMP, NBP, PAA and TPP. Assumes reinvested distributions/dividends.

We would like to thank our approximately 2,600 employees for their efforts and contributions to the success of Enterprise. Their commitment is evident in the recognition that our partnership receives for safety, customer service and for once again being named as one of America's most admired pipeline companies.

Approximately 25% of our employees participate in our voluntary employee unit purchase program by investing a portion of their payroll dollars in Enterprise's partnership units. Together, our senior management team and employees own approximately 36% of our outstanding partnership units. Our interests and goals continue to be closely aligned with those of our public partners.

Thank you for your support during 2005 and as we continue to build Enterprise's value in 2006.



*{pictured left to right}*

**Dr. Ralph S. Cunningham**
*Group Executive Vice President and Chief Operating Officer*

**Dan L. Duncan**
*Chairman*

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

The topsides of the Independence Hub are under construction near Corpus Christi, Texas. The Independence Hub and Trail are scheduled to be completed early in the first quarter of 2007 to coincide with first production from dedicated fields.

# Major Organic Growth Projects



Enterprise is in the second year of a major construction phase, which coincides with a period of substantial growth in U.S. natural gas production and expanding markets for energy products and services. Many of these opportunities emerged from the combination of Enterprise and GulfTerra's strategically located midstream assets, while others were developed as grassroots projects supported by new reserves and growing demand for natural gas and natural gas liquids ("NGLs"). We currently have a $3.5 billion portfolio of major growth projects and have invested $1.3 billion of this as of the end of 2005. Approximately $1.7 billion is expected to be invested during 2006 with the remainder being invested in 2007 and later. These projects are either under construction or construction has been completed and the projects are in the process of ramping up volumes as new fields commence production and connect to the pipeline or platform. We believe this portfolio of projects has the potential to generate gross operating margin in excess of $500 million in 2008.

In this section, we highlight our two largest regional growth initiatives.

## Western U.S. Growth Initiative

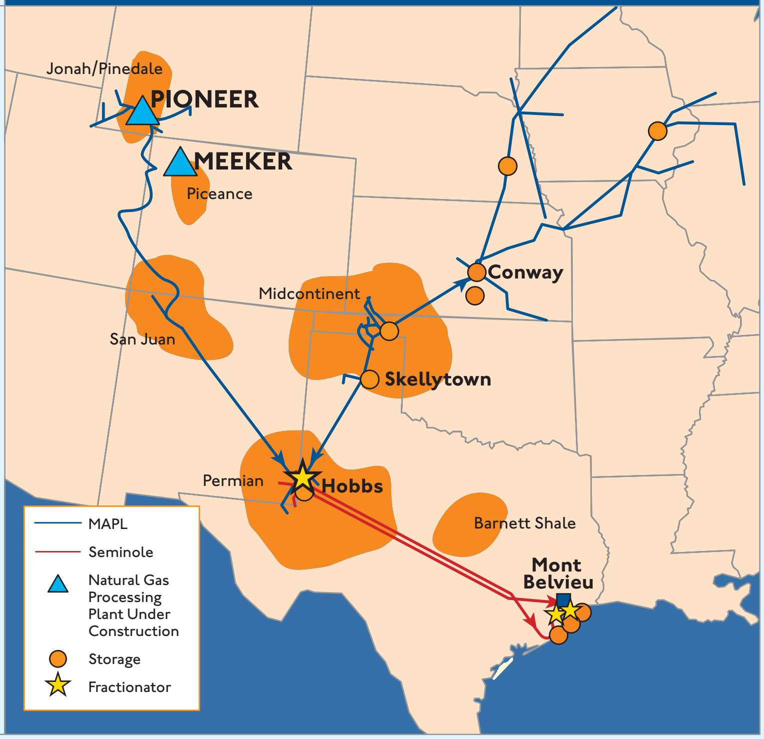
### ROCKY MOUNTAIN EXPANSION PROJECTS

The hydrocarbon-rich basins of the Rocky Mountains have become the focal point of long-term natural gas production growth in the United States. Between 2005 and 2010, industry experts expect natural gas production from the Rocky Mountains to increase by 29%, or 2.1 billion cubic feet per day ("Bcf/d"), from 7.3 Bcf/d to 9.4 Bcf/d. These basins are characterized by low producer finding and development costs, long lived reserves and limited midstream infrastructure available to gather, process and transport new production to market.

The Jonah and Pinedale fields in the Greater Green River basin of southwest Wyoming and the Piceance basin in northwest Colorado are expected to be major contributors to this growth in the Rockies. Over the last ten years the Jonah and Pinedale fields have grown from minimal production levels to approximately 1.4 Bcf/d of natural gas production largely due to enhancements in drilling and completion technology. The largest producers in the Jonah and Pinedale fields estimate that the ultimate recoverable reserves from the fields will be approximately 32 trillion cubic feet of natural gas, resulting in a reserve life approaching forty years.

While the Piceance basin is earlier in its development stage, it has experienced production increases averaging 23% per year since 2000. Current production in the Piceance basin is approximately 800 million cubic feet per day ("MMcf/d"). Natural gas production from both of these basins is rich in NGLs.

## WESTERN U.S. GROWTH INITIATIVE




## MEEKER NATURAL GAS PROCESSING PLANT

In January 2006, Enterprise entered into a life-of-lease dedication with an affiliate of EnCana Corporation for the rights to process up to 1.3 Bcf/d of EnCana's natural gas production in the Piceance basin. We have commenced construction on the Meeker cryogenic plant that will have the capacity to process up to 750 MMcf/d of natural gas and remove up to 35 MBPD of NGLs. When completed in mid-2007, the plant will be base loaded with EnCana's rich natural gas production, which is approximately 360 MMcf/d and growing. A second phase of this project would be to expand the Meeker plant to process up to 1.3 Bcf/d with the capability to extract up to 70 MBPD of NGLs. In addition, the partnership will build a 50-mile, 12-inch NGL pipeline to transport mixed NGLs extracted by the Meeker plant to the Mid-America Pipeline system ("MAPL").

## PIONEER PROCESSING PLANTS & JONAH GAS GATHERING SYSTEM

Enterprise recently purchased the Pioneer silica gel natural gas processing facility serving the Jonah and Pinedale fields from TEPPCO Partners, L.P. As part of the transaction, we also acquired the right to process natural gas production from some of the largest producers in the Jonah and Pinedale fields. In anticipation of significant future production growth, we are expanding the existing plant's conditioning capacity from 300 MMcf/d to 600 MMcf/d, and are constructing a new 650 MMcf/d cryogenic natural gas processing plant adjacent to the existing facility. When completed in the third quarter of 2007, the new cryogenic plant will have the capacity to remove up to 30 thousand barrels per day ("MBPD") of NGLs.

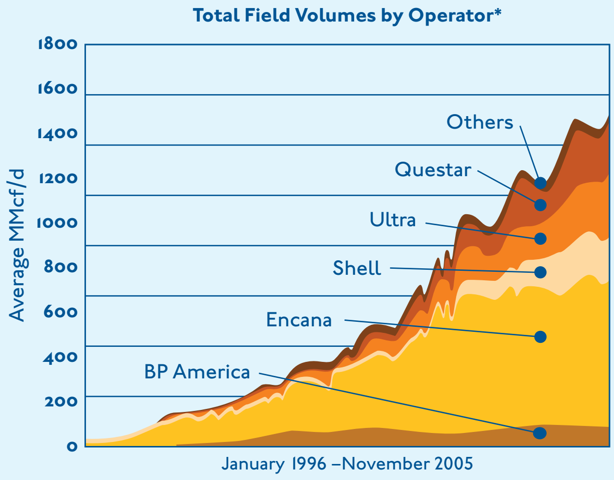
Subsequently, we executed a letter of intent with TEPPCO to provide the initial capital to fund an expansion of the Jonah Gas Gathering System and possibly acquire an interest in the pipeline system. The expansion of this system assures additional volumes for the Pioneer natural gas processing plants and NGLs for our downstream facilities.

## ROCKY MOUNTAIN EXPANSION OF MID-AMERICA PIPELINE

NGL production in the Rocky Mountain region currently averages approximately 200 MBPD and is expected to reach approximately 375 MBPD based on the projected increase in natural gas production from the Greater Green River and Piceance basins. The Rocky Mountain segment of our MAPL system, the only NGL pipeline serving the Rockies, has 225 MBPD of capacity.



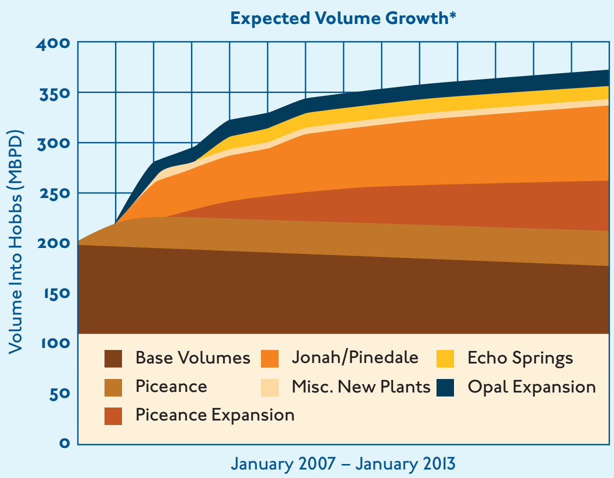
## JONAH AND PINEDALE FIELDS GROWTH




* Source IHS Energy

To accommodate this growth, we announced plans for an expansion of the Rocky Mountain segment by 50 MBPD. NGL volumes extracted by Enterprise's Pioneer and Meeker natural gas processing plants will be transported on the expanded pipeline. Construction should be completed in mid-2007.

MAPL ROCKY MOUNTAIN SYSTEM




*Source: Enterprise estimates

### NGL FRACTIONATOR IN HOBBS, NEW MEXICO AREA



The majority of the NGLs extracted in the Rocky Mountains are transported to the Texas Gulf Coast through the MAPL and Seminole pipeline systems for fractionation into NGL products, which are then distributed to the large petrochemical plants and refineries in the region. Throughout most of 2005, Enterprise's Mont Belvieu NGL fractionator was operating at full capacity and excess volumes of mixed NGLs were bypassed and fractionated at facilities owned by third parties. To capture the gross operating margin that is being foregone by our partnership due to these bypassed NGLs and to have enough capacity to absorb NGL volume growth from the Rocky Mountains, Permian basin and Mid-Continent region, we are investing in the construction of a 75 MBPD NGL fractionator and related pipeline and storage facilities at the interconnection of the MAPL and Seminole Pipelines near Hobbs, New Mexico. This project is also planned to be in service in mid-2007 in coordination with the completion of the Pioneer and Meeker natural gas processing plants and the MAPL expansion.

The Hobbs fractionator will be centrally located to provide producers of NGLs with access to Mont Belvieu, the largest NGL market in the U.S., through the Seminole Pipeline and to the second largest NGL market hub located at Conway, Kansas and to NGL consumers in the upper Midwest via the MAPL system. It will also provide NGL supplies to a growing local refinery market that consumes NGLs as a blendstock to produce motor gasoline and to northern Mexico, which has growing demand for propane. By building the fractionator at Hobbs, Enterprise will be able to maximize the use of its downstream pipeline capacity across Seminole, which has been running at or near capacity into Mont Belvieu.

### MID-CONTINENT EXPANSION OF MID-AMERICA PIPELINE & RELATED ACQUISITION

To complement the fractionator in Hobbs and the growth in the production and demand for NGLs, Enterprise also expanded its integrated network of NGL assets in the Permian basin and Mid-Continent region of the United States by purchasing three NGL underground storage facilities and four terminals during 2005 for $146 million. To complete the expansion of this integrated system, we will be increasing the capacity of the MAPL system from Conway, Kansas to the Hobbs station. We will increase the bi-directional capacity of the segment from Conway to Skellytown, Texas by approximately 67 MBPD and will increase the capacity of the segment from Skellytown to the new fractionator at Hobbs by approximately 35 MBPD. Construction will begin in mid-2006 with completion expected in early 2007.

Enterprise's western growth initiative adheres to our cornerstone principle of building integrated value chains to provide value added services to producers and consumers of hydrocarbons while enhancing our cash return on investment.

## Deepwater Gulf of Mexico Growth Initiative

The deepwater region off the Gulf of Mexico is also expected to be an important source of increasing supplies of crude oil and natural gas to help meet demand growth in the United States. The Gulf of Mexico is the largest domestic source of crude oil and condensate production, accounting for more than 25% of total production. We are in the final stages of completing the construction of our major natural gas and crude oil pipelines and production platforms which establishes our core asset position to serve producers in the Gulf of Mexico.

The Southern Green Canyon area of the deepwater Gulf of Mexico is a world class oil basin with associated natural gas that is rich in NGLs. Our access to this prolific region 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, our onshore natural gas pipelines and processing plants and NGL pipelines, fractionators and storage facilities. 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.

### CAMERON HIGHWAY OIL PIPELINE SYSTEM

Enterprise completed construction of its 500 MBPD Cameron Highway Oil Pipeline System ("CHOPS") and made first deliveries of crude oil produced from the Mad Dog and Holstein developments in the Southern Green Canyon area to major refining markets on the Texas Gulf Coast in January 2005. CHOPS, a $500 million 50/50 joint venture with an affiliate of Valero Energy Corporation, provides producers in the central and western sections of the deepwater Gulf of Mexico with a cost efficient transportation alternative to deliver crude oil to the large consuming markets in Texas. While crude oil reserves in the region served by CHOPS have significantly exceeded our original expectations due to new discoveries and extensions, the expected ramp up of transportation volumes on CHOPS has been delayed by approximately six months due to temporary shortages of equipment available to producers to bring on additional production due to the effects of Hurricanes Katrina and Rita.

CHOPS is supported by life-of-reserve dedications from BP, BHP Billiton and Unocal for their production from the Holstein, Mad Dog and Atlantis fields, and with Kerr-McGee for its production from the Constitution and Ticonderoga fields.

### CONSTITUTION OIL AND GAS PIPELINES

Enterprise recently completed the construction of its wholly-owned Constitution oil and gas pipelines. These pipelines transport crude oil and natural gas production from the Constitution and Ticonderoga fields in the Southern Green Canyon area of the Gulf of Mexico. The Constitution oil pipeline has a capacity of approximately 100 MBPD and is connected to CHOPS and the Poseidon oil pipeline at our Ship Shoal 332 junction platform. The Constitution natural gas pipeline can deliver up to 200 MMcf/d to the Anaconda Gas Gathering System. Enterprise owns 36% of the Poseidon oil pipeline and 100% of the Anaconda pipeline. First deliveries on the Constitution pipelines began in the first quarter of 2006 and are expected to ramp up over the remainder of this year.

### INDEPENDENCE HUB AND TRAIL DEVELOPMENT

In 2004, Enterprise announced the development of the Independence Hub and Trail project, consisting of a 105-foot deep-draft, semi-submersible platform and a 134-mile, 24-inch natural gas pipeline located in the eastern Gulf of Mexico. This project, in which our investment will be approximately $600 million, was designed in collaboration with a group of exploration and production companies to develop deepwater natural gas discoveries in this previously untapped region of the Gulf of Mexico.

The Independence Hub, which is 80% owned by affiliates of Enterprise, was originally designed to handle up to 850 MMcf/d of natural gas production. Due to the discovery of three additional fields in the area, the producer group executed additional fixed fee demand contracts to support a 150 MMcf/d increase in the capacity of the platform to 1 Bcf/d. The platform is designed to process production from the ten anchor fields and has excess payload capacity to tie-back up to nine additional sub sea pipelines.

The Independence Trail Natural Gas Pipeline will transport natural gas from the Independence Hub to Tennessee Gas Pipeline off the southeast coast of Louisiana. Construction of the pipeline, which is wholly-owned by an affiliate of Enterprise, and the Independence platform is scheduled to be completed in the first quarter of 2007 to coincide with the expected first production from certain of the anchor fields.



The Constitution Pipelines went into service in the first quarter of 2006. This photo shows construction activities on the pipelaying vessel, Allseas Lorelay during the second quarter of 2005.

Enterprise recently completed the expansion of an NGL fractionator at our large complex in Mont Belvieu, Texas. The expansion increased NGL fractionation capacity by 15 MBPD and improved fuel efficiency.

# 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 the most 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 also includes the partnership's natural gas processing business and its related NGL marketing activities, our NGL pipeline, storage and import/export terminaling services.

## NGL PIPELINES

| | Length In Miles | Our Ownership Interest |
|---|---|---|
| Mid-America Pipeline System | 7,226 | 100.0% |
| Dixie | 1,301 | 65.9% |
| Seminole | 1,281 | 90.0% |
| Texas NGL System | 1,039 | 100% |
| Louisiana Pipeline System | 655 | Various |
| Promix | 410 | 50% |
| Houston Ship Channel | 266 | 100% |
| Lou-Tex NGL | 204 | 100% |
| Others | 427 | Various |
| **Total** | **12,809** | |

## NATURAL GAS PROCESSING AND NGL MARKETING

The first link in our NGL value chain is natural gas processing, which includes 25 plants located in Texas, Louisiana, Mississippi, New Mexico and Wyoming. These facilities are 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 twelve 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 ten plants in Texas process natural gas produced from the South Texas, Permian and East Texas regions, the majority of which is transported through our Texas Intrastate pipeline system. Enterprise owns two gas processing plants in New Mexico including the large Chaco processing facility. The Chaco plant is integrated with our 5,400-mile San Juan gathering system that gathers approximately 1.2 Bcf of natural gas per day. We recently acquired the Pioneer silica gel plant in Wyoming, which extracts condensate and NGLs to condition natural gas produced from the Jonah and Pinedale fields.

In general, natural gas produced at the wellhead contains varying amounts of NGLs. This "rich" natural gas 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 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 thousand cubic feet ("Mcf") of natural gas 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 and the San Juan, Greater Green River and Piceance basins generally contains 2 to 3 gallons of NGLs per Mcf. Natural gas processing plants remove the NGLs from the natural gas stream. On an energy equivalent basis, NGLs usually have a greater economic value as raw materials for petrochemicals and motor gasoline than their value as components of the natural gas stream.

Enterprise restructured its natural gas processing contract portfolio in the last three years, resulting in the producer assuming all or most of the direct commodity price risk between NGLs and natural gas. At December 31, 2005, approximately 90% of the natural gas volumes were processed under contracts with a fee-based or in-kind fee component.

## NGL PIPELINES AND STORAGE

Enterprise owns interests in 12,809 miles of NGL pipelines and 148 million barrels of NGL and petrochemical storage capacity. The 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 MAPL. Enterprise's NGL pipelines connect to facilities representing approximately 97% of the ethylene steam cracking facilities, the largest single consumer of NGLs in the United States, and over 90% of the motor gasoline refineries east of the Rocky Mountains. 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.

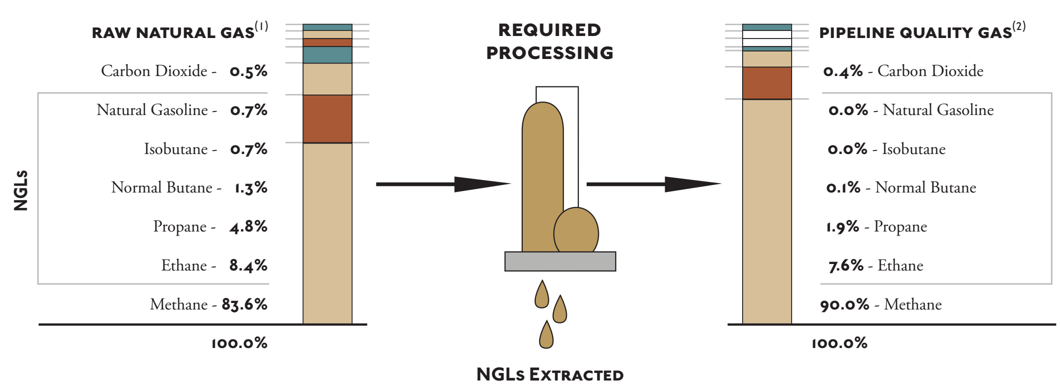
Enterprise's most significant NGL pipelines are the MAPL and Seminole pipeline systems, which total 8,507 miles. The MAPL system is a Federal Energy Regulatory Commission ("FERC") regulated NGL pipeline system consisting of three NGL pipelines: the 2,548-mile Rocky Mountain pipeline, the 2,740-mile Conway North pipeline and the 1,938-mile Conway South pipeline.

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 MAPL system interconnects with the Seminole pipeline system.

The Seminole pipeline is a FERC 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 volumes from MAPL. Mixed NGLs transported on the



## NATURAL GAS PROCESSING DIAGRAM




(1) Indicative composition of unprocessed natural gas delivered to our Neptune plant
(2) Natural gas quality required by pipelines with 1.050 MMBtu per Mcf specifications

## NGL FRACTIONATION FACILITIES

| | | Capacity MBPD | Ownership Interest | Capacity MBPD |
|---|---|---|---|---|
| Mont Belvieu | TX | 225 | 75.0% | 169 |
| South Texas | | | | |
| Shoup | TX | 69 | 100.0% | 69 |
| Armstrong | TX | 17 | 100.0% | 17 |
| Delmita | TX | 10 | 100.0% | 10 |
| Promix | LA | 145 | 50.0% | 73 |
| Norco | LA | 75 | 100.0% | 75 |
| BRF | LA | 60 | 32.2% | 19 |
| VESCO | LA | 36 | 13.1% | 5 |
| Tebone | LA | 30 | 44.3% | 13 |
| **Total Capacity** | | **667** | | **450** |

Seminole pipeline are delivered 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 Greater Green River, Piceance and San Juan basins, our MAPL 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 projects to increase our capacity. See page 4 of this annual report for a complete discussion of the Western Growth Initiative, including our NGL pipeline expansion projects, our recently announced gas processing plants in the Greater Green River Basin in southwest Wyoming and in the Piceance Basin in northwest Colorado, as well as the new fractionator to be built near the Hobbs hub located on the Texas-New Mexico border.

### 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 nine NGL fractionators with a combined net fractionation capacity of 450 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 to fractionate up to 225 MBPD of NGLs from eight supply connections. This facility, in which we own a 75% interest, fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian, San Juan, Rocky Mountains, East Texas and the U.S. Gulf Coast. Construction has been completed on a project that increased the capacity of this facility by 15 MBPD to facilitate the increased production of NGLs in the Rocky Mountain area.

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 (take-in-kind) contracts and fee-based contracts.

Enterprise and an affiliate of Dow Chemical Company each own a 50% interest in the Promix fractionator located near Napoleonville, Louisiana with the capacity to fractionate up to 145 MBPD of mixed NGLs from natural gas processing plants on the Louisiana, Mississippi and Alabama Gulf Coast. 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.

### IMPORT/EXPORT TERMINALING SERVICES

Included in NGL operations are our import and export facilities located on the Houston Ship Channel. Enterprise operates an import facility that can offload NGLs from tankers at a rate of 10,000 barrels per hour, and we also operate an export facility that can load refrigerated propane and butane on tankers at rates of up to 6,500 barrels per hour. The partnership also operates barge docks that can load or offload two barges of NGLs or refinery grade propylene simultaneously at rates of up to 5,000 barrels per hour. Our average combined import and export volumes were 119 MBPD in 2005 and 91 MBPD in 2004.

Enterprise owns the largest intrastate natural gas pipeline in Texas. We recently completed a 120 MMcf/d expansion project to facilitate increases in production from the Barnett Shale formation near Fort Worth and demand growth in the San Antonio and Austin area.

# Onshore Natural Gas Pipelines & Services



Enterprise's Onshore Natural Gas Pipelines and Services segment is comprised of the partnership's ownership interests in 17,216 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 that connect the Gulf Coast producing region to markets in the Northeast, Mid-Atlantic and Southeast. Also included in this segment are leased natural gas storage facilities 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 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. We 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. Our onshore natural gas pipelines transported 5.9 trillion British thermal units per day ("TBtus/d") in 2005, or approximately 9.5% 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 10,500 connections. This 5,406-mile system gathers natural gas from wellhead connections and delivers it to natural gas processing facilities, including our Chaco natural gas processing facility. In 2005, this system gathered approximately 1.2 TBtus/d of natural gas.

Last year, we completed a record 336 new well connections to our San Juan gathering system and are planning to connect 350 new wells in 2006. The partnership completed its system optimization project in the fourth quarter of 2005. This $43 million organic growth project will increase the capacity of our gathering system by 10%, or 130 MMcf/d, and supports additional well connects and renewed drilling in the San Juan basin by producers such as ConocoPhillips and BP.

Enterprise's largest natural gas pipeline system is the 8,222-mile Texas Intrastate System. This 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 pipeline system, the TPC Offshore natural gas gathering system and the Channel pipeline. This system transported 3.5 TBtus/d of natural gas in 2005.

On the supply side, the Texas Intrastate System benefits from increased drilling activity and production from significant new discoveries in the central Texas Gulf Coast area, increased production in the Permian Basin and the continuing development of the prolific Barnett Shale region in northeast Texas, one of the most active drilling areas in the past ten years.

On the demand side, we continue to be the primary provider of transportation and storage services to 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 completed a $27 million growth project to add 120 MMcf/d of transportation capacity to the West Texas segment of the pipeline system, bringing our total capacity on this segment to 410 MMcf/d. The additional capacity will be needed to accommodate the expected increase in deliveries of Waha and Barnett Shale natural gas supply into the San Antonio, Austin, Wharton and Agua Dulce markets in Texas.



## ONSHORE NATURAL GAS PIPELINES

| | Length In Miles | Approximate Capacity (MMcf/d, net) | Our Ownership Interest |
|---|---|---|---|
| Texas Instrastate System | 8,222 | 4,975 | 100% |
| San Juan Gathering System | 5,404 | 1,100 | 100% |
| Permian Basin System | 1,477 | 490 | 100% |
| Acadian Gas System | 1,027 | 954 | 100% |
| Alabama Intrastate System | 402 | 200 | 100% |
| Others (4 Systems)[1] | 684 | | Various |
| **Total** | **17,216** | | |

[1] Includes the Delmita, Big Thicket and Indian Springs gathering systems in Texas and the Petal Pipeline in Mississippi.

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, which are connected to interstate pipelines serving the large Northeast, Mid-Atlantic and Southeast markets. These facilities have a combined certificated working storage capacity of 15.9 Bcf and are capable of delivering in excess of 1.6 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 the Wilson salt dome 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 1.8 Bcf that serves our Acadian pipeline system.

The location of these facilities and their ability to accommodate rapid 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 supply disruptions. Our Petal facility is 93% subscribed under fixed-fee agreements, with 7 Bcf dedicated under a 20-year contract to a subsidiary of Southern Company and 3.45 Bcf subscribed to a subsidiary of BP p.l.c. The partnership's Hattiesburg facility is currently 79% subscribed and the Wilson facility in Texas is fully 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.

In 2005, we added 2.4 Bcf of working gas storage capacity at our Petal storage facility by converting an existing brine storage cavern to natural gas storage service. This $15 million expansion project was supported by a new five-year storage agreement with BP Energy Company for 1.8 Bcf of the new capacity. Additionally, due to significant customer interest received from an open season early in 2005, we started development of a new natural gas storage cavern at the Petal facility that is expected to add 5 Bcf of working gas storage capacity. Petal has received approval from the FERC to construct the cavern, which we expect to be in service the first quarter of 2008.

Enterprise's Ship Shoal 332A and B platforms form the hub for one of the largest junctions of crude oil pipelines in the Gulf of Mexico. It is the connection of 5 oil gathering pipelines that deliver oil into our Cameron Highway and Poseidon pipelines for transportation to markets in Texas and Louisiana, respectively.

# Offshore Pipelines & Services



Enterprise is a leader in the development of oil and gas pipeline and platform infrastructure serving the outer continental shelf and deepwater areas 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 incremental 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 expected to provide significant new sources of crude oil and natural gas production for the United States.

Crude oil and condensate production from the deepwater has grown from 100 MBPD in the early 1990s to approximately 1 MMBbls/d in 2005. Combined with production from shallow water, the total for Gulf of Mexico offshore is 1.5 MMBbls/d. The Minerals Mangement Service projects by 2011 that total crude oil and condensate production in the Gulf of Mexico will increase to 2.25 MMBbls/d. They also project that natural gas production from the deepwater will grow from the current rate of 4 Bcf/d to approximately 5.8 Bcf/d over this same time period. This projected growth in oil and associated natural gas production should provide our partnership with numerous opportunities to provide infrastructure services by transporting and processing additional volumes through our facilities.

During 2005, producers made significant investments in developing the deepwater Gulf of Mexico with ten new deepwater start-ups and ten new discoveries. Four of the new start-ups and four of the new discoveries are dedicated to our offshore facilities under life-of-reserve commitments. The number of producing fields utilizing our facilities increase as the hydrocarbons move downstream into our onshore infrastructure, with ten of the new start-ups and nine of the new discoveries expected to utilize some aspect of our midstream energy value chain.

## OFFSHORE NATURAL GAS PIPELINES

| | Length In Miles | Approximate Capacity (MMcf/d, net) | Our Ownership Interest |
|---|---|---|---|
| Manta Ray Offshore Gathering System | 250 | 206 | 25.7% |
| High Island Offshore System | 204 | 1,800 | 100% |
| Viosca Knoll Gathering System | 162 | 1,000 | 100% |
| Green Canyon Laterals | 136 | 649 | Various[(1)] |
| Anaconda Gathering System | 136 | 550 | 100% |
| Nautilus System | 101 | 154 | 25.7% |
| East Breaks Systems | 85 | 400 | 100% |
| Phoenix Gathering System | 78 | 450 | 100% |
| Nemo Gathering System | 24 | 102 | 33.9% |
| Falcon Gas Pipeline | 14 | 400 | 100% |
| **Total** | **1,190** | | |

(1) Our ownership interest in the Green Canyon Laterals ranges from 2.7% to 100%.

## OFFSHORE CRUDE OIL PIPELINES

| | Length In Miles | Approximate Capacity (MBPD, net) | Our Ownership Interest |
|---|---|---|---|
| Cameron Highway Oil Pipeline | 378 | 250 | 50% |
| Poseidon Oil Pipeline System | 324 | 144 | 36% |
| Constitution Oil Pipeline | 70 | 80 | 100% |
| Allegheny Oil Pipeline | 43 | 140 | 100% |
| Marco Polo Oil Pipeline | 36 | 120 | 100% |
| Typhoon Oil Pipeline | 16 | 80 | 100% |
| Tarantula Oil Pipeline | 4 | 30 | 100% |
| **Total** | **871** | | |

## OFFSHORE PLATFORMS

| | Water Depth (feet) | Approximate Capacity | | Our Ownership Interest |
|---|---|---|---|---|
| | | Natural Gas (MMcf/d, net) | Crude Oil (MBPD, net) | |
| Marco Polo, TLP | 4,300 | 150 | 60 | 50% |
| Viosca Knoll 817 | 671 | 140 | 5 | 100% |
| Garden Banks 72 | 518 | 40 | 18 | 50% |
| Ship Shoal 332 A [1] | 438 | – | – | 62% |
| Ship Shoal 332 B [1] | 438 | – | – | 50% |
| East Cameron 373 | 441 | 195 | 3 | 100% |
| Falcon Nest | 389 | 400 | 3 | 100% |

[1] The Ship Shoal 332 A and B platforms have no processing capability since they serve as junction platforms for the Manta Ray and Nemo natural gas pipelines and Poseidon, Allegheny and Cameron Highway crude oil pipelines.



## CRUDE OIL PIPELINES

The partnership owns interests in 871 miles of offshore crude oil pipelines in the Gulf of Mexico. 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.

Our oil pipelines earn revenue based on related purchase and sale agreements, which together provide an implicit fee per unit of volume 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 127 MBPD in 2005.

Our most significant investment in offshore oil pipelines has been a 50% ownership interest in the Cameron Highway Oil Pipeline System, a $500 million pipeline that we own jointly with an affiliate of Valero Energy Corporation. See page 7 for a more detailed discussion of Cameron Highway.

## NATURAL GAS PIPELINES

Enterprise owns or has an interest in 1,190 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, our pipelines generate revenue based on transportation fees charged per unit of volume transported. These agreements tend to be long-term, 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. Our offshore natural gas pipelines transported approximately 1.8 TBtus/d in 2005.

## 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
- Host pipeline compression

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 unit of volume of natural gas or crude oil multiplied by the volume delivered to the platform. Contracts for platform services often include both demand and commodity charges, with demand charges generally expiring after a fixed period of time. In 2005, our net offshore platform processing volumes were approximately 252 billion British thermal units per day of natural gas and 7 MBPD of crude oil.

Enterprise completed modifications to its octane enhancement facility to produce up to 12 MBPD of isooctane, a high octane and low vapor pressure additive for motor gasoline.

# Petrochemical Services



The Petrochemical Services segment includes the partnership's propylene fractionation and related pipeline assets, butane isomerization and octane enhancement businesses. 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 fractionation plants separate refinery grade propylene, a mixture of propane and propylene, into either polymer grade propylene, which is at least 99.5% pure propylene, or chemical grade propylene, which is approximately 92% pure propylene.

Propylene is used in the production of plastic consumer products, pharmaceuticals, fiber for carpets and upholstery, and detergents and solvents. Global demand for chemical and polymer grade propylene has grown by approximately 5.7% annually from 1999 to 2005 according to the global petrochemical consulting firm, Chemical Market Associates, Inc. ("CMAI"). CMAI estimates that the global and U.S. growth rates for 2006 through 2009 are expected to continue at the historical 5% average.

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

The partnership is in the process of expanding its integrated network of petrochemical assets in Mont Belvieu by constructing a new 15 MBPD propylene fractionator and expanding two refinery grade propylene pipelines that will add 50 MBPD of gathering capacity into Mont Belvieu. This expansion is supported by long-term contracts including a 20-year transportation agreement with Total Petrochemical U.S.A., Inc. The total investment in the new fractionator and pipeline expansions, which are expected to be operational by late 2007, is estimated to be $205 million.

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 at our large complex in Mont Belvieu and have a combined net capacity to produce 58 MBPD of polymer grade propylene.

Enterprise also owns a 30% interest in a chemical grade propylene fractionator in a joint venture with ExxonMobil Chemical near Baton Rouge, Louisiana. Enterprise designed, constructed and operates the plant while ExxonMobil supplies the feedstock to the facility and is the major customer for the end product. This facility has a gross capacity to produce 23 MBPD of chemical grade propylene.

Enterprise's petrochemical pipelines are comprised of approximately 620 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, transporting chemical grade propylene for third parties from production and storage facilities in Louisiana to Texas.

## 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 by the petrochemical industry for the production of propylene oxide, isooctane and alkylate. The annual domestic demand growth for propylene oxide during the past decade has been 1.5 times the growth rate of the U.S. gross domestic product. With the recent changes in motor gasoline specifications, we expect demand will increase for gasoline additives such as isooctane and alkylate, which are high in octane and have low vapor pressure. These octane additives use isobutane as a feedstock, which benefits our butane isomerization business.

Enterprise has been in the isomerization business since 1981 and owns three butane isomerization plants and eight 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.



Enterprise's butane isomerization facilities comprise the largest commercial isomerization complex in the world. It is expected to benefit from increased demand for isobutane as a raw material for motor gasoline additives due to recent changes in motor gasoline specifications including the use of ethanol.

Enterprise Products Partners L.P.

# Financial Section

Annual Report | 2005

**Enterprise Products Partners L.P.**
**Consolidated Financial Statements**
**For Years Ended December 31, 2005, 2004 and 2003**

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# Management's Discussion and Analysis of Financial Condition and Results of Operations

Enterprise Products Partners L.P. ("Enterprise Products Partners") is a North American midstream energy company that provides a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs") and crude oil, and is an industry leader in the development of pipeline and other midstream assets in the continental United States and Gulf of Mexico. Unless the context requires otherwise, references to "we", "us", "our", or "Enterprise Products Partners" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. and its subsidiaries.

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 Products GP"). Enterprise Products GP is owned 100% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded affiliate listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPE". The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly-owned subsidiary of EPCO. We, Enterprise Products GP, Enterprise GP Holdings and EPE Holdings are affiliates and under common control of Dan L. Duncan, the Chairman and the controlling shareholder of EPCO, Inc. ("EPCO").

This annual report contains various forward-looking statements and information based on our beliefs and those of Enterprise Products GP, as well as assumptions made by us and information currently available to us. Please read the section titled "*Cautionary Statement Regarding Forward-Looking Information*" on page 126 of this annual report.

## RECENT DEVELOPMENTS

The year 2005 was a challenging year for Enterprise Products Partners. The Gulf Coast region experienced two major hurricanes (Katrina and Rita) that affected our employees, suppliers, customers and industry. Our thoughts remain with those displaced by these storms, and we are well-positioned to assist the Gulf Coast energy industry in the rebuilding effort. Although certain of our facilities incurred structural damage as a result of the storms and other operations were interrupted, by year-end the majority of our operated facilities were at pre-hurricane production, transportation or processing levels. In particular, our Toca natural gas processing facility, which is located in coastal Louisiana and was heavily damaged in Hurricane Katrina, has recently returned to operations. For information regarding our insurance claims related to these storms, please read Note 22 of the Notes to Consolidated Financial Statements beginning on page 120.

Our growth capital spending for 2005 was a record of $743.8 million, which includes $338.6 million for our Independence Hub offshore platform and related Independence Trail Pipeline and $90.1 million for our Constitution Oil and Constitution Gas Pipelines. In addition, we recently announced two new natural gas processing projects in the Rockies. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future. In addition to our growth capital projects, we completed $326.6 million in acquisitions during 2005, the largest of which was the $145.5 million purchase of underground NGL storage facilities and propane terminals from Ferrellgas L.P. ("Ferrellgas"). For additional information regarding our growth capital spending and acquisitions, please read "*Capital Spending*" beginning on page 20.

During 2005, we completed the integration of our legacy operations with those of GulfTerra Energy Partners L.P. ("GulfTerra"). In September 2004, we completed the "GulfTerra Merger" transaction, whereby GulfTerra merged with one of our wholly owned subsidiaries. As a result of the GulfTerra Merger, GulfTerra and its subsidiaries and GulfTerra's general partner ("GulfTerra GP") became our wholly owned subsidiaries. The GulfTerra Merger greatly expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. Additionally, the GulfTerra Merger included the purchase of various midstream assets from El Paso Corporation ("El Paso") that are located in South Texas. For additional information regarding the GulfTerra Merger, please read Note 12 of the Notes to Consolidated Financial Statements beginning on page 84.

Our Cameron Highway Oil Pipeline began deliveries of Gulf of Mexico crude oil production during the first quarter of 2005 to major refining markets along the Texas Gulf Coast. The Cameron Highway Oil Pipeline can transport up to

500 MBPD of deepwater Gulf of Mexico crude oil production. We own a 50% interest in this system through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").

We completed construction of the Constitution Oil and Gas Pipelines in 2005. We own and operate these pipelines, which provide production gathering services for the Constitution and Ticonderoga fields in the Gulf of Mexico. Initial throughput is expected on the Constitution pipelines during the first quarter of 2006.

In May 2003, GulfTerra commenced a project relating to its San Juan Basin assets. The San Juan Optimization Project was substantially complete in 2005 at an approximate cost of $31 million. This project resulted in a 10% increase of capacity on our San Juan Gathering System and will increase market opportunities through a new interconnect with the Transwestern Pipeline. We connected a record 336 natural gas wells to the San Juan Gathering System during 2005.

In February 2005, we sold 17,250,000 common units (including an over-allotment amount of 2,250,000 common units which closed in March 2005), which generated net proceeds of approximately $456.7 million. In addition, our Operating Partnership sold $500 million of senior notes in February 2005. In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of up to $4 billion of additional partnership equity and/or public debt obligations. In June 2005, our Operating Partnership sold $500 million of senior notes under this registration statement. In December 2005, we sold 4,000,000 common units under this registration statement, which generated net proceeds of $98.7 million. For additional information regarding our debt obligations and capital structure, please see Notes 14 and 15 of the Notes to Consolidated Financial Statements beginning on page 92.

In October 2005, our Operating Partnership amended its revolving credit facility to increase total bank commitments from $750 million to $1.25 billion (which may be further increased to $1.4 billion upon our request, subject to certain conditions). The increase in borrowing capacity under our Multi-Year Revolving Credit Facility further enables us to meet future funding requirements of our growth capital projects. For additional information regarding our debt obligations, please see Note 14 of the Notes to Consolidated Financial Statements beginning on page 92.

The ownership of our general partner underwent a number of changes during 2005. In January 2005, affiliates of EPCO acquired a 9.9% membership interest in Enterprise Products GP and 13,454,498 of our common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and its affiliates owned 100% of the membership interests of Enterprise Products GP. In August 2005, EPCO and its affiliates contributed their membership interests in Enterprise Products GP to Enterprise GP Holdings. Affiliates of EPCO currently own 86.5% of Enterprise GP Holdings.

## CAPITAL SPENDING

We are committed to the long-term growth and viability of Enterprise Products Partners. 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 construction of new facilities and acquisitions that will expand our system of assets, and through growth capital projects. We estimate our consolidated capital spending during 2006 will approximate $1.8 billion, which includes estimated expenditures of approximately $1.7 billion for growth capital projects and acquisitions and approximately $78 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based upon our strategic operating and growth plans, which are also dependent upon our ability to generate capital from operating cash flows or otherwise obtain the capital necessary to accomplish our objectives. Our forecast may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Further, our forecast may change as a result of decisions made at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be the principal factor that determines how much we can 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 above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

The following table summarizes our capital spending by activity for the periods indicated (dollars in thousands):

| | For Year Ended December 31, | | |
|---|---|---|---|
| | **2005** | **2004** | **2003** |
| **Capital spending for business combinations and asset purchases:** | | | |
| GulfTerra Merger: | | | |
| Cash payments to El Paso, including amounts paid to acquire certain South Texas midstream assets | | $ 655,277 | |
| Transaction fees and other direct costs | | 24,032 | |
| Cash received from GulfTerra | | (40,313) | |
| Net cash payments | | 638,996 | |
| Value of non-cash consideration issued or granted | | 2,910,771 | |
| Total GulfTerra Merger consideration | | 3,549,767 | |
| Indirect interests in the Indian Springs natural gas gathering and processing assets | $ 74,854 | | |
| Additional ownership interests in Dixie Pipeline Company ("Dixie") | 68,608 | | |
| NGL underground storage and terminalling assets purchased from Ferrellgas | 145,522 | | |
| Other business combinations and asset purchases | 37,618 | 85,851 | $ 37,348 |
| Total | 326,602 | 3,635,618 | 37,348 |
| **Capital spending for property, plant and equipment:** | | | |
| Growth capital projects, net | 743,827 | 114,419 | 125,600 |
| Sustaining capital projects | 73,622 | 32,509 | 20,313 |
| Total | 817,449 | 146,928 | 145,913 |
| **Capital spending attributable to unconsolidated affiliates:** | | | |
| Purchase of 50% interest in GulfTerra GP in connection with the initial step of the GulfTerra Merger | | | 425,000 |
| Other investments in and advances to unconsolidated affiliates | 88,044 | 64,412 | 46,927 |
| Total | 88,044 | 64,412 | 471,927 |
| **Total capital spending** | $ 1,232,095 | $3,846,958 | $ 655,188 |

As shown in the preceding table, capital spending for growth capital projects is presented net of contributions in aid of construction costs of $47 million, $8.9 million and $0.9 million during 2005, 2004 and 2003, respectively. On certain of our capital projects, third parties may be obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins.

Our significant capital spending transactions during 2005 include the following:

- We paid El Paso $74.9 million for indirect majority ownership interests in the 89-mile Indian Springs Gathering System and the Indian Springs natural gas processing facility, both of which are located in East Texas.

- We paid $68.6 million for an additional 46% interest in Dixie from affiliates of ConocoPhillips and ChevronTexaco. As a result of these acquisitions, Dixie is now a majority-owned consolidated subsidiary of ours.

- We purchased three NGL underground storage facilities and four propane terminals from Ferrellgas for $145.5 million in cash. The underground storage facilities are located in Kansas, Arizona and Utah and have a combined capacity of 6.1 MMBbls. Approximately 70% of the aggregate storage capacity is leased to third party customers under fee-based contracts. The four propane terminals are located in Minnesota and North Carolina. The Minnesota facilities are connected to our Mid-America Pipeline System, and the North Carolina terminals are connected by rail to our facilities on the Gulf Coast. As part of the transaction, Ferrellgas has contracted with us to maintain a certain level of storage volume and terminal throughput for five years with the option to extend for an additional five years.

## Significant Recently Announced Growth Capital Projects

*Jonah Expansion.* In February 2006, we and TEPPCO Partners, L.P. ("TEPPCO"), an affiliate of EPCO, entered into a letter of intent related to the formation of a joint venture to expand TEPPCO's Jonah Gas Gathering System ("the Jonah system") located in the Green River Basin in southwestern Wyoming. The proposed expansion of the Jonah system would increase the natural gas gathering and transportation capacity of the Jonah system from 1.5 Bcf/d to 2.0 Bcf/d.

The letter of intent stipulates that we will be responsible for all activities related to the construction of the expansion of the Jonah system, including advancing of all expenditures necessary to plan, engineer and construct the expansion project. We estimate that total funds needed for this project will approximate $200 million and that the expansion assets will be placed in service in late 2006.

The amounts we advance to complete the expansion of the Jonah system will constitute a subscription for an equity interest in the proposed joint venture. TEPPCO has the option to return to us up to 100% of the amounts we advance (i.e., the subscription amounts). If TEPPCO returns any portion of the subscription to us, the relative interests of us and TEPPCO in the new joint venture would be adjusted accordingly. The proposed joint venture arrangement will terminate without liability to either party if TEPPCO returns 100% of the advances we make in connection with the expansion project, including carrying costs and expenses.

The general partner of TEPPCO and 2,500,000 common units of TEPPCO are owned by an affiliate of Mr. Duncan, Chairman of the board of directors of our general partner.

*Piceance Basin Gas Processing Project.* In January 2006, we announced the execution of a minimum 15-year natural gas processing agreement with an affiliate of the EnCana Corporation ("EnCana"). Under that agreement, we will have the right to process up to 1.3 Bcf/d of EnCana's natural gas production from the Piceance Basin area of western Colorado. To accommodate this production, we have begun construction of the Meeker natural gas processing facility in Rio Blanco County, Colorado. In addition, we will construct a 50-mile NGL pipeline that will connect our Meeker facility with our Mid-America Pipeline System. Phase I, which includes construction of the plant and pipeline, will provide us with 750 MMcf/d of natural gas processing capacity and the ability to recover up to 35 MBPD of NGLs. Phase II, which includes the expansion of the plant, will expand natural gas processing capacity at the facility to 1.3 Bcf/d and increase NGL extraction rates up to 70 MBPD. We expect Phase I and Phase II to be operational by mid-2007 and late-2008, respectively. Phase I is expected to cost $284 million.

*Wyoming Gas Processing Projects.* In March 2006, we purchased from TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming for $38 million in cash. In addition, we have commenced a construction project to expand the Pioneer facility from 300 MMcf/d to 600 MMcf/d at an additional cost of $21 million. We expect this expansion to be completed in mid-2006.

We have also announced our intent to build a new gas processing plant with a capacity of 650 MMcf/d adjacent to the Pioneer plant. We expect to place the new facility in service during 2007. The Pioneer expansion and the new natural gas processing plant will serve growing natural gas production in the Jonah and Pinedale fields. The cost of this new processing facility is expected to be $228 million.

*Natural Gas Storage Expansion.* In December 2005, we completed the conversion of an existing brine well located at our Petal, Mississippi storage facility to a 2.4 Bcf natural gas storage cavern at a cost of $15 million. Due to strong demand for natural gas storage, we have commenced the development of an additional storage cavern at the Petal facility that is expected to add 5 Bcf of storage capacity. This cavern is expected to cost $75 million and be placed in service during the first quarter of 2008.

*Expansion of Mont Belvieu NGL and Petrochemical Storage Services*. In November 2005, we announced an expansion of our NGL and petrochemical storage services at our complex in Mont Belvieu, Texas to improve our ability to receive and deliver NGLs and petrochemicals. The Mont Belvieu expansion projects include the drilling of two new brine production wells and the construction of two above-ground brine storage pits. The increased brine storage capability will further enable us to enhance product storage services and movement to transportation and distribution pipelines that serve the Gulf Coast region, as well as our import and export facilities on the Houston Ship Channel. As a result of these projects, we will also more than double our above-ground brine storage capabilities to 19 MMBbls and will increase our capacity to produce brine. These projects are expected to be placed in service in 2006 and 2007 and are expected to cost $77 million.

*Hobbs NGL Fractionator*. In June 2005, we announced plans to construct a new NGL fractionator, designed to handle up to 75 MBPD of mixed NGLs, located at the interconnection of our Mid-America Pipeline System and our Seminole Pipeline near Hobbs, New Mexico. Additionally, we will construct a purity ethane storage well near the new fractionator and reconfigure the interconnection between our Mid-America Pipeline System and the Seminole Pipeline. These projects are expected to cost $175 million and be placed in service by mid-2007. Our Hobbs NGL fractionator will process the increase in mixed NGLs resulting from our Phase I expansion of the Mid-America Pipeline System.

*Mid-America Pipeline System Phase I Expansion*. In January 2005, we announced an expansion of the Rocky Mountain segment of our Mid-America Pipeline System to accommodate an expected increase in mixed NGLs originating from producing basins in Wyoming, Utah, Colorado and New Mexico. The expansion project will be completed in stages and will increase throughput volumes on the segment by a total of 50 MBPD. We anticipate final completion of the Phase I expansion during the second quarter of 2007 at a cost of $187 million. We expect to receive the necessary regulatory approval and begin construction on our Phase I expansion project in the first quarter of 2006.

*Expansion of Mont Belvieu NGL Fractionator*. In January 2005, we began a project to expand the processing capacity of our Mont Belvieu NGL fractionator from 210 MBPD to 225 MBPD and to reduce energy costs. This expansion project will enable us to accommodate a portion of an expected increase in NGL production from the Rocky Mountains. The project is expected to cost approximately $41 million and be completed in mid-2006.

*Independence Hub Platform and Independence Trail Pipeline System*. In November 2004, we entered into an agreement with the Atwater Valley Producers Group for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas (collectively, the "anchor fields") of the deepwater Gulf of Mexico. First production is expected in 2007.

We are constructing and will own the Independence Hub platform, which will be located in Mississippi Canyon Block 920, at a water depth of 8,000 feet. The Independence Hub is a 105-foot deep-draft, semi-submersible platform with a two-level production deck, which will process 1 Bcf/d of natural gas. The platform, which is estimated to cost $420 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 International Inc. ("Cal Dive") to sell them a 20% indirect interest in the Independence Hub platform.

Additionally, we will construct, own and operate the 134-mile Independence Trail natural gas pipeline system, which will have a throughput capacity of 1 Bcf/d of natural gas. The pipeline system, which is estimated to cost $268 million, will transport production from the Independence Hub platform to the Tennessee Gas Pipeline.

### 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 regulations for hazardous liquid pipelines, we developed a pipeline integrity management program in 2002. In connection with the regulations for natural gas pipelines, we developed a pipeline integrity management program in 2004.

During 2005, we spent approximately $42.2 million to comply with these programs, of which $25 million was recorded as an operating expense, and the remaining $17.2 million was capitalized. We spent approximately $22.4 million to comply with these programs during 2004, of which $14.9 million was recorded as an operating expense and the remaining $7.5 million was capitalized.

We expect our net cash outlay for pipeline integrity program expenditures to approximate $63.2 million during 2006. Our forecast is net of certain costs we expect to recover from El Paso. In April 2002, GulfTerra acquired several midstream assets located in Texas and New Mexico from El Paso. These assets include the Texas Intrastate System and the Permian Basin System. El Paso agreed to indemnify GulfTerra for any pipeline integrity costs it incurred (whether paid or payable) during 2005, 2006 and 2007 with respect to such assets, to the extent that such annual costs exceed $3.3 million; however, the aggregate amount reimbursable by El Paso for these periods is capped at $50.2 million. During 2006, we expect to recover $13.8 million from El Paso related to our 2005 expenditures, which leaves a remainder of $36.4 million reimbursable by El Paso for 2006 and 2007 pipeline integrity costs.

## RESULTS OF OPERATIONS

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology employed) and products produced and/or sold.

We evaluate segment performance based on the non-generally accepted accounting principle ("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 financial measure calculated using accounting principles generally accepted in the United States of America ("GAAP") 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 (i) depreciation and amortization expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) 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 intersegment and intrasegment transactions.

For additional information regarding our business segments, please read Note 17 of the Notes to Consolidated Financial Statements beginning on page 104.

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 in 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 investments are present within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. 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 11 of the Notes to Consolidated Financial Statements beginning on page 78.

## Selected Price and Volumetric Data

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products since the beginning of 2003:

| | Natural Gas, $/MMBtu (1) | Crude Oil, $/barrel (2) | Ethane, $/gallon (1) | Propane, $/gallon (1) | Normal Butane, $/gallon (1) | Isobutane, $/gallon (1) | Natural Gasoline, $/gallon (1) | Polymer Grade Propylene, $/pound (1) | Refinery Grade Propylene, $/pound (1) |
|---|---|---|---|---|---|---|---|---|---|
| **2003** | | | | | | | | | |
| 1st Quarter | $6.58 | $34.12 | $0.43 | $0.65 | $0.76 | $0.80 | $0.85 | $0.24 | $0.21 |
| 2nd Quarter | $5.40 | $29.04 | $0.39 | $0.53 | $0.58 | $0.62 | $0.65 | $0.25 | $0.19 |
| 3rd Quarter | $4.97 | $30.21 | $0.37 | $0.56 | $0.67 | $0.68 | $0.73 | $0.21 | $0.15 |
| 4th Quarter | $4.58 | $31.18 | $0.40 | $0.58 | $0.73 | $0.71 | $0.75 | $0.22 | $0.16 |
| Average for Year | $5.38 | $31.14 | $0.40 | $0.58 | $0.68 | $0.70 | $0.74 | $0.23 | $0.18 |
| **2004** | | | | | | | | | |
| 1st Quarter | $5.69 | $35.25 | $0.43 | $0.66 | $0.76 | $0.76 | $0.87 | $0.29 | $0.26 |
| 2nd Quarter | $6.00 | $38.34 | $0.45 | $0.65 | $0.79 | $0.79 | $0.92 | $0.32 | $0.26 |
| 3rd Quarter | $5.75 | $43.90 | $0.52 | $0.79 | $0.92 | $0.92 | $1.05 | $0.32 | $0.27 |
| 4th Quarter | $7.07 | $48.31 | $0.60 | $0.85 | $1.03 | $1.04 | $1.15 | $0.40 | $0.35 |
| Average for Year | $6.13 | $41.45 | $0.50 | $0.74 | $0.88 | $0.88 | $1.00 | $0.33 | $0.29 |
| **2005** | | | | | | | | | |
| 1st Quarter | $6.27 | $49.68 | $0.52 | $0.79 | $0.98 | $1.00 | $1.14 | $0.45 | $0.39 |
| 2nd Quarter | $6.74 | $53.09 | $0.52 | $0.82 | $0.98 | $1.01 | $1.16 | $0.37 | $0.30 |
| 3rd Quarter | $8.53 | $63.08 | $0.69 | $0.97 | $1.14 | $1.26 | $1.36 | $0.37 | $0.33 |
| 4th Quarter | $13.00 | $60.03 | $0.76 | $1.06 | $1.27 | $1.34 | $1.36 | $0.50 | $0.44 |
| Average for Year | $8.64 | $56.47 | $0.62 | $0.91 | $1.09 | $1.15 | $1.26 | $0.42 | $0.37 |

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service (“OPIS”) and Chemical Market Associates, Inc. (“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.

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests, and reflect the periods in which we owned an interest in such operations. In general, the increase in volumes since 2003 is due to the assets we acquired in connection with the GulfTerra Merger, which was completed on September 30, 2004.

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| **NGL Pipelines & Services, net:** | | | |
| NGL transportation volumes (MBPD) | 1,478 | 1,411 | 1,275 |
| NGL fractionation volumes (MBPD) | 292 | 307 | 227 |
| Equity NGL production (MBPD) (1) | 68 | 76 | 43 |
| Fee-based natural gas processing (MMcf/d) | 1,767 | 1,692 | 194 |
| **Onshore Natural Gas Pipelines & Services, net:** | | | |
| Natural gas transportation volumes (BBtus/d) | 5,916 | 5,638 | 600 |
| **Offshore Pipelines & Services, net:** | | | |
| Natural gas transportation volumes (BBtus/d) | 1,780 | 2,081 | 433 |
| Crude oil transportation volumes (MBPD) | 127 | 138 | |
| Platform gas processing (BBtus/d) | 252 | 306 | |
| Platform oil processing (MBPD) | 7 | 14 | |
| **Petrochemical Services, net:** | | | |
| Butane isomerization volumes (MBPD) | 81 | 76 | 77 |
| Propylene fractionation volumes (MBPD) | 55 | 57 | 57 |
| Octane additive production volumes (MBPD) | 6 | 10 | 4 |
| Petrochemical transportation volumes (MBPD) | 64 | 71 | 68 |
| **Total, net:** | | | |
| NGL, crude oil and petrochemical transportation volumes (MBPD) | 1,669 | 1,620 | 1,343 |
| Natural gas transportation volumes (BBtus/d) | 7,696 | 7,719 | 1,033 |
| Equivalent transportation volumes (MBPD) (2) | 3,694 | 3,651 | 1,615 |

(1) Volumes have been revised to incorporate refined asset-level definitions of equity NGL production volumes.
(2) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

## Comparison of Results of Operations

The most significant recent event affecting our results of operations was the GulfTerra Merger and related transactions. Since the closing date of the GulfTerra Merger was September 30, 2004, our Statements of Consolidated Operations 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 for 2004 include four months of earnings from the South Texas midstream assets. The results of operations from our other 2005, 2004 and 2003 business combinations and asset purchases are also included in our earnings from the date of their respective acquisitions.

The following table summarizes the key components of our results of operations for the periods indicated (dollars in thousands):

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Revenues | $ 12,256,959 | $ 8,321,202 | $ 5,346,431 |
| Operating costs and expenses | 11,546,225 | 7,904,336 | 5,046,777 |
| General and administrative costs | 62,266 | 46,659 | 37,590 |
| Equity in income (loss) of unconsolidated affiliates | 14,548 | 52,787 | (13,960) |
| Operating income | 663,016 | 422,994 | 248,104 |
| Interest expense | 230,549 | 155,740 | 140,806 |
| Net income | 419,508 | 268,261 | 104,546 |

Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 67% of total consolidated revenues for each of 2005 and 2004, and 68% of total consolidated revenues for 2003. Revenues from the sale of petrochemical products within the Petrochemical Services segment accounted for 11%, 13% and 12% of total consolidated revenues for 2005, 2004 and 2003, respectively. Revenues from the transportation, sale and storage of natural gas using onshore assets accounted for 13%, 10% and 11% of total consolidated revenues for 2005, 2004 and 2003, respectively.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2005** | **2004** | **2003** |
| Gross operating margin by segment: | | | |
| NGL Pipelines & Services | $ 579,706 | $ 374,196 | $ 310,677 |
| Onshore Natural Gas Pipelines & Services | 353,076 | 90,977 | 18,345 |
| Offshore Pipeline & Services | 77,505 | 36,478 | 5,561 |
| Petrochemical Services | 126,060 | 121,515 | 75,885 |
| Other, non-segment | | 32,025 | (53) |
| Total segment gross operating margin | $ 1,136,347 | $ 655,191 | $ 410,415 |

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 cumulative effect of changes in accounting principles, please read "*Other Items*" on page 46.

***Comparison of Year Ended December 31, 2005 with Year Ended December 31, 2004***

Revenues for 2005 increased $3.9 billion over those recorded during 2004. The trend in consolidated revenues can be attributed to (i) a $2.2 billion increase in revenues from our NGL and petrochemical marketing activities resulting from an increase in sales volumes and energy commodity prices in 2005 relative to 2004; (ii) the addition of $1.5 billion in revenues from acquired or consolidated businesses, particularly those generated by the GulfTerra and South Texas midstream assets; and (iii) a $0.2 billion increase in revenues from the sale of natural gas attributable to higher natural gas prices year-to-year.

Consolidated costs and expenses increased $3.7 billion year-to-year primarily due to (i) higher energy commodity prices, which resulted in a $2.2 billion increase in the cost of sales of natural gas, NGLs and petrochemical products; and (ii) the addition of $1.4 billion in costs and expenses attributable to acquired or consolidated businesses. General and administrative costs increased $15.6 million period-to-period as a result of our expanded business activities.

Changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was 91 cents per gallon ("CPG") during 2005 versus 73 CPG during 2004 – a year-to-year increase of 25%. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $8.64 per MMBtu during 2005 versus $6.13 per MMBtu during 2004. Polymer grade propylene index prices increased 27% year-to-year and refinery grade propylene index prices increased 28% year-to-year. For historical pricing information of natural gas, crude oil and NGLs, please see the table on page 26.

Equity earnings from unconsolidated affiliates decreased $38.2 million year-to-year. Equity earnings for 2005 include a full year of our share of earnings from investments we acquired in connection with the GulfTerra Merger, including an $11.5 million charge associated with the refinancing of Cameron Highway's project debt. Fiscal 2004 includes $32 million of equity earnings from GulfTerra GP, which we consolidated in September 2004 as a result of completing the GulfTerra Merger. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to a $240 million increase in operating income year-to-year.

Interest expense increased $74.8 million year-to-year primarily due to debt we incurred in 2004 as a result of the GulfTerra Merger and the issuance of additional senior notes in 2005. Our average debt principal outstanding was $4.6 billion in 2005 compared to $2.8 billion in 2004.

As a result of items noted in the previous paragraphs, net income increased $151.2 million year-to-year to $419.5 million in 2005 compared to $268.3 million in 2004. Net income for both years includes the recognition of non-cash amounts related to the cumulative effects of changes in accounting principles. We recorded a $4.2 million charge in 2005 and a $10.8 million benefit in 2004 related to such changes. For additional information regarding the cumulative effect of changes in accounting principles we recorded in 2005 and 2004, please read Note 8 of the Notes to Consolidated Financial Statements beginning on page 74.

Due to our geographic and business diversification, Hurricanes Katrina (August 2005) and Rita (September 2005) had varying effects across our business segments. The hurricanes impacted supply and demand for natural gas, NGLs, crude oil and motor gasoline. In general, this resulted in an increase in energy commodity prices, which was exacerbated in certain regions due to local supply and demand imbalances. The disruptions in natural gas, NGL and crude oil production along the U.S. Gulf Coast resulted in decreased volumes for some of our pipeline systems, natural gas processing plants and NGL fractionators, which in turn caused a decrease in our gross operating margin from certain operations. In addition, operating costs at certain of our plants and pipelines were negatively impacted due to the higher fuel costs. These adverse effects were mitigated by increases in gross operating margin from certain of other operations, which benefited from increased demand for NGLs and octane additives, regional demand for natural gas and the general increase in commodity prices.

We estimate that Hurricanes Katrina and Rita reduced our gross operating margin in 2005 by approximately $48 million as a result of decreased transportation and processing volumes and higher hurricane-related expenses and insurance premium costs. Our 2005 results of operations reflect a $4.8 million cash receipt related to the settlement of certain business interruption insurance claims from Hurricane Ivan in September 2004.

We are at varying stages of the insurance claims process with respect to these hurricanes and expect to receive additional insurance recoveries in 2006 and 2007. For additional information regarding our insurance claims related to these storm events, please read "*Results of Operations – Significant Risks and Uncertainties – Hurricanes*" beginning on page 31.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

*NGL Pipelines & Services*. Gross operating margin from this business segment was $579.7 million for 2005 versus $374.2 million for 2004. The $205.5 million increase in gross operating margin consists of the following: (i) a $186.9 million increase from natural gas processing and related NGL marketing activities; (ii) a $21.3 million increase from NGL fractionation; and (iii) a $2.7 million decrease from NGL pipelines and related storage services.

The $186.9 million year-to-year increase in gross operating margin from natural gas processing and related NGL marketing activities includes $122.3 million from natural gas plants acquired in connection with the GulfTerra Merger and $66.9 million from NGL marketing activities. Our marketing activities benefited from higher sales volumes and commodity prices during 2005 compared to 2004.

The $21.3 million year-to-year increase in gross operating margin from NGL fractionation includes (i) $14.9 million of improved results from our Mont Belvieu facility; (ii) $14 million from assets acquired in connection with the GulfTerra Merger; and (iii) a $9 million decrease from our Louisiana NGL fractionators, particularly Norco, which suffered a loss of processing volumes due to Hurricane Katrina. Our Norco NGL fractionator is expected to return to normal operating rates during 2006.

The $2.7 million year-to-year decrease in gross operating margin from NGL pipelines and related storage services was due to a variety of reasons, including (i) a net $11.2 million decrease from our Mid-America Pipeline System and Seminole Pipeline primarily due to higher fuel costs and pipeline integrity expenses; (ii) a $4.9 million decrease from our Louisiana Pipeline System primarily due to hurricane effects; (iii) a net $6.9 million increase from our import and export facilities and related Houston Ship Channel pipeline attributable to increased volumes; and (iv) a net $8.9 million increase due to acquired assets and consolidation of former equity method investees.

*Onshore Natural Gas Pipelines & Services*. Gross operating margin from this business segment was $353.1 million for 2005 compared to $91 million for 2004. The $262.1 million increase in gross operating margin is primarily due to onshore natural gas pipelines and storage assets acquired in connection with the GulfTerra Merger. Gross operating margin from this segment is largely attributable to contributions from our San Juan Gathering System, Texas Intrastate System and Permian Basin System, which together generated gross operating margins in 2005 of $290.4 million. Our Petal and Hattiesburg natural gas storage facilities generated $38.7 million of gross operating margin in 2005. The San Juan Gathering System, Texas Intrastate System, Permian Basin System and Petal and Hattiesburg natural gas storage facilities were acquired in connection with the GulfTerra Merger.

*Offshore Pipelines & Services*. Gross operating margin from this business segment was $77.5 million for 2005 compared to $36.5 million for 2004. The $41 million increase in gross operating margin is primarily due to offshore Gulf of Mexico assets acquired in connection with the GulfTerra Merger. The year-to-year change in gross operating margin consists of the following: (i) a $20.1 million increase from offshore natural gas pipelines; (ii) a $26.4 million increase from offshore platforms; and (iii) a $5.5 million decrease from offshore crude oil pipelines, which includes an $11.5 million charge related to the refinancing of Cameron Highway's project debt in 2005.

*Petrochemical Services.* Gross operating margin from this business segment was $126.1 million for 2005 compared to $121.5 million during 2004. The $4.6 million increase in gross operating margin is primarily due to improved results from isomerization services and octane additive production activities, both of which benefited from increased demand for motor gasoline in 2005.

*Other*. Gross operating margin from this segment pertains to equity earnings we recorded from GulfTerra GP prior to its consolidation with our financial results in September 2004.

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

Revenues for 2004 increased $3 billion over those recorded during 2003. The increase in consolidated revenues can be attributed to (i) a $2.1 billion increase in revenues from our NGL and petrochemical marketing activities primarily resulting from an increase in sales volumes and energy commodity prices in 2004 relative to 2003; and (ii) the addition of $0.8 billion in revenues from acquired assets and business combinations, particularly those resulting from the GulfTerra Merger in September 2004.

Consolidated costs and expenses increased $2.9 billion year-to-year primarily due to (i) higher energy commodity prices, which resulted in a $2 billion increase in the cost of sales of our NGL and petrochemical marketing activities; (ii) the addition of $0.6 billion in costs and expenses attributable to acquired or consolidated businesses during 2004; and (iii) a $0.2 billion increase in the costs of our natural gas processing business primarily due to an increase in volumes. General and administrative costs increased $9.1 million year-to-year as a result of expanded business activities.

As noted previously, changes in our revenues and costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was 73 CPG during 2004 versus 57 CPG during 2003 – a year-to-year increase of 28%. The market price of natural gas averaged $6.13 per MMBtu during 2004 versus $5.38 per MMBtu during 2003. Polymer grade propylene index prices increased 44% year-to-year and refinery grade propylene index prices increased 61% year-to-year.

Equity earnings from unconsolidated affiliates increased $66.7 million year-to-year. Fiscal 2004 includes $32 million of equity earnings from GulfTerra GP, which we acquired in December 2003. Fiscal 2003 includes a $22.5 million non-cash asset impairment charge related to our octane additive production facility. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to a $174.9 million increase in operating income year-to-year.

Interest expense increased $14.9 million year-to-year primarily due to debt we incurred in 2004 as a result of the GulfTerra Merger. Our average debt principal outstanding was $2.8 billion during 2004 compared to $2 billion during 2003.

As a result of the items noted in previous paragraphs, net income increased $163.8 million to $268.3 million for 2004 compared to $104.5 million for 2003. Net income for 2004 includes a $10.8 million benefit associated with the cumulative effect of changes in accounting principles.

The following information highlights the significant year-to-year variances in gross operating margin by business segment:

*NGL Pipelines & Services*. Gross operating margin from this business segment was $374.2 million for 2004 versus $310.7 million for 2003. The $63.5 million increase in gross operating margin includes (i) a $82 million increase from our natural gas processing business, which includes $61.2 million from assets acquired in connection with the GulfTerra Merger; (ii) a $20.9 million decrease from our NGL pipelines and related storage services resulting from an increase in pipeline integrity expenses and a decrease in transportation volumes on certain of our pipelines; and (iii) a $6.8 million increase from our NGL fractionation business, which includes $5.8 million associated with the South Texas NGL fractionators we acquired in connection with the GulfTerra Merger.

*Onshore Natural Gas Pipelines & Services*. Gross operating margin from this business segment was $91 million for 2004 compared to $18.3 million for 2003. The $72.7 million increase in gross operating margin for this segment is also attributable to assets acquired in connection with the GulfTerra Merger.

*Offshore Pipelines & Services*. Gross operating margin from this business segment was $36.5 million for 2004 compared to $5.6 million for 2003. The $30.9 million increase from this segment is primarily due to offshore Gulf of Mexico assets acquired in connection with the GulfTerra Merger.

*Petrochemical Services*. Gross operating margin from this business segment was $121.5 million in 2004 compared to $75.9 million in 2003. Gross operating margin from our octane additive production business increased $34.4 million year-to-year primarily due to our consolidation of the results of operations of Belvieu Environmental Fuels ("BEF"). We acquired a controlling ownership interest in BEF, which owns our octane additive production facility, in September 2003. In addition, the results of operations for 2003 include the recognition by us of our share (or $22.5 million) of a $67.5 million non-cash asset impairment charge recorded by BEF prior to its consolidation. Gross operating margin from propylene fractionation increased $10.1 million year-to-year primarily due to higher petrochemical marketing sales volumes, which benefited from the effects of higher polymer grade propylene prices in 2004 relative to 2003.

## Significant Risks and Uncertainties – Hurricanes

The following is a discussion of the general status of insurance claims related to recent hurricanes that affected our assets. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available to us.

*Hurricane Ivan insurance claims*. Our final purchase price allocation for the GulfTerra Merger includes a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain GulfTerra assets caused by Hurricane Ivan which struck the eastern U.S. Gulf Coast region in September 2004 prior to the GulfTerra Merger. These expenditures represent our costs to restore the damaged facilities to operation. Since this loss event occurred prior to completion of the GulfTerra Merger, the claim was filed under the insurance program of GulfTerra and El Paso. Since year-end 2005, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million by mid-2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the fourth quarter of 2005, we received $4.8 million from such claims. In addition, we estimate an additional $15 million to $16 million will be received during the first quarter of 2006. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period in which funds are received.

*Hurricanes Katrina and Rita insurance claims*. Hurricanes Katrina and Rita affected certain of our Gulf Coast assets in August and September of 2005, respectively. Inspection, evaluation of property damage to our facilities and repairs are a continuing effort. We expensed $5 million during the third quarter of 2005 related to property damage insurance deductibles for these storms. To the extent that insurance proceeds from property damage claims do not cover our actual cash expenditures (in excess of the insurance deductibles we have expensed), such shortfall will be expensed when realized. We recorded $15.5 million of estimated recoveries from property damage claims based on amounts expended through December 31, 2005. In addition, we expect to file business interruption claims for losses related to these hurricanes. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

### General Outlook for 2006

We expect our results of operations to be affected by the following key trends and events during 2006.

- We believe that drilling activity in the major producing areas where we operate, including the Rocky Mountains, San Juan Basin and deepwater Gulf of Mexico, will result in increased demand for our midstream energy services. As a result, we expect higher transportation and processing volumes for our assets due to increased natural gas and crude oil production from both the Rocky Mountains and deepwater Gulf of Mexico. Hurricanes Katrina and Rita reduced natural gas and crude oil production in the Gulf of Mexico during the latter half of 2005. Barring any other major storms or similar disruptions, we believe that Gulf of Mexico production will return to pre-hurricane levels by mid-2006.

- We are currently in a major asset construction phase that began in 2005. With several major projects underway and announced to begin this year, fiscal 2006 will be a transition year as we continue to invest in multiple projects that will further diversify our portfolio of midstream assets. We believe that completion of these projects will generate additional cash flows beginning in 2006. Our significant growth capital projects are supported by long-term agreements with producers in significant supply basins, which include the Piceance Basin in Colorado, the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming and the deepwater Gulf of Mexico.

- We believe that our natural gas and NGL facilities located in central Louisiana and our Marco Polo Oil Pipeline, Marco Polo platform and Cameron Highway Oil Pipeline located in the Gulf of Mexico are poised to benefit as production volumes increase from developments in the Southern Green Canyon area of the deepwater Gulf of Mexico. Volumes on our Cameron Highway Oil Pipeline were adversely affected during the fourth quarter of 2005 due to disruption of production caused by Hurricanes Katrina and Rita, and these volumes are expected to continue to be adversely affected during the first quarter of 2006. However, we currently expect significant increases in Cameron Highway Oil Pipeline volumes during the remainder of 2006 as production increases, including production at the Mad Dog field and initial production from the Ticonderoga, K2 North and Timon fields.

- We believe that the strength of the domestic and global economy will continue to drive increased demand for all forms of energy despite higher commodity prices. Our largest NGL consuming customers in the ethylene industry continue to see strong demand for their products, which enables 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 for the ethylene industry.

## 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 and short-term revolving credit arrangements. 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 equity and debt securities. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At December 31, 2005, we had $42.1 million of unrestricted cash on hand and approximately $727 million of available credit under our Operating Partnership's Multi-Year Revolving Credit Facility. In total, we had approximately $4.8 billion in principal outstanding under various debt agreements at December 31, 2005.

As a result of our growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that financing arrangements to support our growth activities 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.

For additional information regarding our growth strategy, please read "*Capital Spending*" beginning on page 20.

### Credit Ratings

At February 15, 2006, the credit ratings of our Operating Partnership's debt securities were Baa3 with a stable outlook as rated by Moody's Investor Services; BBB- with a stable outlook as rated by Fitch Ratings; and BB+ with a stable outlook as rated by Standard and Poor's.

In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, the Operating Partnership entered into a $54 million, ten-year, fixed rate loan with the Mississippi Business Finance Corporation ("MBFC"). The indenture agreement for this loan contains an acceleration clause whereby if the Operating Partnership's credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or lower, 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.

### Registration Statements

From time-to-time, we issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of equity and debt securities. After taking into account our issuance of securities under this universal registration statement during 2005, we can issue an additional $3.4 billion of securities under this registration statement as of February 15, 2006.

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 into the purchase of additional common units. We have a registration statement on file with the SEC covering the issuance of up to 15,000,000 common units in connection with the DRIP. A total of 10,925,102 common units have been issued under this registration statement through February 15, 2006.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. A total of 260,222 common units have been issued to employees under this plan through February 15, 2006.

For information regarding our public debt obligations or partnership equity, please read Notes 14 and 15, respectively, of the Notes to Consolidated Financial Statements beginning on page 92.

## Debt Obligations

For detailed information regarding our consolidated debt obligations and those of our unconsolidated affiliates, please read Note 14 of the Notes to Consolidated Financial Statements beginning on page 92. The following table summarizes our consolidated debt obligations at the dates indicated (dollars in thousands):

| | At Year Ended December 31, 2005 | 2004 |
|---|---|---|
| Operating Partnership debt obligations: | | |
| 364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (1) | | $ 242,229 |
| Multi-Year Revolving Credit Facility, variable rate, due October 2010 | $ 490,000 | 321,000 |
| Seminole Notes, 6.67% fixed rate, repaid December 2005 | | 15,000 |
| 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 |
| 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 | 500,000 |
| Senior Notes F, 4.625% fixed rate, due October 2009 | 500,000 | 500,000 |
| Senior Notes G, 5.60% fixed rate, due October 2014 | 650,000 | 650,000 |
| Senior Notes H, 6.65% fixed rate, due October 2034 | 350,000 | 350,000 |
| Senior Notes I, 5.00% fixed rate, due March 2015 (2) | 250,000 | |
| Senior Notes J, 5.75% fixed rate, due March 2035 (3) | 250,000 | |
| Senior Notes K, 4.950% fixed rate, due June 2010 (4) | 500,000 | |
| Dixie Revolving Credit Facility, variable rate, due June 2007 | 17,000 | |
| Debt obligations assumed from GulfTerra | 5,068 | 6,469 |
| Total principal amount | 4,866,068 | 4,288,698 |
| Other, including unamortized discounts and premiums and changes in fair value (5) | (32,287) | (7,462) |
| Subtotal long-term debt | 4,833,781 | 4,281,236 |
| Less current maturities of debt (6) | | (15,000) |
| Long-term debt | $ 4,833,781 | $ 4,266,236 |
| | | |
| Standby letters of credit outstanding | $ 33,129 | $ 139,052 |

(1) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility. For additional information regarding this equity offering, see Note 15 of the Notes to Consolidated Financial Statements on page 97.
(2) Senior Notes I were issued at 99.379% of their face amount in February 2005.
(3) Senior Notes J were issued at 98.691% of their face amount in February 2005.
(4) Senior Notes K were issued at 99.834% of their face amount in June 2005.
(5) The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts. The December 31, 2004 amount includes $1.8 million related to fair value hedges and $9.2 million in net unamortized discounts.
(6) In accordance with Statement of Financial Accounting Standards ("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 Facility using proceeds from an equity offering completed in February 2005.

Our significant debt-related transactions during 2005 were as follows:

- In February 2005, we completed repayment of the 364-Day Acquisition Credit Facility using proceeds from our February 2005 equity offering.

- Also in February 2005, we issued $500 million in aggregate principal amount of Senior Notes I and J. A portion of the proceeds from these Senior Notes were used to repay Senior Notes A, which matured in March 2005.

- In June 2005, we issued $500 million in aggregate principal amount of Senior Notes K.

- In October 2005, the borrowing capacity under the Operating Partnership's Multi-Year Revolving Credit Facility was increased from $750 million to $1.25 billion, with the possibility that the borrowing capacity could be increased further to $1.4 billion (subject to certain conditions). In addition, the maturity date for debt outstanding under this facility was extended from September 2009 to October 2010.

- In December 2005, Seminole Pipeline Company, a majority-owned subsidiary, made the final payment on its indebtedness.

We have three unconsolidated affiliates with long-term debt obligations. The following table summarizes the debt obligations of these unconsolidated affiliates (on a 100% basis to the joint venture) at December 31, 2005 and our ownership interest in each entity on that date (dollars in thousands):

| | Our Ownership Interest | Total |
|---|---|---|
| Cameron Highway | **50.0%** | $ 415,000 |
| Poseidon | **36.0%** | 95,000 |
| Evangeline | **49.5%** | 30,650 |
| Total | | $ 540,650 |

For information regarding the scheduled maturities of our consolidated debt obligations and estimated cash payments for interest, please read "*Contractual Obligations*" beginning on page 39.

### Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in thousands). For information regarding the individual components of our cash flow amounts, please see the Statements of Consolidated Cash Flows on page 57.

| | For Year Ended December 31, | | |
|---|---|---|---|
| | **2005** | **2004** | **2003** |
| Net cash provided from operating activities | $ 631,708 | $ 391,541 | $ 424,705 |
| Net cash used in investing activities | 1,130,395 | 941,424 | 662,076 |
| Net cash provided by financing activities | 516,229 | 543,973 | 254,020 |

We prepare our Statements of Consolidated Cash Flows using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and the like; (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables; and (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of assets or gains or losses from the extinguishment of debt. In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory balances are influenced by changes in commodity prices and the quantity of products held in connection with our marketing activities.

In addition, non-cash items that were subtracted in determining income must be added back in determining net cash flows from operating activities. Each of these non-cash items is a charge against income but does not decrease cash. Items to be added back include depreciation, amortization of intangibles, amortization in interest expense, operating lease expense paid by EPCO, provisions for impairments of long-lived assets and increases in deferred tax liabilities. Conversely, non-cash items that were added in determining income (such as amortization of bond premiums or decreases in deferred tax liabilities) must be subtracted in determining net cash flows from operating activities.

Equity in income or loss from unconsolidated affiliates is also a non-cash item that must be removed in determining net cash flows from operating activities. Our cash flows from operating activities reflect the actual cash distributions we receive from such investees.

Net cash provided from operating activities is largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs and crude oil. 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.

Cash used in investing activities primarily represents expenditures for capital projects, business combinations, asset purchases and investments in unconsolidated affiliates. Cash provided by (or used in) financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant year-to-year variances in our cash flow amounts:

***Comparison of Year Ended December 31, 2005 with Year Ended December 31, 2004***

*Operating activities*. Net cash provided from operating activities was $631.7 million in 2005 compared to $391.5 million in 2004. The $240.2 million, or 61%, year-to-year increase in net cash provided from operating activities is primarily due to:

- Net income adjusted for all non-cash items and the net effects of changes in operating accounts increased $252.1 million year-to-year primarily due to the addition of earnings from assets acquired in connection with the GulfTerra Merger in September 2004.

- Distributions received from unconsolidated affiliates decreased by $12 million year-to-year primarily due to the consolidation of GulfTerra GP in September 2004 partially offset by increased cash distributions from offshore Gulf of Mexico investments. GulfTerra GP accounted for $32.3 million in cash distributions from unconsolidated affiliates during 2004.

The carrying value of our inventories increased from $189 million at December 31, 2004 to $339.6 million at December 31, 2005. The $150.6 million increase is primarily due to higher commodity prices during 2005 when compared to 2004, and an increase in volumes purchased and held in inventory in connection with our marketing activities at December 31, 2005 versus December 31, 2004.

*Investing activities*. Cash used in investing activities was $1.1 billion in 2005 compared to $941.4 million in 2004. Expenditures for growth and sustaining capital projects (net of contributions in aid of construction costs) increased $670.5 million year-to-year primarily due to cash payments associated with our offshore Gulf of Mexico projects. Our cash outlays for asset purchases and business combinations were $326.6 million in 2005 versus $724.7 million in 2004. The 2004 period includes $638.8 million paid to El Paso in connection with the GulfTerra Merger.

Our investments in unconsolidated affiliates increased to $87.3 million in 2005 from $57.9 million in 2004. In 2005, we contributed $72 million to Deepwater Gateway, L.L.C. to fund our share of the repayment of its term loan. During 2004, we used $27.5 million to acquire additional ownership interests in Promix, which owns the Promix NGL fractionator, and contributed $24 million to Cameron Highway for the construction of its crude oil pipeline.

Cash flows related to investing activities for 2005 also include (i) a $47.5 million cash receipt related to the partial return of our investment in Cameron Highway; and (ii) a $42.1 million cash receipt from the sale of our investment in Starfish Pipeline Company, LLC ("Starfish"). The sale of our Starfish investment was required by the FTC in order to gain its approval for the GulfTerra Merger.

For additional information related to our capital spending program, please read "*Capital Spending*" beginning on page 20.

*Financing activities*. Cash provided by financing activities was $516.2 million in 2005 compared to $544 million in 2004. We had net borrowings under our debt agreements of $561.7 million during 2005 versus $125.6 million during 2004. During 2005, we issued an aggregate $1 billion in senior notes, the proceeds of which were used to temporarily reduce debt outstanding under our bank credit facilities, repay Senior Notes A and for general partnership purposes, including capital expenditures, asset purchases and business combinations. In addition, we repaid the remaining $242.2 million that was outstanding at the end of 2004 under our 364-Day Acquisition Credit Facility using proceeds from our February 2005 equity offering. We used the net proceeds from our November 2005 equity offering to temporarily reduce amounts outstanding under our Multi-Year Revolving Credit Facility.

In September 2004, we borrowed $2.8 billion under our bank credit facilities (principally the 364-Day Acquisition Credit Facility) to (i) fund $655.3 million in cash payment obligations to El Paso in connection with the GulfTerra Merger; (ii) purchase $1.1 billion of GulfTerra's senior and senior subordinated notes in connection with our tender offers; and (iii) repay $962 million outstanding under GulfTerra's revolving credit facility and secured term loans. In October 2004, we issued an aggregate $2 billion in senior notes, the proceeds of which were used to reduce indebtedness outstanding under our bank credit facilities. Our repayments of debt during 2004 also reflect the use of $563.1 million of net proceeds from our May 2004 and August 2004 equity offerings to reduce indebtedness under bank credit facilities.

Net proceeds from the issuance of limited partner interests were $646.9 million in 2005 compared to $846.1 million in 2004. We issued 23,979,740 common units in 2005 and 39,683,591 common units in 2004. Net proceeds from underwritten equity offerings were $555.5 million during 2005 reflecting the sale of 21,250,000 units and $694.3 million during 2004 reflecting the sale of 34,500,000 units. We used net proceeds from these underwritten offerings to reduce debt, including the temporary repayment of indebtedness under bank credit facilities. Our distribution reinvestment program and related plan generated net proceeds of $69.7 million in 2005 and $111.6 million in 2004. We used net proceeds from these offerings for general partnership purposes. For additional information regarding our equity issuances, please read Note 15 of the Notes to Consolidated Financial Statements beginning on page 97.

Cash distributions to partners increased from $438.8 million in 2004 to $716.7 million in 2005 primarily due to an increase in common units outstanding and our quarterly cash distribution rates. We expect that future cash distributions to partners will increase as a result of our periodic issuance of common units. Cash contributions from minority interests were $39.1 million in 2005 compared to $9.6 million in 2004. These amounts relate to contributions from our joint venture partner in the Independence Hub project.

Our financing activities for 2004 include a net cash receipt of $19.4 million resulting from the settlement of forward-starting interest rate swaps.

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

*Operating activities.* Net cash provided from operating activities was $391.5 million in 2004 compared to $424.7 million in 2003. The $33.2 million decrease in net cash provided from operating activities is primarily due to (i) net income adjusted for all non-cash items and the net effects of changes in operating accounts decreased $69.3 million year-to-year primarily due to timing of cash receipts from sales and cash payments for purchases and other expenses between periods; and (ii) distributions received from unconsolidated affiliates increased $36.1 million year-to-year primarily due to distributions from GulfTerra GP, which we acquired in December 2003.

*Investing activities*. Cash used in investing activities was $941.4 million in 2004 compared to $662.1 million in 2003. We used $638.8 million in 2004 to complete the GulfTerra Merger, including our purchase of the South Texas midstream assets. Our expenditures for other asset purchases and business combinations were $724.7 million in 2004 versus $37.3 million in 2003. Investments in unconsolidated affiliates were $57.9 million in 2004 compared to $463.9 million in 2003, which includes our $425 million cash payment to El Paso to acquire GulfTerra GP in December 2003. Expenditures for growth and sustaining capital projects (net of contributions in aid of construction costs) were essentially flat year-to-year at approximately $146 million for each period.

*Financing activities*. Cash provided by financing activities was $544 million in 2004 compared to $254 million in 2003. We had net borrowings of $125.6 million during 2004 compared to net repayments of $106.8 million during 2003. As discussed under "*Financing activities*" on page 37, net borrowings during 2004 primarily reflect debt transactions associated with the GulfTerra Merger. Our borrowing transactions during 2003 include the issuance of an aggregate $850 million in senior notes and the borrowing of $425 million under a bank credit facility to purchase GulfTerra GP. Repayments of debt during 2003 reflect the use of net proceeds from debt and equity offerings completed in 2003 to reduce indebtedness under bank credit facilities, including the repayment of $1 billion outstanding under a term loan we used to acquire ownership interests in the Mid-America Pipeline System and Seminole Pipeline.

Net proceeds from the issuance of limited partner interests were $846.1 million in 2004 compared to $675.7 million in 2003. We issued 39,683,591 common units in 2004 and 29,506,303 common units in 2003. Net proceeds from underwritten equity offerings were $694.3 million during 2004 reflecting the sale of 34,500,000 units and $519.2 million during 2003 reflecting the sale of 26,622,500 units. We used net proceeds from these underwritten offerings primarily to reduce debt, including the temporary repayment of indebtedness under bank credit facilities. In addition, we received $100 million from the sale of 4,413,549 Class B special units to an affiliate of EPCO in 2003. The Class B special units converted to common units in July 2004.

Our distribution reinvestment program and related plan generated net proceeds of $111.6 million in 2004 and $60.3 million in 2003. We used net proceeds from these offerings for general partnership purposes. The year-to-year increase in net proceeds from our distribution reinvestment program is attributable to EPCO, which publicly announced in 2003 that it would reinvest approximately $140 million of its cash distributions in support of our growth objectives. This commitment extended from the distribution paid in February 2004 to the distribution paid in February 2005.

Cash distributions to partners increased from $309.9 million in 2003 to $438.8 million in 2004 primarily due to an increase in distribution-bearing units outstanding and higher cash distribution rates.

Financing activities include net cash receipts of $19.4 million in 2004 and $5.4 million in 2003 resulting from the settlement of interest rate hedging financial instruments.

## CONTRACTUAL OBLIGATIONS

The following table summarizes our significant contractual obligations at December 31, 2005. A description of each type of contractual obligation follows (dollars in thousands).

| | | Payment or Settlement due by Period | | | |
|---|---|---|---|---|---|
| **Contractual Obligations** | **Total** | **Less than 1 year** | **1-3 years** | **3-5 years** | **More than 5 years** |
| | | (2006) | (2007 – 2008) | (2009 – 2010) | Beyond 2010 |
| Scheduled maturities of long-term debt | $ 4,866,068 | | $ 517,000 | $ 1,549,068 | $ 2,800,000 |
| Estimated cash payments for interest | $ 3,160,380 | $ 271,597 | $ 518,809 | $ 455,189 | $ 1,914,785 |
| Operating lease obligations | $ 179,623 | $ 19,099 | $ 33,848 | $ 20,089 | $ 106,587 |
| Purchase obligations: | | | | | |
| Product purchase commitments: | | | | | |
| Estimated payment obligations: | | | | | |
| Natural gas | $ 1,518,016 | $ 216,690 | $ 433,973 | $ 433,380 | $ 433,973 |
| NGLs | $ 6,095,907 | $ 684,250 | $ 1,118,948 | $ 999,800 | $ 3,292,909 |
| Petrochemicals | $ 1,290,952 | $ 1,079,110 | $ 211,842 | | |
| Other | $ 87,162 | $ 31,578 | $ 44,724 | $ 10,860 | |
| Underlying major volume commitments: | | | | | |
| Natural gas (BBtus) | 127,850 | 18,250 | 36,550 | 36,500 | 36,550 |
| NGLs (MBbls) | 63,130 | 9,251 | 12,827 | 10,172 | 30,880 |
| Petrochemicals (MBbls) | 19,717 | 16,525 | 3,192 | | |
| Service payment commitments | $ 5,765 | $ 5,037 | $ 728 | | |
| Capital expenditure commitments | $ 208,575 | $ 208,575 | | | |
| Other long-term liabilities, as reflected on our Consolidated balance sheet | $ 84,486 | | $ 24,828 | $ 9,897 | $ 49,761 |
| Total | $ 17,496,934 | $ 2,515,936 | $ 2,904,700 | $ 3,478,283 | $ 8,598,015 |

### Scheduled Maturities of Long-Term Debt

We have long and short-term payment obligations under debt agreements such as the indentures governing our Operating Partnership's senior notes and the credit agreement governing our Operating Partnership's Multi-Year Revolving Credit Facility. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated. For additional information regarding our debt obligations, please read Note 14 of the Notes to Consolidated Financial Statements beginning on page 92.

### Estimated Cash Payments for Interest

We are obligated to make interest payments on our debt principal amounts outstanding. The amounts shown in the preceding table for estimated cash interest payments represent our forecast of variable and fixed interest payments to be made in connection with debt principal amounts outstanding at December 31, 2005. Our estimates of future cash interest payments include the following amounts to be paid in connection with variable interest rates: $146.6 million in total, $31.5 million for 2006, $31.2 million for 2007, $30.8 million for each of 2008 and 2009, and $22.3 million for 2010. We estimated our variable interest rate cash payments by multiplying the weighted-average variable interest rate paid during 2005 (under each of our variable rate debt obligations that were outstanding at December 31, 2005) by the debt principal amount outstanding at that date and assumed that the balance outstanding would not change until maturity.

Our estimates of cash interest payments to be paid under fixed interest rate obligations were determined by multiplying the fixed interest rate associated with each fixed rate obligation for each period that the principal would be outstanding until maturity. To the extent that we have exchanged a fixed interest rate for a variable interest rate, we have included the impact of such interest rate swap agreements in our calculations. Our internal estimates of long-term interest rates indicate that variable interest rates may exceed the fixed interest rates of the debt obligations underlying our interest rate swap agreements. If this occurs, we are responsible for payment of the excess of the current variable interest rate over the fixed interest rate of the underlying debt obligation. For conservatism, the amounts shown in the table above do not reflect any cash receipts from interest rate swap agreements (i.e., net reductions in cash outlays for interest) when the variable interest rate is less than the fixed interest rate of the underlying debt obligations.

### Operating Lease Obligations

We lease certain property, plant and equipment under non-cancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our third party operating leases with terms in excess of one year for the periods indicated. For additional information regarding our operating lease commitments, please read Note 21 of the Notes to Consolidated Financial Statements beginning on page 117.

### Purchase Obligations

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: (i) fixed or minimum quantities to be purchased; (ii) fixed, minimum or variable price provisions; and (iii) 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 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. The preceding table shows 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, 2005 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery.

*Service contract commitments*. We have long and short-term commitments to pay third party 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 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 purchased. The preceding table shows these combined amounts for the periods indicated.

### Other Long-Term Liabilities

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 preceding table represent our best estimate as to the timing of payments based on available information.

## OFF-BALANCE SHEET ARRANGEMENTS

Cameron Highway issued senior secured notes in December 2005. We secure a portion of these notes by (i) a pledge by us of our 50% partnership interest in Cameron Highway; (ii) mortgages on and pledges of certain assets related to certain rights of way and pipeline assets of an indirect wholly-owned subsidiary of ours that serves as the operator of the Cameron Highway Oil Pipeline; and (iii) letters of credit in an initial amount of $18.4 million issued by the Operating Partnership on behalf of Cameron Highway. For more information regarding Cameron Highway's senior secured notes, please read Note 14 of the Notes to Consolidated Financial Statements beginning on page 92. In addition, we have furnished $1.2 million in letters of credit on behalf of Evangeline at December 31, 2005. We currently expect that Cameron Highway will seek to amend its senior secured notes during 2006 to address delayed increases in volumes due to disruptions of production caused by Hurricanes Katrina and Rita, but we believe that such amendments will be obtained without any material adverse effect on us.

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

## RECENT ACCOUNTING DEVELOPMENTS

The following information summarizes recently issued accounting guidance that will (or may) affect our financial statements in the future:

- SFAS 123(R), "*Share-Based Payment*," eliminates the ability to account for share-based compensation transactions using Accounting Principles Board ("APB") 25 and generally requires that such transactions be accounted for using a fair value method. Historically, we have accounted for our share-based transactions using APB 25. We adopted SFAS 123(R) on January 1, 2006, which resulted in our recording a cumulative effect of a change in accounting principle of $0.3 million. During 2006, we expect to record compensation expense of $7 million associated with the fair value method of accounting for unit options, profits interests and nonvested (or restricted) units using SFAS 123(R) based on awards outstanding at January 1, 2006.

- SFAS 154, "*Accounting Changes and Error Corrections*," provides guidance on the accounting for and reporting of accounting changes and error corrections. We adopted SFAS 154 on January 1, 2006.

- Emerging Issues Task Force ("EITF") 04-13, "*Accounting for Purchases and Sale of Inventory With the Same Counterparty*," requires that two or more inventory transactions with the same counterparty be viewed as a single non-monetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. We are still evaluating this recent guidance, which is effective April 1, 2006 for our partnership, but we do not believe that our revenues or costs and expenses will be materially affected.

## 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. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts on a going forward basis. Some of these circumstances include (i) changes in laws and regulations relating to restoration and abandonment requirements; (ii) 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; (iii) changes in the useful life of an asset based on the actual known life of similar assets, changes in technology or other factors; and (iv) changes in expected salvage proceeds as a result of a change or expected change in the salvage market.

At December 31, 2005 and 2004, the net book value of our property, plant and equipment was $8.7 billion and $7.8 billion, respectively. We recorded $328.7 million, $161 million and $101 million in depreciation expense during 2005, 2004 and 2003, respectively. A significant portion of the year-to-year increase in depreciation expense between 2005 and

2004 is attributable to the property, plant and equipment assets we acquired in the GulfTerra Merger in September 2004. For additional information regarding our property, plant and equipment, please read Notes 2 and 10 of the Notes to Consolidated Financial Statements beginning on pages 59 and 77.

### Measuring Recoverability of Long-lived Assets and Equity Method Investments

In general, 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 (i) anticipated operating margins and volumes; (ii) estimated useful life of the asset or asset group; and (iii) estimated salvage values. An impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates. We recorded $1.2 million and $4.1 million for asset impairment charges in 2003 and 2004, respectively, related to NGL fractionation and storage facilities located in Mississippi.

Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value for the investment other than a temporary decline. Examples of such events include sustained 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 (i) discount rates; (ii) probabilities assigned to different cash flow scenarios; (iii) anticipated margins and volumes; and (iv) estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

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 earnings from unconsolidated affiliates during 2003.

For additional information regarding our asset impairment charges, please read Notes 2 and 11 of the Notes to Consolidated Financial Statements beginning on pages 59 and 78.

### 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 method used to value 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 customer relationship intangible assets primarily represent the customer base we acquired in connection with the GulfTerra Merger and related transactions. The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful 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 discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including (i) the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline, etc.); (ii) any legal or regulatory developments that would impact such contractual rights; and (iii) any contractual provisions that enable us to renew or extend such agreements.

If our underlying assumptions regarding the estimated useful life of an intangible asset change, then the amortization period for such asset would be adjusted accordingly. 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. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2005 and 2004, the carrying value of our intangible asset portfolio was $913.6 million and $980.6 million, respectively. We recorded $88.9 million, $33.8 million and $14.8 million in amortization expense associated with our intangible assets during 2005, 2004 and 2003, respectively. A significant portion of the year-to-year increase in amortization expense between 2005 and 2004 is attributable to the intangible assets we acquired in the GulfTerra Merger.

For additional information regarding our intangible assets, please read Notes 2 and 13 of the Notes to Consolidated Financial Statements beginning on pages 59 and 90.

### Methods We Employ to Measure the Fair Value of Goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values and is primarily comprised of $387.1 million associated with the GulfTerra Merger. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the second quarter of each fiscal year, and more frequently if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2005 and 2004, the carrying value of our goodwill was $494 million and $459.2 million, respectively.

For additional information regarding our goodwill, please read Notes 2 and 13 of the Notes to Consolidated Financial Statements beginning on pages 59 and 90.

### 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 sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), we record any necessary allowance for doubtful accounts.

Our use of certain estimates for revenues and operating costs and other expenses has increased as a result of SEC regulations that require us to submit financial information on 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 processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for the subject period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain 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 estimated for the remainder 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 to be substantially 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 federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of.  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. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves.

At December 31, 2005 and 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 5 "*Accounting for Contingencies*" and Financial Accounting Standards Board Interpretation ("FIN") 14, "*Reasonable Estimation of the Amount of a Loss*," we recorded our best estimate of these remediation activities.

### Natural Gas Imbalances

Natural gas imbalances result when customers physically deliver a larger or smaller quantity of natural gas into our pipelines than they take out. In general, we value such imbalances using a twelve-month moving average of natural gas prices, which we believe is reasonable given that the actual settlement dates for such imbalances are generally not known. As a result, significant changes in natural gas prices between reporting periods may impact our estimates.

At December 31, 2005 and 2004, our imbalance receivables were $89.4 million and $56.7 million, respectively, and are reflected as a component of accounts receivable. At December 31, 2005 and 2004, our imbalance payables were $80.5 million and $59 million, respectively, and are reflected as a component of accrued gas payables.

## SUMMARY OF RELATED PARTY TRANSACTIONS

In accordance with SFAS 57, "*Related Party Disclosures*," we have identified our material related party revenues and costs and expenses. The following table summarizes our related party transactions for the periods indicated (dollars in thousands).

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| **Revenues from consolidated operations** | | | |
| EPCO and affiliates | $ 311 | $ 2,697 | $ 4,241 |
| Shell | | 542,912 | 293,109 |
| Unconsolidated affiliates | 354,461 | 258,541 | 266,894 |
| Total | $ 354,772 | $ 804,150 | $ 564,244 |
| **Operating costs and expenses** | | | |
| EPCO and affiliates | $ 293,134 | $ 203,100 | $ 149,915 |
| Shell | | 725,420 | 607,277 |
| Unconsolidated affiliates | 23,563 | 37,587 | 43,752 |
| Total | $ 316,697 | $ 966,107 | $ 800,944 |
| **General and administrative expenses** | | | |
| EPCO and affiliates | $ 40,954 | $ 29,307 | $ 28,716 |

For additional information regarding our related party transactions identified in accordance with GAAP, please read Note 18 of the Notes to Consolidated Financial Statements beginning on page 108.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO. Our revenues from EPCO and its affiliates are primarily associated with sales of NGL products. Our expenses with EPCO are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement; and (ii) purchases of NGL products. TEPPCO is an affiliate of ours due to the common control relationship of both entities.

Historically, Shell was considered a related party under GAAP because it owned more than 10% of our limited partner interests and, prior to 2003, held a 30% membership interest in Enterprise Products GP. As a result of Shell selling a portion of its limited partner interests in us to third parties and our issuance of additional common units, Shell owned less than 10% of our common units at the beginning of 2005. Shell sold its 30% interest in Enterprise Products GP to an affiliate of EPCO in September 2003. As a result of Shell's reduced equity interest in us and its lack of control of Enterprise Products GP, Shell ceased to be considered a related party under GAAP in January 2005.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates relate to natural gas sales to a Louisiana affiliate. The majority of our expenses with unconsolidated affiliates pertain to payments to Promix for NGL transportation, storage and fractionation services.

## 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 follows (dollars in thousands):

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Total non-GAAP gross operating margin | $ 1,136,347 | $ 655,191 | $ 410,415 |
| Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income: | | | |
| Depreciation and amortization in operating costs and expenses | (413,441) | (193,734) | (115,643) |
| Retained lease expense, net in operating costs and expenses | (2,112) | (7,705) | (9,094) |
| Gain on sale of assets in operating costs and expenses | 4,488 | 15,901 | 16 |
| General and administrative costs | (62,266) | (46,659) | (37,590) |
| GAAP consolidated operating income | 663,016 | 422,994 | 248,104 |
| Other net expense, primarily interest expense | (225,178) | (153,625) | (134,406) |
| GAAP income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles | $ 437,838 | $ 269,369 | $ 113,698 |

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the "retained leases"). These subleases are part of the administrative services agreement that we executed with EPCO in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to partners' equity recorded as a general contribution to our partnership. 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.

### Cumulative Effect of Changes in Accounting Principles

Our Consolidated Statements of Operations and Comprehensive Income reflect the following cumulative effects of changes in accounting principles:

- We recorded a $4.2 million non-cash expense related to certain asset retirement obligations in 2005 due to our implementation of FIN 47 as of December 31, 2005.

- We recorded a combined $10.8 million non-cash gain in 2004 related to the impact of (i) 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 (ii) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

For additional information regarding these changes in accounting principles, including a presentation of the pro forma effects these changes would have had on our historical earnings, please read Note 8 of the Notes to Consolidated Financial Statements beginning on page 74.

### Financial Statement Reclassifications

Certain reclassifications have been made to the prior year's financial statements to conform to the current year presentation. During 2005, we changed the classification of changes in restricted cash in our Statements of Consolidated Cash Flows to present such changes as an investing activity. We previously presented such changes as an operating activity. In the accompanying Statements of Consolidated Cash Flows for the years ended December 31, 2004 and 2003, we reclassified the change in restricted cash to be consistent with our 2005 presentation. This reclassification resulted in a $12.3 million and $5.1 million increase to cash flows used in investing activities and a corresponding increase to cash provided by operating activities from the amounts previously presented for the years ended December 31, 2004 and 2003, respectively.

## 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. For additional information regarding our accounting for financial instruments, please read Note 7 of the Notes to Consolidated Financial Statements beginning on page 71.

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 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.

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 financial instrument to reestablish the economic hedge to which the closed instrument relates.

### Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess 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 Products 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 environment.

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2005 that were accounted for as fair value hedges.

| 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 7.26% | $50 million |
| Senior Notes C, 6.375% fixed rate, due Feb. 2013 | 2 | Jan. 2004 to Feb. 2013 | Feb. 2013 | 6.375% to 5.8% | $200 million |
| Senior Notes G, 5.6% fixed rate, due Oct. 2014 | 6 | 4th Qtr. 2004 to Oct. 2014 | Oct. 2014 | 5.6% to 5.24% | $600 million |
| Senior Notes K, 4.95% fixed rate, due June 2010 | 2 | Aug. 2005 to June 2010 | June 2010 | 4.95% to 4.99% | $200 million |

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

We have designated these interest rate swaps as fair value hedges under SFAS 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 the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These eleven agreements have a combined notional amount of $1.1 billion 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 London interbank offered rate ("LIBOR") (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.

The total fair value of these eleven interest rate swaps at December 31, 2005, was a liability of $19.2 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2005 and 2004 reflects a $10.8 million and $9.1 million benefit from these swap agreements, respectively.

The following table shows the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value of the underlying debt at the dates indicated (dollars in thousands). Income is not affected by changes in the fair value of these swaps; however, these swaps effectively convert the hedged portion of fixed rate debt to variable rate debt. As a result, interest expense (and related cash outlays for debt service) will increase or decrease with the change in the periodic "reset" rate associated with the respective swap. Typically, the reset rate is an agreed upon index rate published for the first day of the six-month interest calculation period.

| | Resulting | Swap Fair Value at | | |
|---|---|---|---|---|
| Scenario | Classification | December 31, 2004 | December 31, 2005 | February 1, 2006 |
| FV assuming no change in underlying interest rates | *Asset (Liability)* | $ 505 | $ (19,179) | $ (28,621) |
| FV assuming 10% increase in underlying interest rates | *Asset (Liability)* | (31,586) | (50,308) | (59,744) |
| FV assuming 10% decrease in underlying interest rates | *Asset (Liability)* | 32,596 | 11,950 | 2,503 |

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, 2005 and February 1, 2006 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 February 1, 2006 fair values ranged from approximately 4.3% to 5.2% using six-month reset periods ranging from October 2005 to October 2014.

## 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.

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 Products 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 Products 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, 2005, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of economic hedges. The fair value of our commodity financial instrument portfolio at December 31, 2005 was a liability of $0.1 million. We recorded nominal amounts of earnings from our commodity financial instruments during 2005, 2004 and 2003.

### 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 "*Contractual Obligations*" beginning on pages 39 and 117.

## Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

## Controls and Procedures

### Disclosure Controls and Procedures

Our management, including the chief executive officer ("CEO") and chief financial officer ("CFO") of Enterprise Products GP, evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting, as of December 31, 2005. This evaluation concluded that our disclosure controls and procedures, including internal controls over financial reporting, are effective to ensure that material information relating to Enterprise Products Partners is made known to management on a timely basis. Our management noted no material weaknesses in the design or operation of our internal controls over financial reporting that are likely to adversely affect our ability to record, process, summarize and report financial information. In addition, no fraud involving management or employees who have a significant role in our internal controls over financial reporting was detected.

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 our general partner, 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 Enterprise Products Partners 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 is also 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 assurance of achieving our desired control objectives, and our CEO and CFO have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance as of December 31, 2005.

### 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 Products 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 51.

*Changes in internal control over financial reporting during the fourth quarter of 2005.* There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934), or in other factors during the fourth quarter of 2005, that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

*Other internal control updates for 2005*. In accordance with SEC guidance, we opted to exclude the operations we acquired in connection with the GulfTerra Merger from the scope of our fiscal 2004 Section 404 Annual Report on Internal Controls Over Financial Reporting (the "Section 404 Annual Report"). In September 2005, we completed the integration of these operations and related computer and other data systems into our existing control environment. In February 2005, we purchased an additional 26% ownership interest in Dixie. As a result, Dixie became a majority-owned consolidated subsidiary of ours; thus, our 2005 Statement of Consolidated Operations and Comprehensive Income includes ten months of consolidated results from Dixie. Prior to its consolidation, we accounted for our investment in Dixie using the equity method. Dixie was included in our evaluations of our disclosure controls and procedures, including internal controls over financial reporting, as of December 31, 2005. Our Section 404 Annual Report for 2005 includes the operations we acquired in connection with the GulfTerra Merger and Dixie transactions.

## MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2005

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, 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 Enterprise Products Partners' management and board of directors regarding the preparation and fair presentation of published financial statements. However, our management does not represent 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 an absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of Enterprise Products Partners' internal control over financial reporting as of December 31, 2005. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission 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, 2005, Enterprise Products Partners' internal control over financial reporting is effective based on those criteria.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included in this annual report.

Our Audit and Conflicts Committee is composed of directors who are not officers or employees of Enterprise Products GP. 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 Enterprise Products Partners' 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 Enterprise Products Partners' 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 February 27, 2006.

*/s/ Robert G. Phillips*
Name: Robert G. Phillips
Title: Chief Executive Officer of our general partner, Enterprise Products GP, LLC

*/s/ Michael A. Creel*
Name: Michael A. Creel
Title: Chief Financial Officer of our general partner, Enterprise Products GP, LLC

## 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 its consolidated subsidiaries ("Enterprise Products Partners") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Enterprise Products Partners' 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 Enterprise Products Partners' 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.

In our opinion, management's assessment that Enterprise Products Partners maintained effective internal control over financial reporting as of December 31, 2005, 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, Enterprise Products Partners maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM (CONTINUED)

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet, the related statements of consolidated operation and comprehensive income, consolidated cash flows, consolidated partners' equity as of and for the year ended December 31, 2005 of Enterprise Products Partners and our report dated February 27, 2006 expressed an unqualified opinion on those financial statements.

Deloitte + Touche LLP

Houston, Texas
February 27, 2006

## 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, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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, 2005, 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 February 27, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting.

Deloitte + Touche LLP

Houston, Texas
February 27, 2006

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

| | December 31, 2005 | December 31, 2004 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | $ 42,098 | $ 24,556 |
| Restricted cash | 14,952 | 26,157 |
| Accounts and notes receivable - trade, net of allowance for doubtful accounts of $25,849 at December 31, 2005 and $24,310 at December 31, 2004 | 1,448,026 | 1,058,375 |
| Accounts receivable - related parties | 6,557 | 25,161 |
| Inventories | 339,606 | 189,019 |
| Prepaid and other current assets | 120,208 | 80,893 |
| Assets held for sale | | 36,562 |
| Total current assets | 1,971,447 | 1,440,723 |
| **Property, plant and equipment, net** | 8,689,024 | 7,831,467 |
| **Investments in and advances to unconsolidated affiliates** | 471,921 | 519,164 |
| **Intangible assets, net of accumulated amortization of $163,121 at December 31, 2005 and $74,183 at December 31, 2004** | 913,626 | 980,601 |
| **Goodwill** | 494,033 | 459,198 |
| **Deferred tax asset** | 3,606 | 6,467 |
| **Other assets** | 47,359 | 77,841 |
| Total assets | $ 12,591,016 | $ 11,315,461 |
| **LIABILITIES AND PARTNERS' EQUITY** | | |
| **Current liabilities** | | |
| Current maturities of debt | | $ 15,000 |
| Accounts payable - trade | $ 265,699 | 203,142 |
| Accounts payable - related parties | 23,367 | 41,293 |
| Accrued gas payables | 1,372,837 | 1,021,294 |
| Accrued expenses | 30,294 | 130,051 |
| Accrued interest | 71,193 | 70,335 |
| Other current liabilities | 126,881 | 104,764 |
| Total current liabilities | 1,890,271 | 1,585,879 |
| **Long-term debt** | 4,833,781 | 4,266,236 |
| **Other long-term liabilities** | 84,486 | 63,521 |
| **Minority interest** | 103,169 | 71,040 |
| **Commitments and contingencies** | | |
| **Partners' equity** | | |
| Limited partners | | |
| Common units (389,109,564 units outstanding at December 31, 2005 and 364,297,340 units outstanding at December 31, 2004 ) | 5,542,700 | 5,204,940 |
| Restricted common units (751,604 units outstanding at December 31, 2005 and 488,525 units outstanding at December 31, 2004) | 18,638 | 12,327 |
| Treasury units, at cost (427,200 units outstanding at December 31, 2004) | | (8,660) |
| General partner | 113,496 | 106,475 |
| Accumulated other comprehensive income | 19,072 | 24,554 |
| Deferred compensation | (14,597) | (10,851) |
| Total partners' equity | 5,679,309 | 5,328,785 |
| Total liabilities and partners' equity | $ 12,591,016 | $ 11,315,461 |

*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, 2005 | 2004 | 2003 |
|---|---|---|---|
| **REVENUES** | | | |
| Third parties | $ 11,902,187 | $ 7,517,052 | $ 4,782,187 |
| Related parties | 354,772 | 804,150 | 564,244 |
| Total | 12,256,959 | 8,321,202 | 5,346,431 |
| **COST AND EXPENSES** | | | |
| Operating costs and expenses | | | |
| Third parties | 11,229,528 | 6,938,229 | 4,245,833 |
| Related parties | 316,697 | 966,107 | 800,944 |
| Total operating costs and expenses | 11,546,225 | 7,904,336 | 5,046,777 |
| General and administrative costs | | | |
| Third parties | 21,312 | 17,352 | 8,874 |
| Related parties | 40,954 | 29,307 | 28,716 |
| Total general and administrative costs | 62,266 | 46,659 | 37,590 |
| Total costs and expenses | 11,608,491 | 7,950,995 | 5,084,367 |
| **EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES** | 14,548 | 52,787 | (13,960) |
| **OPERATING INCOME** | 663,016 | 422,994 | 248,104 |
| **OTHER INCOME (EXPENSE)** | | | |
| Interest expense | (230,549) | (155,740) | (140,806) |
| Dividend income from unconsolidated affiliates | | | 5,595 |
| Other, net | 5,371 | 2,115 | 805 |
| Other expense | (225,178) | (153,625) | (134,406) |
| **INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES** | 437,838 | 269,369 | 113,698 |
| Provision for income taxes | (8,362) | (3,761) | (5,293) |
| **INCOME BEFORE MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES** | 429,476 | 265,608 | 108,405 |
| Minority interest | (5,760) | (8,128) | (3,859) |
| **INCOME BEFORE CHANGES IN ACCOUNTING PRINCIPLES** | 423,716 | 257,480 | 104,546 |
| Cumulative effect of changes in accounting principles (see Note 8) | (4,208) | 10,781 | |
| **NET INCOME** | $ 419,508 | $ 268,261 | $ 104,546 |
| Cash flow financing hedges | | 19,405 | 5,354 |
| Amortization of cash flow financing hedges | (4,048) | (1,275) | 3,196 |
| Change in fair value of commodity hedges | (1,434) | 1,434 | |
| **COMPREHENSIVE INCOME** | $ 414,026 | $ 287,825 | $ 113,096 |
| | | | |
| **ALLOCATION OF NET INCOME TO:** (see Note 16) | | | |
| Limited partners' interest in net income | $ 348,512 | $ 231,153 | $ 83,817 |
| General partner interest in net income | $ 70,996 | $ 37,108 | $ 20,729 |
| | | | |
| **EARNING PER UNIT:** (see Note 20) | | | |
| Basic income per unit before changes in accounting principles | $ 0.92 | $ 0.83 | $ 0.42 |
| Basic income per unit | $ 0.91 | $ 0.87 | $ 0.42 |
| Diluted income per unit before changes in accounting principles | $ 0.92 | $ 0.83 | $ 0.41 |
| Diluted income per unit | $ 0.91 | $ 0.87 | $ 0.41 |

*See Notes to Consolidated Financial Statements*

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

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| **OPERATING ACTIVITIES** | | | |
| Net income | $ 419,508 | $ 268,261 | $ 104,546 |
| Adjustments to reconcile net income to cash flows provided by operating activities: | | | |
| Depreciation and amortization in operating costs and expenses | 413,441 | 193,734 | 115,642 |
| Depreciation and amortization in general and administrative costs | 7,184 | 1,650 | 159 |
| Amortization in interest expense | 152 | 3,503 | 12,634 |
| Equity in (income) loss of unconsolidated affiliates | (14,548) | (52,787) | 13,960 |
| Distributions received from unconsolidated affiliates | 56,058 | 68,027 | 31,882 |
| Provision for impairment of long-lived asset | | 4,114 | 1,200 |
| Cumulative effect of changes in accounting principles | 4,208 | (10,781) | |
| Operating lease expense paid by EPCO, Inc. | 2,112 | 7,705 | 9,010 |
| Other expenses paid by EPCO, Inc. | | | 436 |
| Minority interest | 5,760 | 8,128 | 3,859 |
| Gain on sale of assets | (4,488) | (15,901) | (16) |
| Deferred income tax expense | 8,594 | 9,608 | 10,534 |
| Changes in fair market value of financial instruments | 122 | 5 | (29) |
| Net effect of changes in operating accounts (see Note 23) | (266,395) | (93,725) | 120,888 |
| Net cash provided from operating activities | 631,708 | 391,541 | 424,705 |
| **INVESTING ACTIVITIES** | | | |
| Capital expenditures | (864,453) | (155,793) | (146,790) |
| Contributions in aid of construction costs | 47,004 | 8,865 | 877 |
| Proceeds from sale of assets | 44,746 | 6,882 | 212 |
| Decrease (increase) in restricted cash | 11,204 | (12,305) | (5,100) |
| Cash used for business combinations and asset purchases (see Note 12) | (326,602) | (724,661) | (37,348) |
| Acquisition of intangible asset | (1,750) | | (2,000) |
| Investments in unconsolidated affiliates | (87,342) | (57,948) | (463,876) |
| Advances to unconsolidated affiliates | (702) | (6,464) | (8,051) |
| Return of investment from unconsolidated affiliate | 47,500 | | |
| Cash used in investing activities | (1,130,395) | (941,424) | (662,076) |
| **FINANCING ACTIVITIES** | | | |
| Borrowings under debt agreements | 4,192,345 | 5,934,505 | 1,926,210 |
| Repayments of debt | (3,630,611) | (5,808,877) | (2,033,000) |
| Debt issuance costs | (9,297) | (19,911) | (8,833) |
| Distributions paid to partners | (716,699) | (438,765) | (309,918) |
| Distributions paid to minority interests | (5,724) | (6,440) | (8,113) |
| Contributions from minority interests | 39,110 | 9,585 | 5,949 |
| Contributions from general partner related to issuance of restricted units | 177 | | |
| Net proceeds from issuance of common units | 646,928 | 846,077 | 573,684 |
| Net proceeds from issuance of Class B special units | | | 102,041 |
| Treasury units reissued | | 8,394 | 646 |
| Settlement of cash flow financing hedges | | 19,405 | 5,354 |
| Cash provided by financing activities | 516,229 | 543,973 | 254,020 |
| **NET CHANGE IN CASH AND CASH EQUIVALENTS** | 17,542 | (5,910) | 16,649 |
| **CASH AND CASH EQUIVALENTS, JANUARY 1** | 24,556 | 30,466 | 13,817 |
| **CASH AND CASH EQUIVALENTS, DECEMBER 31** | $ 42,098 | $ 24,556 | $ 30,466 |

*See Notes to Consolidated Financial Statements*

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

*(See Note 15 for Unit History and Detail of Changes in Limited Partners' Equity)*
*(Dollars in thousands)*

| | Limited Partners | General Partner | Treasury units | Deferred Compensation | Accumulated Other Comprehensive Income | Total |
|---|---|---|---|---|---|---|
| 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, Inc. | 8,913 | 97 | | | | 9,010 |
| Other expenses paid by EPCO, Inc. | 433 | 3 | | | | 436 |
| Cash distributions to partners | (284,593) | (22,574) | | | | (307,167) |
| Unit option reimbursements to EPCO, Inc. | (2,721) | (30) | | | | (2,751) |
| Net proceeds from sales of common units | 567,945 | 5,739 | | | | 573,684 |
| Proceeds from issuance of Class B special units | 100,000 | 2,041 | | | | 102,041 |
| Restructuring of Enterprise Products GP ownership in our Operating Partnership | (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 |
| Net income | 231,153 | 37,108 | | | | 268,261 |
| Operating leases paid by EPCO, Inc. | 7,551 | 154 | | | | 7,705 |
| Cash distributions to partners | (394,434) | (40,440) | | | | (434,874) |
| Unit option reimbursements to EPCO, Inc. | (3,813) | (78) | | | | (3,891) |
| Net proceeds from sales of common units | 789,758 | 16,117 | | | | 805,875 |
| Proceeds from conversion of Series F2 convertible units to common units | 38,800 | 792 | | | | 39,592 |
| Proceeds from exercise of unit options | 398 | 8 | | | | 406 |
| Value of equity interests granted to complete GulfTerra Merger | 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 issued 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 |
| Net income | 348,512 | 70,996 | | | | 419,508 |
| Operating leases paid by EPCO, Inc. | 2,070 | 42 | | | | 2,112 |
| Cash distributions to partners | (630,560) | (76,752) | | | | (707,312) |
| Unit option reimbursements to EPCO, Inc. | (9,199) | (188) | | | | (9,387) |
| Net proceeds from sales of common units | 612,616 | 12,502 | | | | 625,118 |
| Proceeds from exercise of unit options | 21,374 | 436 | | | | 21,810 |
| Issuance of restricted units | 9,478 | 177 | | (9,480) | | 175 |
| Forfeiture of restricted units | (2,663) | (38) | | 2,361 | | (340) |
| Amortization of Employee Partnership awards | 1,358 | 28 | | | | 1,386 |
| Amortization of deferred compensation | | | | 3,373 | | 3,373 |
| Cancellation of treasury units | (8,915) | (182) | 8,660 | | | (437) |
| Change in fair value of commodity hedges | | | | | (1,434) | (1,434) |
| Interest rate hedging financial instruments recorded as cash flow hedges: | | | | | | |
| - Amortization of gain as component of interest expense | | | | | (4,048) | (4,048) |
| Balance, December 31, 2005 | $ 5,561,338 | $ 113,496 | $ - | $ (14,597) | $ 19,072 | $ 5,679,309 |

*See Notes to Consolidated Financial Statements*

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

### 1. Partnership Organization

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD". Unless the context requires otherwise, references to "we", "us", "our" or "Enterprise Products Partners" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. and its subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ( "EPCO"). 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 Products GP"). Enterprise Products GP is owned 100% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "EPE". The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of EPCO. We, Enterprise Products GP, Enterprise GP Holdings and EPE Holdings are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

In September 2004, we completed the "GulfTerra Merger" transactions, whereby, among other transactions, GulfTerra Energy Partners L.P. ("GulfTerra") merged with one of our wholly-owned subsidiaries. As a result of the GulfTerra Merger, GulfTerra and its subsidiaries and GulfTerra's general partner ("GulfTerra GP") became our wholly-owned subsidiaries. The GulfTerra Merger greatly expanded our asset base to include numerous natural gas and crude oil pipelines, offshore platforms and other midstream energy assets. Additionally, the GulfTerra Merger included the purchase of various midstream assets from El Paso Corporation ("El Paso") that are located in South Texas (the "STMA" acquisition).

### 2. Summary of Significant Accounting Policies

#### Allowance for Doubtful Accounts

Our allowance for doubtful accounts amount is generally determined based on specific identification and estimates of future uncollectible accounts. Our procedure for recording an allowance for doubtful accounts is based on (i) our historical experience; (ii) the financial stability of our customers; and (iii) the levels of credit granted to customers. In addition, we may also increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and those experiencing other financial difficulties. We routinely review our estimates in this area to ascertain that we have recorded sufficient reserves to cover potential losses. Our allowance for doubtful accounts was $25.8 million and $24.3 million at December 31, 2005 and 2004, respectively.

#### Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase. Our Statements of Consolidated Cash Flows are prepared using the indirect method.

#### Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all material intercompany accounts and transactions. We consolidate majority-owned subsidiaries in which we possess a controlling financial interest through a direct or indirect ownership of a majority voting interest in the subsidiary.

Investments in which we own 3% to 50% and exercise significant influence over operating and financial policies are accounted for using the equity method. If the investee is organized as a limited liability company and maintains separate ownership accounts for its members, we account for our investment using the equity method if our ownership interest is between 3% and 50%. For all other types of investees, we apply the equity method of accounting if our ownership interest is between 20% and 50%. Our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates are eliminated in consolidation to the extent such amounts are material and remain on our or our equity method investees' balance sheet in inventory or similar accounts.

If our ownership interest in an investee does not provide us with either control or significant influence over the investee, we account for the investment using the cost method.

### Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to Enterprise Products Partners but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our legal counsel evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

### Deferred Revenues

We recognize revenues when earned. Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. Please see Note 4 for additional discussion of revenues.

### Dollar Amounts

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

### Earnings Per Unit

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 Note 20 for our computation of earnings per unit for 2005, 2004 and 2003.

### Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's estimate of the ultimate cost to remediate the site. Ongoing environmental compliance costs are charged to expense as incurred. 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 merger, we assumed an environmental liability estimated at $21 million for remediation costs associated with mercury gas meters. This estimate is included in other long-term liabilities on our Consolidated Balance Sheets at December 31, 2005 and 2004.

Costs of environmental compliance and monitoring aggregated $3.3 million, $1.9 million and $1.6 million during 2005, 2004 and 2003, respectively.

## Equity Awards

Beginning January 1, 2006, we will account for our equity awards using the provisions of Statement of Financial Standards ("SFAS") 123(R), *"Share-Based Payment"*. Historically, our equity awards were accounted for using the intrinsic value method described in Accounting Principles Board Opinion ("APB") 25, "*Accounting for Stock Issued to Employees*". SFAS 123(R) requires us to recognize compensation expense related to our equity awards based on the fair value of the award at the grant date. The fair value of an equity award will be determined using option pricing models (Black-Scholes or Binomial models). Under SFAS 123(R), the fair value of an award will be amortized to earnings on a straight-line basis over the requisite service or vesting period. Previously recognized deferred compensation related to nonvested units will be reversed on January 1, 2006. See Note 5 for additional information regarding our equity awards.

*Unit options*. Under APB 25, we did not recognize any compensation expense related to unit options when the exercise price was equal to or greater than the market price of the underlying equity on the date of grant. Based on information currently available, we estimate that our compensation expense related to unit options will be $0.6 million in 2006 using the provisions of SFAS 123(R).

*Profits interests*. In connection with the initial public offering of Enterprise GP Holdings in August 2005, EPE Unit L.P. (the "Employee Partnership") was formed to allow certain employees of EPCO to increase their ownership in Enterprise GP Holdings and to serve as an incentive arrangement for such employees through a "profits interest" in the Employee Partnership. During 2005, the value of the profits interests was accounted for similar to a stock appreciation right. Based on information currently available, we estimate that our share of compensation expense related to the profits interests will be $2.2 million in 2006 using the provisions of SFAS 123(R). Using a Black-Scholes model, EPCO estimated the grant date fair value of the Class B partnership interests to be $12.5 million. For additional information regarding the Employee Partnership, see "*Relationship with EPCO and affiliates*" under Note 18.

*Nonvested units*. We issued nonvested (or restricted) units to key employees of EPCO during 2005 and 2004. In general, our nonvested common units are classified as either time-vested or performance-based. Historically, unearned compensation, representing the fair market value of such nonvested units at the date of issuance, was charged to earnings as compensation expense on a straight-line basis over the vesting period. Prior to 2006, we recognized forfeitures of nonvested units as they occurred. As a result of SFAS 123(R), we will estimate such forfeitures at grant date. Based on information currently available, we estimate that our compensation expense related to nonvested units will be $4.2 million in 2006 using the provisions of SFAS 123(R).

*Pro forma disclosures under SFAS 123*. In accordance with SFAS 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 123, "*Accounting for Stock-Based Compensation*" had been used instead of the intrinsic-value method of APB 25 to account for our equity awards. The effects of applying SFAS 123 in the following pro forma disclosure may not be indicative of future amounts as additional awards in future years are anticipated. No pro forma adjustment is required for our nonvested units since compensation expense was recognized in 2005 and 2004 based on estimated fair values of the awards.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model and various assumptions. For those unit options granted during 2005, we used the following assumptions: (i) expected life of options of seven years; (ii) risk-free interest rate of 4.2%; (iii) expected dividend yield on our units of 9.2%; and (iv) expected unit price volatility of 20%.

The fair value of the Class B partnership equity awards was also estimated on the date of grant using the Black-Scholes option pricing model and various assumptions. We used the following assumptions to estimate the fair value of these equity awards: (i) expected life of award of five years; (ii) risk-free interest rate of 4.1%; (iii) expected dividend yield on units of Enterprise GP Holdings of 3%; and (iv) expected Enterprise GP Holdings unit price volatility of 30%.

The following table shows the pro forma effects for the periods indicated.

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Reported net income | $ 419,508 | $ 268,261 | $ 104,546 |
| Additional unit option-based compensation expense estimated using fair value-based method | (708) | (932) | (1,107) |
| Reduction in compensation expense related to Employee Partnership equity awards | 1,271 | | |
| Pro forma net income | $ 420,071 | $ 267,329 | $ 103,439 |
| | | | |
| Basic earnings per unit: | | | |
| As reported | $ 0.91 | $ 0.87 | $ 0.42 |
| Pro forma | $ 0.91 | $ 0.87 | $ 0.41 |
| Diluted earnings per unit: | | | |
| As reported | $ 0.91 | $ 0.87 | $ 0.41 |
| Pro forma | $ 0.91 | $ 0.87 | $ 0.40 |

## Estimates

Preparing Enterprise Products Partners' financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect 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. Our actual results could differ from these estimates.

## Exchange Contracts

Exchanges are contractual agreements for the 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.

Receivables and payables arising from exchange transactions are satisfied with products rather than cash. When monetary consideration is required for product differentials and service costs such items are recognized on a net basis.

## Exit and Disposal Costs

Exit and disposal costs are charges associated with an exit activity not associated with business combination or with a disposal activity covered by SFAS 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 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.

## Financial Instruments

We use financial instruments such as swaps, forward and other contracts to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions. 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 instrument meets the criteria of a fair value hedge, gains and losses from the instrument will be recorded on the income statement to offset corresponding losses and gains of the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses from the instrument are recorded in other comprehensive income. Gains and losses on cash flow hedges are reclassified from other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the underlying asset. 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 133, "*Accounting for Derivative Instruments and Hedging Activities*" (as amended and interpreted). We 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 immediately recognized in earnings. See Note 7 for a further discussion of our financial instruments.

### Impairment Testing for Goodwill

Our goodwill amounts are assessed for recoverability (i) on an annual basis during the second quarter of each year or (ii) on an interim basis when impairment indicators are present. If such indicators are present (e.g., loss of a significant customer, economic obsolescence of plant assets, etc.), the fair value of the reporting unit to which the goodwill is assigned will be calculated and compared to its book value.

If the fair value of the reporting unit exceeds its book value, the goodwill amount is not considered to be impaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value, a charge to earnings is recorded to adjust the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to our goodwill for any of the periods presented. See Note 13 for a further discussion of our goodwill.

### Impairment Testing for Long-Lived Assets

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 such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values in accordance with SFAS 144. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of 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, a non-cash asset impairment charge is recognized equal to the excess of the asset's carrying value over its fair value. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm's-length transaction. We measure fair value using market prices or, in the absence of such data, appropriate valuation techniques.

We recognized non-cash asset impairment charges of $4.1 million and $1.2 million in 2004 and 2003, respectively, which are reflected as components of operating costs and expenses. No asset impairment charges were recorded in 2005.

### Impairment Testing for Unconsolidated Affiliates

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.

We had no such impairment charges during 2005 or 2004; however, a former unconsolidated affiliate recorded a $67.5 million asset impairment charge during 2003. Our share of this charge was $22.5 million, which was recorded as a reduction in equity earnings from this investee during 2003. See Note 11 for additional information regarding this non-cash charge.

### 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 our individual partners. We are organized as a pass-through entity for federal income tax purposes. As a result, our partners are individually responsible for the federal income tax on their allocable share of our taxable income. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholder's tax attributes in us.

Provision for income taxes is primarily applicable to certain federal and state tax obligations related to our Seminole Pipeline and Dixie Pipeline. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. See Note 19 for additional information regarding our provision of income taxes.

### Inventories

Our inventories primarily consist of NGL, petrochemical and natural gas volumes and are valued at the lower of average cost or market. We capitalize as a cost of inventory shipping and handling charges directly related to volumes we (i) purchase from third parties or (ii) take title to in connection with processing or other agreements. As these volumes 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 operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 9 for a further discussion of our inventories.

Costs and expenses, as shown on our Statements of Consolidated Operations and Comprehensive Income, include cost of sales related to inventories. Our consolidated cost of sales amounts were $10.3 billion, $7.2 billion and $4.5 billion during 2005, 2004 and 2003, respectively.

### Minority Interest

Minority interest represents third party ownership interests in the net assets of our subsidiaries that are joint ventures. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of our own, with any third party investor's interest in our consolidated balance amounts shown as minority interest. Minority interest expense reflects the allocation of joint venture earnings to third party investors. Distributions to and contributions from minority interests represent cash payments and cash contributions, respectively, from such third party investors.

At December 31, 2005, our joint venture subsidiaries were Seminole Pipeline Company ("Seminole"), Tri-States Pipeline LLC ("Tri-States"), Independence Hub, LLC ("Independence Hub"), Dixie Pipeline Company ("Dixie") and Belle Rose NGL Pipeline LLC ("Belle Rose"). At December 31, 2004, our joint venture subsidiaries included those listed for 2005 and Mapletree, LLC and E-Oaktree, LLC. We purchased the remaining 2% membership interests in Mapletree, LLC and E-Oaktree, LLC in June 2005 for $25 million. This acquisition increased our indirect ownership interests in the Mid-America Pipeline System to 100% and the Seminole Pipeline to 90%.

### Natural Gas Imbalances

Natural gas imbalances result when a customer injects more or less gas into a pipeline than they withdraw. In general, we value our imbalance receivables and payables using a twelve-month moving average of natural gas prices. We believe this valuation method is appropriate given that 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, 2005 and 2004, our imbalance receivables were $89.4 million and $56.7 million, respectively, and are reflected as a component of "Accounts receivable – trade" on our Consolidated Balance Sheets. At December 31, 2005 and 2004, our imbalance payables were $80.5 million and $59 million, respectively, and are reflected as a component of "Accrued gas payables" on our Consolidated Balance Sheets.

### Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations from the respective period. Depreciation is recorded over the estimated useful lives of the related assets primarily using the straight-line method for financial statement purposes. We use other depreciation methods (generally accelerated) for tax purposes where appropriate. See Note 10 for additional information regarding our property, plant and equipment.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from its acquisition, construction, development and/or normal operation. We record a liability for AROs when incurred and capitalize an increase in the carrying value 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 its useful life. We will either settle our ARO obligations at the recorded amount or incur a gain or loss upon settlement.

### Reclassifications

Certain reclassifications have been made to the financial statements of prior years to conform to the current year presentation. These reclassifications had no effect on reported results of operations or financial position for 2004 and 2003.

In 2005, we reclassified changes in restricted cash balances (as shown on our Statements of Cash Flows) from operating activities to investing activities in response to best accounting practices. In order to conform the Statements of Cash Flows for 2004 and 2003 to the current period presentation, we reclassified the $12.3 million and $5.1 million increases in restricted cash balances during 2004 and 2003, respectively, from operating activities to investing activities.

### Restricted Cash

Restricted cash represents amounts held by a brokerage firm in connection with (i) our commodity financial instruments portfolio and (ii) physical natural gas purchases made on the NYMEX exchange.

### Revenue Recognition

See Note 4 for information regarding our revenue recognition policies.

### Start-Up and Organization Costs

Start-up costs and organization costs are expensed as incurred. Start-up costs are defined as one-time activities related to opening a new facility, introducing a new product or service, conducting activities in a new territory, pursuing a new class of customer, initiating a new process in an existing facility or some new operation. Routine ongoing efforts to improve existing facilities, products or services are not start-up costs. Organization costs include legal fees, promotional costs and similar charges incurred in connection with the formation of a business.

## 3. Recent Accounting Developments

The following information summarizes recently issued accounting guidance that will (or may) affect our financial statements in the future:

- SFAS 123(R), "*Share-Based Payment*," eliminates the ability to account for share-based compensation transactions using APB 25 and generally requires instead that such transactions be accounted for using a fair value method. Historically, we have accounted for our share-based transactions using APB 25. We adopted SFAS 123(R) on January 1, 2006, which resulted in our recording a cumulative effect of a change in accounting principle of $0.3 million. During 2006, we expect to record compensation expense of $7 million associated with the fair value method of accounting for unit options, profits interests and nonvested (or restricted) units using SFAS 123(R) based on awards outstanding at January 1, 2006.

- SFAS 154, "*Accounting Changes and Error Corrections*," provides guidance on the accounting for and reporting of accounting changes and error corrections. We adopted SFAS 154 on January 1, 2006.

- Emerging Issues Task Force ("EITF") 04-13, "*Accounting for Purchases and Sale of Inventory With the Same Counterparty*," requires that two or more inventory transactions with the same counterparty should be viewed as a single nonmonetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. We are still evaluating this recent guidance, which is effective April 1, 2006 for our partnership, but we do not believe that our revenues or costs and expenses will be materially affected.

## 4. Revenue Recognition

We recognize revenue 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. We generally do not take title to products gathered, transported or processed unless noted below. The following information summarizes our revenue recognition policies by business segment:

### NGL Pipelines & Services

In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds, fee-based contracts, hybrid contracts (mixed percent-of-liquids and fee-based) and keepwhole contracts. 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. 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. Under a percent-of-proceeds contract, we share in the proceeds generated from the producer's sale of the mixed NGLs we extract on their behalf. Revenue is recognized under percent-of-proceeds arrangements when the extracted NGLs are delivered and sold to customers. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue in the period the services are provided.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and purchases from third parties on the open market. These sales contracts may also include forward product sales contracts. Revenues from these sales contracts are recognized when the NGLs are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Under our NGL pipeline transportation contracts, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC").

Under our NGL and related product storage contracts, we collect a fee based on the number of days a customer has 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 terminalling contracts (applicable to our import and export operations) are recorded in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. In our export operations, we may also record revenues related to demand fees we charge customers who reserve to use our export facilities and later fail to do so. We recognize such demand fee revenue when the customer fails to utilize our facilities as required by contract.

In our NGL fractionation business, we enter into fee-based arrangements and percent-of-liquids contracts. Under our fee-based arrangements, we recognize revenue in the period the services are provided. These fee-based arrangements typically include a base-processing fee (typically in cents per gallon) that is subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At certain of our NGL fractionation facilities, we generate revenues using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the NGLs fractionated for customers as payment for our services. We recognize revenue from such arrangements when the NGLs we retain are sold and delivered to customers.

### Onshore Natural Gas Pipelines & Services

Certain of our onshore natural gas pipelines generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by 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.

In addition, 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 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: (i) fixed monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage of the storage facilities; and (ii) storage fees per unit of volume stored at the facilities. Revenues from demand payments are recognized throughout the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

### Offshore Pipelines & Services

Our revenues from offshore natural gas pipelines are derived from fee-based contracts and are typically based on transportation fees per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. We recognize revenue when volumes have been physically delivered for the customer through the pipeline.

The majority of our revenues from offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points along 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 same index-based price. Net revenue recognized from such arrangements is based on the price differential per unit of volume (typically in barrels) multiplied by the volume delivered. We recognize revenues from such arrangements when we complete the delivery of crude oil to the purchaser.

In addition, certain of our offshore crude oil pipelines generate revenues based upon a gathering fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. We recognize revenues from these gathering contracts when we complete delivery of the crude oil for the producer.

Revenues from offshore platform services generally consist of demand fees and commodity charges. Demand fees represent fixed-fees charged to customers who use our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. 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.

### 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 in the period the services are provided. 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 propylene fractionation and isomerization operations.

Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our processing activities and purchases from third parties on the open market. Revenues from these sales contracts are recognized when the products are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

## 5. Accounting for Equity Awards

As discussed in Note 2, we will account for our equity awards using the provisions of SFAS 123(R) beginning January 1, 2006. See Notes 2 and 3 for information regarding our adoption of this new accounting guidance. The following discussion pertains to our historical practice of accounting for equity awards using the intrinsic value method described in APB 25.

### Unit Options

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 has not granted the right to receive distributions on unvested unit options. EPCO purchases common units to fund its obligations under the 1998 Plan at fair value either in the open market or from us.

Historically, we accounted for unit options using the intrinsic value method described in APB 25. The exercise price of each option granted was equivalent to or greater than the market price of the underlying equity 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.

When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee. Our option-related reimbursements were $9.2 million, $3.8 million and $2.7 million in 2005, 2004 and 2003, respectively.

### 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 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 |
| Granted | 530,000 | 26.49 |
| Exercised | (826,000) | 14.77 |
| Forfeited | (85,000) | 24.73 |
| **Outstanding at December 31, 2005** | 2,082,000 | 22.16 |
| **Options exercisable at:** | | |
| December 31, 2003 | 509,000 | $ 9.68 |
| December 31, 2004 | 1,154,000 | $ 14.65 |
| December 31, 2005 | 727,000 | $ 19.19 |

The following table provides additional information regarding our unit options outstanding at December 31, 2005:

| | | | | Options Exercisable at December 31, 2005 | |
|---|---|---|---|---|---|
| Range of Strike Prices | Options Outstanding at December 31, 2005 | Weighted Average Remaining Contractual Life (in Years) | Weighted Average Strike Price | Number Exercisable at December 31, 2005 | Weighted Average Strike Price |
| $9.00 - $12.56 | 118,000 | 4.41 | $ 10.68 | 118,000 | $ 10.68 |
| $15.93 - $17.63 | 225,000 | 5.14 | 16.47 | 225,000 | 16.47 |
| $20.00 - $24.73 | 1,249,000 | 7.84 | 22.57 | 384,000 | 23.40 |
| $26.47 - $26.95 | 490,000 | 9.57 | 26.49 | | n/a |
| | 2,082,000 | | | 727,000 | |

The weighted-average fair value of options granted during 2005, 2004 and 2003 was $1.35, $2.26 and $2.17 per option, respectively.

### Employee Partnership

In connection with the initial public offering of Enterprise GP Holdings in August 2005, the Employee Partnership was formed to serve as an incentive arrangement for certain employees of EPCO through a "profits interest" in the Employee Partnership. During 2005, the value of the profits interests was accounted for similar to a stock appreciation right. For additional information regarding the Employee Partnership, see "*Relationship with EPCO and affiliates*" under Note 18.

EPCO accounted for this share-based compensation arrangement under APB 25 until it adopted SFAS 123(R) on January 1, 2006. Under APB 25, the intrinsic value of the Class B limited partnership interest was accounted for similar to a stock appreciation right. EPCO's compensation expense related to this share-based compensation arrangement is allocated to us and other affiliates of EPCO pursuant to an administrative services agreement. For the year ended December 31, 2005, we were allocated $2 million of non-cash compensation expense associated with this share-based compensation arrangement.

## Nonvested Units

We began issuing nonvested (or restricted) common units to key employees of EPCO and directors of our general partner in 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, was 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. However, at December 31, 2005, we believe it is probable that financial performance will be met. Unearned compensation, representing the fair market value of these units at the date of issuance, was 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. Performance-based restricted units are counted as outstanding units for dilutive earnings per unit purposes only.

At December 31, 2005, we had 751,604 restricted common units outstanding, which includes 724,454 time-vested restricted units and 27,150 performance-based restricted units. Unearned compensation attributable to restricted units was $14.6 million and $10.9 million at December 31, 2005 and 2004, respectively. We amortized $3.4 million and $0.8 million of such compensation expense to earnings in 2005 and 2004, respectively.

## 6. Employee Benefit Plans

During the first quarter of 2005, we acquired a controlling ownership interest in Dixie Pipeline Company ("Dixie"), which resulted in Dixie becoming a consolidated subsidiary of ours. Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie's employee benefit plans to our consolidated financial position, results of operations and cash flows, our discussion is limited to the following:

*Defined contribution plan.* Dixie contributed $0.3 million to its company-sponsored defined contribution plan during 2005.

*Pension and post-retirement benefit plans.* Dixie's pension plan is a non-contributory defined benefit plan that provides for the payment of benefits to retirees based on their age at retirement, years of service and average compensation. Dixie's post-retirement benefit plan also provides medical and life insurance to retired employees. The medical plan is contributory and the life insurance plan is non-contributory. Dixie employees hired after July 1, 2004 are not eligible for pension and other benefit plans after retirement.

The following table shows Dixie's benefit obligations, fair value of plan assets, unfunded liabilities and accrued benefit liabilities at December 31, 2005.

| | Pension Plan | Post-retirement Plan |
|---|---|---|
| Projected benefit obligation | $ 9,434 | $ 4,505 |
| Accumulated benefit obligation | 7,023 | 4,505 |
| Fair value of plan assets | 4,954 | |
| Unfunded liability | 4,480 | 4,505 |
| Accrued benefit liability | 4,348 | 4,747 |

Dixie's net pension and post-retirement benefit costs for 2005 were $0.6 million and $0.2 million, respectively. Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining net periodic benefit costs for 2005 were as follows: (i) discount rate of 5.75%; (ii) expected long-term return on plan assets of 7%; (iii) rate of compensation increase of 4%; and (iv) a medical trend rate of 7% in 2005 grading to an ultimate trend rate of 5% in 2007 and later years. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2005 were as follows: (i) discount rate of 5.5%; (ii) expected long-term rate of return on assets of 7%; (iii) rate of compensation increase of 4%; and (iv) a medical trend rate of 6% for 2006 grading to an ultimate trend of 5% for 2007 and later years.

Future benefits expected to be paid from Dixie's pension and post-retirement plans are as follows for the periods indicated:

| | Pension Plan | Post-retirement Plan |
|---|---|---|
| 2006 | $ 448 | $ 272 |
| 2007 | 682 | 289 |
| 2008 | 558 | 283 |
| 2009 | 800 | 302 |
| 2010 | 832 | 330 |
| 2011 through 2015 | 4,804 | 1,883 |
| Total | $ 8,124 | $ 3,359 |

## 7. 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 133, (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.

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 financial instrument to reestablish the economic hedge to which the closed instrument relates.

## Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess 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 Products 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 environment.

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2005 that were accounted for as fair value hedges.

| 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 7.26% | $50 million |
| Senior Notes C, 6.375% fixed rate, due Feb. 2013 | 2 | Jan. 2004 to Feb. 2013 | Feb. 2013 | 6.375% to 5.8% | $200 million |
| Senior Notes G, 5.6% fixed rate, due Oct. 2014 | 6 | 4th Qtr. 2004 to Oct. 2014 | Oct. 2014 | 5.6% to 5.24% | $600 million |
| Senior Notes K, 4.95% fixed rate, due June 2010 | 2 | Aug. 2005 to June 2010 | June 2010 | 4.95% to 4.99% | $200 million |

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

We have designated these interest rate swaps as fair value hedges under SFAS 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 the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These eleven agreements have a combined notional amount of $1.1 billion 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 London interbank offered rate ("LIBOR") (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.

The total fair value of these eleven interest rate swaps at December 31, 2005, was a liability of $19.2 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2005 and 2004 reflects a $10.8 million and $9.1 million benefit from these swap agreements, respectively.

During the first nine months of 2004, we entered into eight forward starting interest rate swaps having an aggregate notional value of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these financial instruments was to effectively hedge the underlying U.S. treasury rate related to our issuance of $2 billion in principal amount of fixed rate debt. In October 2004, the Operating Partnership issued $2 billion of private placement debt under Senior Notes E through H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS 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 following table shows the notional amount covered by each forward starting swap and the cash gain (loss) associated with each swap upon settlement:

| 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 |

The net gain of $19.4 million from these settlements will be reclassified from Accumulated Other Comprehensive Income ("AOCI") to reduce interest expense over the life of the associated debt. We reclassified $4 million and $1.3 million from AOCI during 2005 and 2004, respectively, which reduced the amount of interest expense we recognized.

### 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 Products 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 Products 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, 2005, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of economic hedges. The fair value of our commodity financial instrument portfolio at December 31, 2005 was a liability of $0.1 million. We recorded nominal amounts of earnings from our commodity financial instruments during 2005, 2004 and 2003.

### Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed rate debt are 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 interest rate and commodity hedging portfolios were developed using available market information and appropriate valuation techniques.

The following table presents the estimated fair values of our financial instruments at the dates indicated:

| Financial Instruments | December 31, 2005 Carrying Value | December 31, 2005 Fair Value | December 31, 2004 Carrying Value | December 31, 2004 Fair Value |
|---|---|---|---|---|
| Financial assets: | | | | |
| Cash and cash equivalents | $ 57,050 | $ 57,050 | $ 50,713 | $ 50,713 |
| Accounts receivable | 1,454,583 | 1,454,583 | 1,083,536 | 1,083,536 |
| Commodity financial instruments (1) | 1,114 | 1,114 | 3,904 | 3,904 |
| Interest rate hedging financial instruments (2) | | | 505 | 505 |
| Financial liabilities: | | | | |
| Accounts payable and accrued expenses | 1,763,390 | 1,763,390 | 1,466,115 | 1,466,115 |
| Fixed rate debt (principal amount) | 4,359,068 | 4,395,110 | 3,725,469 | 3,922,459 |
| Variable rate debt | 507,000 | 507,000 | 563,229 | 563,229 |
| Commodity financial instruments (1) | 1,167 | 1,167 | 3,685 | 3,685 |
| Interest rate hedging financial instruments (2) | 19,179 | 19,179 | | |

(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 have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

## 8. Cumulative Effect of Changes in Accounting Principles

In 2005 and 2004, we recorded various amounts related to the cumulative effect of changes in accounting principles, including (i) $4.2 million in December 2005 related to our implementation of FIN 47; and (ii) a combined $10.8 million during 2004 related to changing a subsidiary's accounting method for planned major maintenance activities and the method we use to account for our investment in Venice Energy Services Company, LLC ("VESCO").

*Implementation of FIN 47*. In December 2005, we adopted Financial Accounting Standards Board ("FIN") 47, which required us to record a liability for asset retirement obligations ("AROs") in which the timing and/or amount of settlement of the obligation are uncertain. These conditional asset retirement obligations were not addressed in SFAS 143, which we adopted on January 1, 2003. We recorded a cumulative effect of change in accounting principle of $4.2 million in connection with our implementation of FIN 47, which represents the depreciation and accretion expense we would have recognized had we recorded these conditional asset retirement obligations when incurred. For additional information regarding our asset retirement obligations, see Note 10.

*BEF major maintenance costs*. In January 2004, our Belvieu Environmental Fuels ("BEF") subsidiary changed its accounting method for planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred approach. BEF 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. This change conformed BEF's accounting policy for such costs to that followed by our other operations which use the expense-as-incurred approach. As such, we believe the change is to a method that is preferable under the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

*Investment in VESCO*. In July 2004, we changed the method we use to account for our investment in VESCO from the cost method to the equity method in accordance with EITF 03-16, "*Accounting for Investments in Limited Liability Companies*". EITF 03-16 requires partnership-type accounting for investments in limited liability companies that have separate ownership accounts for each investor. As a result of EITF 03-16, 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% to 5%) than the traditional 20% threshold applied under APB 18, "*The Equity Method of Accounting for Investments in Common Stock*".

Prior to adopting EITF 03-16, 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 we received cash distributions from them. Our cumulative effect adjustment for EITF 03-16 represents (i) equity earnings from VESCO that would have been recorded had we used the equity method of accounting prior to 2004 less (ii) the dividend income we recorded from VESCO prior to 2004 using the cost method. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

For the periods indicated, the following table shows unaudited pro forma net income for the years ended December 31, 2005, 2004 and 2003, assuming the three accounting changes noted above were applied retroactively to January 1, 2003.

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| **Pro forma income statement amounts:** | | | |
| Historical net income | $ 419,508 | $ 268,261 | $ 104,546 |
| Adjustments to derive pro forma net income: | | | |
| *Effect of implementation of FIN 47* | | | |
| Remove cumulative effect of change in accounting principle recorded in December 2005 | 4,208 | | |
| Record depreciation and accretion expense associated with conditional asset retirement obligations | (735) | (373) | (246) |
| *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 |
| Record equity in (income) losses from BEF calculated using new method of accounting for major maintenance costs | | | (31,800) |
| Remove cumulative effect of change in accounting principle recorded in January 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 in July 2004 | | (3,768) | |
| Remove historical dividend income recorded from VESCO | | (2,136) | (5,595) |
| Record equity earnings from VESCO | | 2,429 | 5,133 |
| Pro forma net income | 422,981 | 259,738 | 103,546 |
| Enterprise Products GP interest | (71,066) | (36,938) | (20,705) |
| Pro forma net income available to limited partners | $ 351,915 | $ 222,800 | $ 82,841 |
| **Pro forma per unit data (basic):** | | | |
| Historical units outstanding | 381,857 | 265,370 | 199,915 |
| Per unit data: | | | |
| As reported | $ 0.91 | $ 0.87 | $ 0.42 |
| Pro forma | $ 0.92 | $ 0.84 | $ 0.41 |
| **Pro forma per unit data (diluted):** | | | |
| Historical units outstanding | 382,963 | 266,045 | 206,367 |
| Per unit data: | | | |
| As reported | $ 0.91 | $ 0.87 | $ 0.41 |
| Pro forma | $ 0.92 | $ 0.84 | $ 0.40 |

## 9. Inventories

Our inventory amounts were as follows at the dates indicated:

| | December 31, | |
|---|---|---|
| | 2005 | 2004 |
| Working inventory | $ 279,237 | $ 171,485 |
| Forward-sales inventory | 60,369 | 17,534 |
| Total inventory | $ 339,606 | $ 189,019 |

A general description of our inventories is as follows:

- Our regular trade (or "working") inventory is primarily 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 Oil Price Information Service ("OPIS") and Chemical Market Associates, Inc. ("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.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes and other related costs including terminal and storage fees, vessel inspection and demurrage charges and processing costs.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 4), these volumes are valued at market-related prices during the month in which they are acquired. As with inventory volumes we purchase for cash, we capitalize as a component of inventory those ancillary costs (e.g., freight-in and other handling and processing charges) incurred in connection with volumes obtained through such 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 and generally affect our segment operating results in the following manner:

- NGL inventory write downs are recorded as a cost of our NGL marketing activities within our NGL Pipelines & Services business segment;

- Natural gas inventory write downs are recorded as a cost of our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment; and

- Petrochemical inventory write downs are recorded as a cost of our petrochemical marketing activities or octane additive production business within our Petrochemical Services business segment, as applicable.

For the years ended December 31, 2005, 2004 and 2003, we recognized LCM adjustments of approximately $21.9 million, $9.4 million and $16.9 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 offset. See Note 7 for a description of our commodity hedging activities.

## 10. Property, Plant and Equipment

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

| | Estimated Useful Life in Years | At December 31, 2005 | 2004 |
|---|---|---|---|
| Plants and pipelines (1) | 5-35 (5) | $ 8,209,580 | $ 7,691,197 |
| Underground and other storage facilities (2) | 5-35 (6) | 549,923 | 531,394 |
| Platforms and facilities (3) | 23-31 | 161,807 | 162,645 |
| Transportation equipment (4) | 3-10 | 24,939 | 7,240 |
| Land | | 38,757 | 29,142 |
| Construction in progress | | 854,595 | 230,375 |
| Total | | 9,839,601 | 8,651,993 |
| Less accumulated depreciation | | 1,150,577 | 820,526 |
| Property, plant and equipment, net | | $ 8,689,024 | $ 7,831,467 |

(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 include 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, 2005, 2004 and 2003 was $328.7 million, $161 million and $101 million, respectively. A significant portion of the year-to-year increase in depreciation expense between 2005 and 2004 is attributable to assets we acquired in connection with the GulfTerra Merger, which was completed on September 30, 2004.

We capitalized $22 million, $2.8 million and $1.6 million of interest associated with construction projects during 2005, 2004 and 2003, respectively.

*Asset retirement obligations*. We have recorded asset retirement obligations related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our asset retirement obligations primarily result from (i) right-of-way agreements associated with our pipeline operations; (ii) leases of plant sites; and (iii) regulatory requirements triggered by the abandonment or retirement of certain underground storage assets and offshore facilities. In addition, our asset retirement obligations may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

Previously, we recorded asset retirement obligations associated with the future retirement and removal activities of certain offshore assets located in the Gulf of Mexico. In December 2005, we adopted FIN 47 and recorded an additional $10.1 million in connection with conditional asset retirement obligations. The cumulative effect of this change in accounting principle for years prior to 2005 was a non-cash charge of $4.2 million. None of our assets are legally restricted for purposes of settling asset retirement obligations.

The following table presents information regarding our asset retirement obligations since December 31, 2004.

| | |
|---|---|
| Asset retirement obligation liability balance, December 31, 2004 | $ 6,236 |
| Adoption of FIN 47 for conditional obligations | 10,076 |
| Accretion expense | 483 |
| Asset retirement obligation liability balance, December 31, 2005 | $ 16,795 |

Property, plant and equipment at December 31, 2005 and 2004 includes $0.9 million and $0.2 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. Also, based on information currently available, we estimate that accretion expense will approximate $1.4 million for 2006, $1.1 million for 2007, $1.2 million for 2008, $1.3 million for 2009 and $1.4 million for 2010.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2005 and 2004 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

## 11. Investments in and Advances to Unconsolidated Affiliates

Our investments in and advances to our unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of our business segments, see Note 17. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

| | Ownership Percentage at December 31, 2005 | Investments in and Advances to Unconsolidated Affiliates at December 31, 2005 | Investments in and Advances to Unconsolidated Affiliates at December 31, 2004 |
|---|---|---|---|
| NGL Pipelines & Services: | | | |
| Dixie Pipeline Company ("Dixie") (1) | | | $ 32,514 |
| Venice Energy Services Company, LLC ("VESCO") | 13.1% | $ 39,689 | 38,437 |
| Belle Rose NGL Pipeline LLC ("Belle Rose")(2) | | | 10,172 |
| K/D/S Promix LLC ("Promix") | 50% | 65,103 | 65,748 |
| Baton Rouge Fractionators LLC ("BRF") | 32.3% | 25,584 | 27,012 |
| Onshore Natural Gas Pipelines & Services: | | | |
| Evangeline (3) | 49.5% | 3,151 | 2,810 |
| Coyote Gas Treating, LLC ("Coyote") | 50% | 1,493 | 2,441 |
| Offshore Pipelines & Services: | | | |
| Poseidon Oil Pipeline, L.L.C. ("Poseidon") | 36% | 62,918 | 63,944 |
| Cameron Highway Oil Pipeline Company ("Cameron Highway") (4) | 50% | 58,207 | 114,354 |
| Deepwater Gateway, L.L.C. ("Deepwater Gateway") (5) | 50% | 115,477 | 56,527 |
| Neptune Pipeline Company, L.L.C. ("Neptune") | 25.67% | 68,085 | 72,052 |
| Nemo Gathering Company, LLC ("Nemo") | 33.92% | 12,157 | 12,586 |
| Petrochemical Services: | | | |
| Baton Rouge Propylene Concentrator, LLC ("BRPC") | 30% | 15,212 | 15,617 |
| La Porte (6) | 50% | 4,845 | 4,950 |
| Total | | $ 471,921 | $ 519,164 |

(1) We acquired an additional 20% ownership interest in Dixie in January 2005 and an additional 26.1% ownership interest in February 2005. As a result of these acquisitions, Dixie became a consolidated subsidiary.

(2) We acquired an additional 41.7% ownership interest in Belle Rose in June 2005. As a result of this acquisition, Belle Rose became a consolidated subsidiary.

(3) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.

(4) Cameron Highway began deliveries of Gulf of Mexico crude oil production to major refining markets along the Texas Gulf Coast during the first quarter of 2005. In June 2005, we received a $47.5 million return of our investment in Cameron Highway due to the refinancing of Cameron Highway's project debt. For additional information regarding the refinancing of Cameron Highway's debt, please read Note 14.

(5) In March 2005, we contributed $72 million to Deepwater Gateway to fund our share of the repayment of its $144 million term loan. For additional information regarding Deepwater Gateway's repayment of its term loan, please read Note 14.

(6) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

On occasion, the price we pay to acquire an ownership interest in an investee exceeds the carrying value of the historical net assets of the investee we are purchasing. Such excess amounts (or "excess costs") are a component of our investments in and advances to unconsolidated affiliates.

At December 31, 2005, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Nemo included excess cost amounts. At the time of purchase, an analysis of each of these investments indicated that such excess cost amounts were either (i) attributable to an increase in the fair value of tangible or qualifying intangible assets owned by each entity over its historical carrying values for such assets or (ii) unattributable and deemed to be goodwill.

To the extent that we attribute all or a portion of an excess cost amount to an increase in the fair value of assets, we amortize such excess cost 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, 2005, our investments in and advances to unconsolidated affiliates included $48.1 million of excess cost amounts, all of which were attributed to increases in fair value of the underlying assets of the investees. At December 31, 2004, our excess cost amounts totaled $83.6 million, of which $74.3 million was attributed to increases in fair value of the underlying assets and the remainder to goodwill. The decrease in total excess cost during 2005 is due to the consolidation of Dixie and amortization of excess cost amounts attributable to the fair value of underlying assets. Equity earnings from unconsolidated affiliates were reduced by $2.3 million, $1.9 million and $1.6 million during 2005, 2004 and 2003, respectively, due to the amortization of excess cost amounts.

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

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| NGL Pipelines & Services: | | | |
| Dixie (1) | $ 1,103 | $ 1,273 | $ 1,323 |
| VESCO (2) | 1,412 | 6,132 | |
| Belle Rose (1) | (151) | (402) | (55) |
| Promix | 1,876 | 859 | 2,106 |
| BRF | 1,313 | 2,190 | 832 |
| Tri-States NGL Pipeline LLC ("Tri-States") (1) | | (154) | 1,542 |
| Wilprise Pipeline Company, LLC ("Wilprise") (1) | | | 276 |
| EPIK (1,3) | | | 1,818 |
| Onshore Natural Gas Pipelines & Services: | | | |
| Evangeline | 331 | 231 | 131 |
| Coyote | 2,053 | 541 | |
| Offshore Pipelines & Services: | | | |
| Poseidon | 7,279 | 2,509 | |
| Cameron Highway (4) | (15,872) | (461) | |
| Deepwater Gateway | 10,612 | 3,562 | |
| Neptune | 2,019 | (1,852) | 1,014 |
| Nemo | 1,774 | 1,628 | 1,268 |
| Starfish Pipeline Company, LLC ("Starfish") (5) | 313 | 3,473 | 3,279 |
| Petrochemical Services: | | | |
| BRPC | 1,224 | 1,943 | 1,198 |
| La Porte | (738) | (710) | (698) |
| Belvieu Environmental Fuels, L.P. ("BEF") (1) | | | (27,864) |
| Olefins Terminal Corporation ("OTC") (1) | | | (77) |
| Other: | | | |
| GulfTerra GP (6) | | 32,025 | (53) |
| Total | $ 14,548 | $ 52,787 | $ (13,960) |

(1) 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; Tri-States, April 2004; Dixie, February 2005; and Belle Rose, June 2005.

(2) As a result of adopting EITF 03-16 during 2004, we changed from the cost method to the equity method of accounting with respect to our investment in VESCO. See Note 8 for information regarding this accounting change.

(3) EPIK refers to EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively.

(4) Equity earnings from Cameron Highway for the year ended December 31, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway's project debt (see Note 14).

(5) We were required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish. On March 31, 2005, we sold this asset to a third party.

(6) In connection with the GulfTerra Merger (see Note 12), GulfTerra GP became a wholly owned consolidated subsidiary of ours 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.

## NGL Pipelines & Services

At December 31, 2005, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

*VESCO*. We own a 13.1% interest in VESCO, which owns a natural gas processing and NGL fractionation facility and related storage and pipeline assets located in south Louisiana. 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 8).

*Promix*. We own a 50% interest in Promix, which owns an NGL fractionation facility and related storage and pipeline assets located in south Louisiana.

*BRF*. We own an approximate 32.3% interest in BRF, which owns an NGL fractionation facility located in south Louisiana.

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

| | At December 31, | |
|---|---|---|
| | **2005** | **2004** |
| **BALANCE SHEET DATA:** | | |
| Current assets | $ 72,784 | $ 93,017 |
| Property, plant and equipment, net | 328,270 | 348,168 |
| Other assets | 12,471 | 13,017 |
| Total assets | $ 413,525 | $ 454,202 |
| Current liabilities | $ 32,886 | $ 72,427 |
| Other liabilities | 7,343 | 6,882 |
| Combined equity | 373,296 | 374,893 |
| Total liabilities and combined equity | $ 413,525 | $ 454,202 |

| | For Year Ended December 31, | | |
|---|---|---|---|
| | **2005** | **2004** | **2003** |
| **INCOME STATEMENT DATA:** | | | |
| Revenues | $ 207,775 | $ 244,521 | $ 258,939 |
| Operating income | 6,696 | 40,259 | 34,630 |
| Net income | 6,509 | 40,355 | 34,500 |

## Onshore Natural Gas Pipelines & Services

At December 31, 2005, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

*Evangeline*. We own an approximate 49.5% aggregate interest in Evangeline, which owns a natural gas pipeline system located in south Louisiana.

*Coyote*. We own 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 current unconsolidated affiliates are summarized below.

| | At December 31, 2005 | At December 31, 2004 |
|---|---|---|
| **BALANCE SHEET DATA:** | | |
| Current assets | $ 41,674 | $ 21,652 |
| Property, plant and equipment, net | 36,380 | 38,821 |
| Other assets | 28,732 | 35,149 |
| Total assets | $ 106,786 | $ 95,622 |
| | | |
| Current liabilities | $ 72,441 | $ 24,365 |
| Other liabilities | 32,737 | 37,210 |
| Combined equity | 1,608 | 34,047 |
| Total liabilities and combined equity | $ 106,786 | $ 95,622 |

| | For Year Ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| **INCOME STATEMENT DATA:** | | | |
| Revenues | $ 347,561 | $ 257,539 | $ 230,429 |
| Operating income | 12,908 | 8,552 | 9,275 |
| Net income | 4,721 | 4,657 | 5,037 |

### Offshore Pipelines & Services

At December 31, 2005, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

*Poseidon*. We own a 36% interest in Poseidon, which owns a crude oil pipeline that gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana.

*Cameron Highway*. We own a 50% interest in Cameron Highway, which owns a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. The Cameron Highway Oil Pipeline commenced operations during the first quarter of 2005.

*Deepwater Gateway*. We own a 50% interest in Deepwater Gateway, which owns the Marco Polo platform located in Green Canyon Block 608 of the Gulf of Mexico. The Marco Polo platform processes crude oil and natural gas production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico.

*Neptune*. We own a 25.7% interest in Neptune, which owns the Manta Ray Offshore Gathering System and Nautilus System, which are natural gas pipelines located in the Gulf of Mexico.

*Nemo*. We own a 33.9% interest in Nemo, which owns the Nemo Gathering System, which is a natural gas pipeline located in the Gulf of Mexico.

In connection with obtaining regulatory approval for the GulfTerra Merger, we were required by the U.S. Federal Trade Commission ("FTC") to sell our ownership interest in Starfish by March 31, 2005. We classified the $36.6 million carrying value of this investment under "Assets held for sale" on our Consolidated Balance Sheet at December 31, 2004. In March 2005, we sold this asset to a third party for $42.1 million in cash and realized a gain on the sale of $5.5 million.

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

| | At December 31, 2005 | At December 31, 2004 |
|---|---|---|
| **BALANCE SHEET DATA:** | | |
| Current assets | $ 141,756 | $ 79,196 |
| Property, plant and equipment, net | 1,201,926 | 712,182 |
| Other assets | 7,961 | 528,443 |
| Total assets | $ 1,351,643 | $ 1,319,821 |
| | | |
| Current liabilities | $ 120,611 | $ 71,758 |
| Other liabilities | 511,633 | 526,990 |
| Combined equity | 719,399 | 721,073 |
| Total liabilities and combined equity | $ 1,351,643 | $ 1,319,821 |

| | For Year Ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| **INCOME STATEMENT DATA:** | | | |
| Revenues | $ 1,309,836 | $ 88,603 | $ 76,168 |
| Operating income | 78,027 | 46,938 | 39,658 |
| Net income | 29,161 | 38,473 | 33,700 |

## Petrochemical Services

At December 31, 2005, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

*BRPC*. We own a 30% interest in BRPC, which owns a propylene fractionation facility located in south Louisiana.

*La Porte*. We own an aggregate 50% interest in La Porte, which owns a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

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

| | At December 31, 2005 | At December 31, 2004 |
|---|---|---|
| **BALANCE SHEET DATA:** | | |
| Current assets | $ 5,508 | $ 3,266 |
| Property, plant and equipment, net | 54,751 | 57,516 |
| Total assets | $ 60,259 | $ 60,782 |
| | | |
| Current liabilities | $ 1,178 | $ 438 |
| Other liabilities | 1 | |
| Combined equity | 59,080 | 60,344 |
| Total liabilities and combined equity | $ 60,259 | $ 60,782 |

| | For Year Ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| **INCOME STATEMENT DATA:** | | | |
| Revenues | $ 16,849 | $ 18,378 | $ 14,512 |
| Operating income | 2,606 | 5,131 | 2,726 |
| Net income | 2,650 | 5,151 | 2,685 |

Equity earnings from unconsolidated affiliates for 2003 includes a $22.5 million loss related to non-cash impairment charges recorded by BEF, a former unconsolidated affiliate that we now wholly own and consolidate. 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 for domestic MTBE sales 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 BEF recognizing a non-cash asset impairment charge of $67.5 million. Based on our ownership interest at the time, we recorded our 33.3% share of this loss ($22.5 million) in equity earnings from BEF.

### Other, Non-Segment

The Other, Non-Segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with the GulfTerra Merger. Our $425 million 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.

## 12. Business Combinations and Other Acquisitions

### 2003 Transactions

Our expenditures for business combinations and acquisitions during 2003 were $37.3 million, which included $4.9 million of purchase price adjustments relating to transactions that occurred prior to 2003.

In March 2003, we purchased an additional 50% ownership interest in EPIK, which owns our NGL export terminal located on the Houston Ship Channel. Also in March 2003, we acquired entities that own the Port Neches petrochemical pipeline. In September 2003, we acquired an additional ownership interest in BEF, which owns our octane additive production facility. In October 2003, we purchased an additional 37.4% ownership interest in Wilprise, which owns an NGL pipeline in Louisiana. In November 2003, we purchased an additional 50% ownership interest in OTC. As a result of these transactions, all of these entities became consolidated subsidiaries of ours.

Our purchase of a 50% equity interest in GulfTerra GP in December 2003 from El Paso was accounted for as an investment in an unconsolidated affiliate (see Note 11). Upon completion of the GulfTerra Merger, GulfTerra GP became a consolidated subsidiary of ours.

### 2004 Transactions

Our expenditures for business combinations and acquisitions during 2004 were $4.1 billion, which includes consideration paid or granted to complete the GulfTerra Merger in September 2004.

*GulfTerra Merger*. In September 2004, we completed the merger of GulfTerra with a wholly-owned subsidiary of ours. In addition, we completed certain other transactions related to the merger, including (i) the receipt of Enterprise Products GP's contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise Products GP from El Paso; and (ii) the purchase of certain midstream energy assets located in South Texas from El Paso. As a result of the merger transactions, GulfTerra and GulfTerra GP became wholly-owned subsidiaries of ours.

The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion.  The merger occurred in several interrelated transactions as described below.

- *Step One*. In December 2003, we purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owned a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, we accounted for our investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One was borrowed under an interim term loan and our pre-merger revolving credit facilities. This borrowing was fully repaid using net proceeds from equity offerings completed during 2004.

- *Step Two*. On September 30, 2004, the GulfTerra Merger was completed and GulfTerra and GulfTerra GP became wholly-owned subsidiaries of ours.  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 Products GP acquired from El Paso the remaining 50% membership interest in GulfTerra GP for $370 million in cash and the issuance of a 9.9% membership interest in Enterprise Products GP to El Paso. Subsequently, Enterprise Products 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 Products GP borrowed the $370 million from an affiliate of EPCO, which obtained the required funds through a loan from EPCO (which at the time indirectly owned the remaining membership interests in Enterprise Products GP).

    - Immediately prior to closing the GulfTerra Merger, we 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 were converted into 104,549,823 of our common units, of which 13,454,498 were issued to El Paso.

- *Step Three*. Immediately after Step Two was completed, we acquired certain midstream assets located in South Texas from El Paso for $155.3 million in cash.

In connection with closing the merger transactions, our Operating Partnership borrowed an aggregate $2.8 billion under its credit facilities to fund our cash payment obligations under Steps Two and Three of the GulfTerra Merger and to finance tender offers for GulfTerra's outstanding senior and senior subordinated notes.

The total consideration paid or granted for the GulfTerra Merger (including $7 million of purchase price adjustments paid during 2005) is summarized below:

| | |
|---|---|
| **Step One transaction:** | |
| Cash payment by us 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 us 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 our common units issued in exchange for remaining GulfTerra common units (see Note 15) | 2,445,420 |
| Fair value of our additional equity interests granted for unit awards and Series F2 convertible units | 3,675 |
| Fair value of receivable from El Paso for transition support payments (2) | (40,313) |
| Transaction fees and other direct costs incurred by us as a result of the GulfTerra Merger (3) | 31,011 |
| Total Step Two consideration | 3,401,140 |
| Total Step One and Step Two consideration | 3,826,140 |
| **Step Three transaction:** | |
| Purchase of South Texas midstream assets from El Paso | 155,277 |
| Total consideration for Steps One through Three | $ 3,981,417 |

(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 Products 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 Products GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise Products 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 us to purchase our initial 50% non-voting membership interest in GulfTerra GP in December 2003. The contribution of this 50% membership interest to us is allocated for financial reporting purposes to our 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 us 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 us 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 was discounted to fair value and recorded as a reduction in the purchase consideration for GulfTerra. As December 31, 2005, the fair value of the current portion and non-current portion of this contract-based receivable was $11.3 million and $8.3 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, 2005.

(3) As a result of the GulfTerra Merger, we incurred expenses of approximately $31 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 us 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 were required under a consent decree to sell our 50% interest in Starfish, which owns the Stingray natural gas pipeline, and an undivided 50% interest in a Mississippi propane storage facility. We completed the sale of the storage facility in December 2004 and the sale of our investment in Starfish in March 2005.

In addition to the GulfTerra Merger, our business combinations and acquisitions during 2004 included the purchase of (i) an additional 16.7% ownership interest in Tri-States; (ii) an additional 10% ownership interest in Seminole; (iii) the remaining 33.3% ownership interest in BEF; and (iv) certain assets located in Morgan's Point, Texas.

As a result of the final purchase price allocation for the GulfTerra Merger, we recorded $743.4 million of amortizable intangible assets and $387.1 million of goodwill. For additional information regarding these intangible assets, please read Note 13.

### 2005 Transactions

Our expenditures for business combinations and acquisitions during 2005 were $326.6 million, which included $8.3 million of purchase price adjustments relating to transactions that occurred prior to 2005.

In January 2005, we acquired indirect ownership interests in the Indian Springs Gathering System and Indian Springs natural gas processing plant for $74.9 million. In January and February 2005, we acquired an additional 46% of the ownership interests in Dixie for $68.6 million. In June 2005, we acquired additional indirect ownership interests in our Mid-America Pipeline System and Seminole Pipeline for $25 million. Also in June 2005, we acquired an additional 41.7% ownership interest in Belle Rose, which owns an NGL pipeline located in Louisiana, for $4.4 million. In July 2005, we purchased three underground NGL storage facilities and four propane terminals from Ferrellgas L.P. ("Ferrellgas") for $145.5 million in cash. Dixie and Belle Rose became consolidated subsidiaries of ours in 2005 as a result of our acquisition of additional ownership interests in these two entities.

During 2005, we paid El Paso an additional $7 million in purchase price adjustments related to the GulfTerra Merger, the majority of which were related to merger-related financial advisory services and involuntary severance costs. In addition, we made various minor revisions to the GulfTerra Merger purchase price allocation before it was finalized on September 30, 2005.

## Purchase Price Allocation for 2005 Transactions

Our 2005 acquisitions and post-closing purchase price adjustments were accounted for using the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated preliminary fair values as follows:

| | Indian Springs | Dixie | Ferrellgas Assets | Other (2) | Total |
|---|---|---|---|---|---|
| **Purchase price allocation:** | | | | | |
| **Assets acquired in business combination:** | | | | | |
| Current assets | $ 252 | $ (476) | $ 6,901 | $ 2,217 | $ 8,894 |
| Property, plant and equipment, net | 40,321 | 90,306 | 144,092 | 30,358 | 305,077 |
| Investments in and advances to unconsolidated affiliates (1) | | (36,279) | | (10,017) | (46,296) |
| Intangible assets | 19,095 | | 109 | 1,009 | 20,213 |
| Other assets | | 31,185 | | (3,694) | 27,491 |
| Total assets acquired | 59,668 | 84,736 | 151,102 | 19,873 | 315,379 |
| **Liabilities assumed in business combination:** | | | | | |
| Current liabilities | (118) | (2,758) | (5,580) | (4,761) | (13,217) |
| Long-term debt | | (9,982) | | | (9,982) |
| Other long-term liabilities | (61) | (7,697) | | | (7,758) |
| Minority interest | | (4,586) | | 11,603 | 7,017 |
| Total liabilities assumed | (179) | (25,023) | (5,580) | 6,842 | (23,940) |
| Total assets acquired less liabilities assumed | 59,489 | 59,713 | 145,522 | 26,715 | 291,439 |
| Total consideration given | 74,854 | 68,608 | 145,522 | 37,618 | 326,602 |
| **Goodwill** | $ 15,365 | $ 8,895 | $ - | $ 10,903 | $ 35,163 |

(1) Represents carrying value of our investment prior to consolidation.
(2) Includes purchase accounting adjustments for the GulfTerra Merger and preliminary purchase price allocations for the Mid-America, Seminole, Belle Rose and petrochemical pipeline transactions.

The purchase price allocations for our 2005 transactions are preliminary. We engaged an independent third party business valuation expert to assess the fair value of tangible and intangible assets acquired in connection with the Indian Springs, Dixie, Belle Rose and Ferrellgas transactions. This information will assist us in developing final purchase price allocations for these transactions. Management developed its own fair value estimates of assets acquired and liabilities assumed in connection with the remaining 2005 transactions. Our preliminary values are subject to final valuation reports and additional information.

### Selected Pro Forma Financial Information (Unaudited)

Our historical operating results were affected by business combinations and asset acquisitions during 2005 and 2004. Our most significant recent transaction was the GulfTerra Merger. Since the closing date of the GulfTerra Merger was 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 (Step Three of the GulfTerra Merger) was September 1, 2004. As a result, our Statements of Consolidated Operations and Comprehensive Income for 2004 include four months of earnings from the South Texas midstream assets. Our 2005 results already reflect the businesses we acquired in connection with the GulfTerra Merger; therefore, no pro forma adjustments are necessary for the 2005 period. Due to the immaterial nature of our other business combinations and acquisitions since 2004, our selected pro forma financial information includes only adjustments related to the GulfTerra Merger. Our pro forma basic and diluted earnings per unit amounts for 2005 are practically the same as our actual basic and diluted earnings per unit for 2005.

The pro forma information presented in the following table is based on financial data available to us and includes certain estimates and assumptions made by our management. Our pro forma earnings data has been prepared as if the GulfTerra Merger transaction had been completed on January 1, 2004, as opposed to September 30, 2004. As a result, our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the GulfTerra Merger transactions actually occurred on this earlier date.

| | For Year Ended December 31, 2004 |
|---|---|
| Pro forma earnings data: | |
| Revenues | $ 9,615.1 |
| Costs and expenses | $ 9,067.2 |
| Operating income | $ 576.3 |
| Net income | $ 335.4 |
| | |
| Pro forma net income | $ 335.4 |
| Less incentive earnings allocations to Enterprise Products GP | (46.1) |
| Pro forma net income after incentive earnings allocation | 289.3 |
| Multiplied by Enterprise Products GP ownership interest | 2.0% |
| Standard earnings allocation to Enterprise Products GP | $ 5.8 |
| | |
| Incentive earnings allocation to Enterprise Products GP | $ 46.1 |
| Standard earnings allocation to Enterprise Products GP | 5.8 |
| General partner interest in pro forma net income | $ 51.9 |
| | |
| Pro forma net income | $ 335.4 |
| Less general partner interest in pro forma net income | (51.9) |
| Pro forma net income available to limited partners | $ 283.5 |
| | |
| Basic earnings per unit, net of general partner interest: | |
| As reported basic units outstanding | 265.4 |
| Pro forma basic units outstanding | 378.8 |
| As reported basic net income per unit | $ 0.87 |
| Pro forma basic net income per unit | $ 0.75 |
| Diluted earnings per unit, net of general partner interest: | |
| As reported diluted units outstanding | 266.0 |
| Pro forma diluted units outstanding | 379.4 |
| As reported diluted net income per unit | $ 0.87 |
| Pro forma diluted net income per unit | $ 0.75 |

## 13. Intangible Assets and Goodwill

### Identifiable Intangible Assets

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

| | | At December 31, 2005 | | At December 31, 2004 | |
|---|---|---|---|---|---|
| | Gross Value | Accum. Amort. | Carrying Value | Accum. Amort. | Carrying Value |
| **NGL Pipelines & Services:** | | | | | |
| Shell processing agreement | $ 206,216 | $ (56,157) | $ 150,059 | $ (45,110) | $ 161,106 |
| STMA and GulfTerra NGL business customer relationships (1) | 49,784 | (7,829) | 41,955 | (1,606) | 48,004 |
| Markham NGL storage contracts (1) | 32,664 | (5,444) | 27,220 | (1,088) | 31,576 |
| Toca-Western contracts | 31,229 | (5,595) | 25,634 | (4,033) | 27,196 |
| Indian Springs customer relationships | 16,439 | (1,954) | 14,485 | | |
| Mont Belvieu storage contracts | 8,127 | (929) | 7,198 | (697) | 7,430 |
| Other | 10,804 | (1,577) | 9,227 | (601) | 7,651 |
| Segment total | 355,263 | (79,485) | 275,778 | (53,135) | 282,963 |
| **Onshore Natural Gas Pipelines & Services:** | | | | | |
| San Juan Gathering System customer relationships (1) | 331,311 | (30,065) | 301,246 | (6,222) | 325,089 |
| Petal & Hattiesburg natural gas storage contracts (1) | 100,499 | (10,742) | 89,757 | (2,059) | 98,440 |
| Texas Intrastate pipeline customer relationships (1) | 20,992 | (2,538) | 18,454 | (531) | 20,461 |
| Other | 4,996 | (610) | 4,386 | (63) | 2,277 |
| Segment total | 457,798 | (43,955) | 413,843 | (8,875) | 446,267 |
| **Offshore Pipelines & Services:** | | | | | |
| Offshore pipeline & platform customer relationships (1) | 205,845 | (32,480) | 173,365 | (6,965) | 198,880 |
| Other | 1,167 | | 1,167 | | 1,167 |
| Segment total | 207,012 | (32,480) | 174,532 | (6,965) | 200,047 |
| **Petrochemical Services:** | | | | | |
| Mont Belvieu propylene fractionation contracts | 53,000 | (5,931) | 47,069 | (4,417) | 48,583 |
| Other | 3,674 | (1,270) | 2,404 | (791) | 2,741 |
| Segment total | 56,674 | (7,201) | 49,473 | (5,208) | 51,324 |
| Total all segments | $ 1,076,747 | $ (163,121) | $ 913,626 | $ (74,183) | $ 980,601 |

(1) Acquired in connection with the GulfTerra Merger in September 2004

The following table shows the amortization of our intangible assets by segment for the periods indicated:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| NGL Pipelines & Services | $ 26,350 | $ 16,000 | $ 12,977 |
| Onshore Natural Gas Pipelines & Services | 35,080 | 8,875 | |
| Offshore Pipelines & Services | 25,515 | 6,965 | |
| Petrochemical Services | 1,993 | 1,973 | 1,848 |
| Total all segments | $ 88,938 | $ 33,813 | $ 14,825 |

Based on information currently available, we estimate that amortization expense associated with existing intangible assets will approximate \$82.5 million in 2006, \$77.2 million in 2007, \$72.4 million in 2008, \$67.5 million in 2009 and \$63.7 million in 2010.

Our significant intangible assets can be classified into the following categories: (i) the Shell Processing Agreement; (ii) the intangible assets we acquired in connection with the GulfTerra Merger; and (iii) other customer relationships and contracts. The following is a description of these significant categories:

*Shell Processing Agreement*. The Shell Processing Agreement grants us the right to process Shell's (or its assignee's) current and future production within the state and federal waters of the Gulf of Mexico. We acquired this intangible asset in connection with our 1999 acquisition of certain of Shell's midstream energy assets located along the Gulf Coast. The value of the Shell Processing Agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019.

*Intangible assets acquired in connection with GulfTerra Merger*. We acquired customer relationship and contract-based intangible assets in connection with the GulfTerra Merger. The customer relationship intangible assets represent the exploration and production, natural gas processing and NGL fractionation customer bases served by the GulfTerra and South Texas midstream assets at the time the merger was completed. The contract-based intangible assets represent the rights we acquired in connection with discrete contracts that GulfTerra had entered into to provide storage services for natural gas and NGLs.

The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful 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. This group of intangible assets primarily consists of the (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Texas Intrastate pipeline customer relationships; and (iv) STMA and GulfTerra NGL Business customer relationships.

The contract-based intangible assets are being amortized over the estimated useful life (or term) of each agreement, which we estimate to range from two to eighteen years. This group of intangible assets consists of the (i) Petal and Hattiesburg natural gas storage contracts and (ii) Markham NGL storage contracts.

*Other significant customer relationship and contract-based intangible assets*. In January 2005, we acquired customer relationship intangible assets in connection with our purchase of indirect ownership interests in the Indian Springs natural gas gathering pipelines and processing assets. We are amortizing these intangible assets over a 19-year period, which is the expected life of the customers' underlying resource bases.

In 2002, we acquired contract-based intangible assets in connection with the purchase of (i) a propylene fractionation facility and underground NGL and petrochemical storage caverns located in Mont Belvieu, Texas and (ii) a natural gas processing and NGL fractionation facility located in Louisiana (the "Toca-Western" contracts). In general, the values assigned to these intangible assets are being amortized on a straight-line basis over the estimated remaining economic life of underlying assets to which they relate, which ranged from 20 to 35 years at inception.

## Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing. The following table summarizes our goodwill amounts by segment at the dates indicated:

| | At December 31, 2005 | At December 31, 2004 |
|---|---|---|
| **NGL Pipelines & Services** | | |
| GulfTerra Merger | $ 23,927 | $ 24,026 |
| Acquisition of Indian Springs natural gas processing assets | 13,180 | |
| Other | 17,853 | 8,737 |
| **Onshore Natural Gas Pipelines & Services** | | |
| GulfTerra Merger | 280,812 | 290,397 |
| Acquisition of Indian Springs natural gas gathering assets | 2,185 | |
| **Offshore Pipelines & Services** | | |
| GulfTerra Merger | 82,386 | 62,348 |
| **Petrochemical Services** | | |
| Acquisition of Mont Belvieu propylene fractionation assets | 73,690 | 73,690 |
| Totals | $ 494,033 | $ 459,198 |

The goodwill resulting from the GulfTerra Merger can be attributed to our belief (at the time the merger was consummated) that the combined partnerships would benefit from the strategic location of each partnership's assets and the industry relationships that each possessed. In addition, we expected that various operating synergies would develop (such as reduced general and administrative costs and interest savings) that could improve financial results of the merged entities. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies serving producers in 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.

The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our purchase of propylene fractionation assets in February 2002. We also recorded goodwill in connection with our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing assets in January 2005.

## 14. Debt Obligations

Our consolidated debt consisted of the following at the dates indicated:

| | December 31, 2005 | December 31, 2004 |
|---|---|---|
| Operating Partnership debt obligations: | | |
| 364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (1) | | $ 242,229 |
| Multi-Year Revolving Credit Facility, variable rate, due October 2010 | $ 490,000 | 321,000 |
| Seminole Notes, 6.67% fixed rate, repaid December 2005 | | 15,000 |
| 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 |
| 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 | 500,000 |
| Senior Notes F, 4.625% fixed rate, due October 2009 | 500,000 | 500,000 |
| Senior Notes G, 5.60% fixed rate, due October 2014 | 650,000 | 650,000 |
| Senior Notes H, 6.65% fixed rate, due October 2034 | 350,000 | 350,000 |
| Senior Notes I, 5.00% fixed rate, due March 2015 (2) | 250,000 | |
| Senior Notes J, 5.75% fixed rate, due March 2035 (3) | 250,000 | |
| Senior Notes K, 4.950% fixed rate, due June 2010 (4) | 500,000 | |
| Dixie Revolving Credit Facility, variable rate, due June 2007 | 17,000 | |
| Debt obligations assumed from GulfTerra | 5,068 | 6,469 |
| Total principal amount | 4,866,068 | 4,288,698 |
| Other, including unamortized discounts and premiums and changes in fair value (5) | (32,287) | (7,462) |
| Subtotal long-term debt | 4,833,781 | 4,281,236 |
| Less current maturities of debt (6) | | (15,000) |
| Long-term debt | $ 4,833,781 | $ 4,266,236 |
| Standby letters of credit outstanding | $ 33,129 | $ 139,052 |

(1) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility. For additional information regarding this equity offering, see Note 15.

(2) Senior Notes I were issued at 99.379% of their face amount in February 2005.

(3) Senior Notes J were issued at 98.691% of their face amount in February 2005.

(4) Senior Notes K were issued at 99.834% of their face amount in June 2005.

(5) The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts. The December 31, 2004 amount includes $1.8 million related to fair value hedges and $9.2 million in net unamortized discounts.

(6) 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 Facility using proceeds from an equity offering completed in February 2005.

### Letters of Credit

At December 31, 2005, we had $33.1 million in standby letters of credit outstanding which were issued under our Multi-Year Revolving Credit Facility. At December 31, 2004, we had $139.1 million of standby letters of credit outstanding, of which $115.1 million were issued under a letter of credit facility associated with our Independence Trail capital project. The decrease in letters of credit outstanding since 2004 is primarily due to the expiration of the Independence Trail letter of credit facility in October 2005.

### Parent-Subsidiary Guarantor Relationships

At December 31, 2005, we act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Dixie revolving credit facility and the 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.

Our Operating Partnership's senior indebtedness is structurally subordinated to and ranks junior in right of payment to the indebtedness of GulfTerra and Dixie. This subordination feature exists only to the extent that the repayment of debt incurred by GulfTerra and Dixie is dependent upon the assets and operations of these two entities. The Dixie revolving credit facility is an unsecured obligation of Dixie (of which we own 65.9% of its capital stock). The senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

### Operating Partnership Debt Obligations

*364-Day Acquisition Credit Facility.* In August 2004, our Operating Partnership entered into a $2.25 billion 364-Day Acquisition Credit Facility, which was used to provide interim financing for certain purchase transactions associated with the GulfTerra Merger and the refinancing of substantially all of GulfTerra's then outstanding debt. We repaid approximately $2 billion of this indebtedness in October 2004 using proceeds from our issuance of Senior Notes E, F, G and H. In February 2005, we repaid the remaining balance using proceeds from our February 2005 common unit offering and terminated the facility.

*Multi-Year Revolving Credit Facility*. In August 2004, our Operating Partnership entered into a five-year multi-year revolving credit agreement in connection with the completion of the GulfTerra Merger. In October 2005, the borrowing capacity under this credit agreement was increased from $750 million to $1.25 billion, with the possibility that the borrowing capacity could be further increased to $1.4 billion (subject to certain conditions). In addition, the maturity date for debt outstanding under the facility was extended from September 2009 to October 2010. The Operating Partnership may make up to two requests for one-year extensions of the maturity date (subject to certain conditions). There is no limit on the amount of standby letters of credit that can be outstanding under the amended facility.

The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise Products 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 (i) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½%; (ii) a Eurodollar rate plus an applicable margin; or (iii) a Competitive Bid Rate.

This revolving credit agreement contains 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 requires us to satisfy certain financial covenants at the end of each fiscal quarter. The Multi-Year Revolving Credit Facility restricts the Operating Partnership's ability to pay cash distributions to us if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

*Seminole Notes*. Seminole Pipeline Company ("Seminole"), a majority-owned subsidiary, made the final $15 million payment on its indebtedness in December 2005.

*Pascagoula MBFC Loan*. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, the 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.

The indenture agreement for this loan contains an acceleration clause whereby if the Operating Partnership's credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's remaining at BB+ or lower, 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.

*Senior Notes A through K*. These fixed rate notes are unsecured obligations 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 Products GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Our guarantee of such notes is non-recourse to Enterprise Products GP.

Senior Notes A through D 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. The remainder of the Senior Notes (E through K) are also subject to similar covenants.

Senior Notes E, F, G and H were issued as private placement debt in September 2004 and generated an aggregate $2 billion in proceeds, which were used to repay amounts borrowed under the 364-Day Acquisition Credit Facility. Senior Notes E through H were exchanged for registered debt securities in March 2005.

Senior Notes I and J were issued as private placement debt in February 2005 and generated an aggregate $500 million in proceeds, which were used to repay $350 million due under Senior Notes A (which matured in March 2005) and the remainder for general partnership purposes, including the temporary repayment of amounts then outstanding under the Multi-Year Revolving Credit Facility. Senior Notes I and J were exchanged for registered debt securities in August 2005.

Senior Notes K were issued as registered securities in June 2005 and generated $500 million in proceeds, which were used for general partnership purposes, including the temporary repayment of amounts then outstanding under the Multi-Year Revolving Credit Facility. Senior Notes K were issued under the $4 billion universal shelf registration statement we filed in March 2005 (see Note 15).

### Dixie Revolving Credit Facility

As a result of acquiring a controlling interest in Dixie in February 2005, we began consolidating the financial statements of Dixie with those of our own. Dixie's debt obligations consist of a senior unsecured revolving credit facility having a borrowing capacity of $28 million.

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 either (i) a Eurodollar rate plus an applicable margin or (ii) the greater of (a) the Prime Rate or (b) the Federal Funds Rate by ½%.

This revolving credit agreement contains various covenants related to Dixie's ability to incur certain indebtedness, grant certain liens, enter into merger transactions and make certain investments. The loan agreement also requires Dixie to satisfy a minimum net worth financial covenant. The revolving credit agreement restricts Dixie's ability to pay cash dividends to us and its other stockholders if a default or an event of default (as defined in the credit agreement) has occurred and its continuing at the time such dividend is scheduled to be paid.

### Debt Obligations Assumed from GulfTerra

*Senior and Senior Subordinated Notes*. Upon completion of the GulfTerra Merger, we recorded in consolidation $921.5 million of GulfTerra's then outstanding senior and senior subordinated notes. Of this amount, $915 million was purchased by our Operating Partnership in October 2004 pursuant to its tender offers for such debt. The Operating Partnership financed these purchases using borrowings under its 364-Day Acquisition Credit Facility. The noteholders also approved (as a condition to accepting the tender offers) amendments that removed all restrictive covenants governing the GulfTerra notes.

At December 31, 2004, $6.5 million in principal amount of these obligations remained outstanding. During 2005, we redeemed an additional $1.4 million of this assumed debt. The $5.1 million in principal remaining outstanding at December 31, 2005 bears fixed rate interest of 8.5% and matures in June 2010.

*Petal Industrial Development Revenue Bonds*. In April 2004, Petal Gas Storage L.L.C. ("Petal"), one of our wholly-owned subsidiaries, borrowed $52 million from the MBFC. Concurrently, the MBFC sold $52 million in Industrial Development Bonds to another of our wholly-owned subsidiaries. Petal had the option to repay its MBFC loan without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. In August 2005, Petal exercised its option to repay the loan agreement and the $52 million in Industrial Development Bonds were redeemed and retired.

Prior to redemption, we netted the Petal MBFC loan payable against the Industrial Development Bonds receivable and also the related interest payable and receivable amounts on our balance sheet. Additionally, we netted the interest expense and interest income amounts attributable to these instruments on our statements of consolidated operations. This presentation was in accordance with the provisions of FIN 39, "*Offsetting of Amounts Related to Certain Contracts*," and SFAS 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*," since we had the ability and intent to offset these items.

### Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2005 and 2004.

### Information Regarding Variable Interest Rates Paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our significant consolidated variable rate debt obligations during 2005.

| | Range of Interest Rates Paid | Weighted-Average Interest Rate Paid |
|---|---|---|
| 364-Day Acquisition Credit Facility | 3.25% to 3.40% | 3.35% |
| Multi-Year Revolving Credit Facility | 3.22% to 7.00% | 4.25% |
| Dixie Revolving Credit Facility | 3.66% to 4.67% | 4.12% |

### Consolidated Debt Maturity Table

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

| | |
|---|---|
| 2006 | None |
| 2007 | $ 517,000 |
| 2008 | None |
| 2009 | 500,000 |
| 2010 | 1,049,068 |
| Thereafter | 2,800,000 |
| Total scheduled principal payments | $ 4,866,068 |

### Joint Venture Debt Obligations

We have three unconsolidated affiliates with long term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2005; (ii) total debt of each unconsolidated affiliate at December 31, 2005 on a 100% basis to the joint venture; and (iii) the corresponding scheduled maturities of such debt.

| | Our Ownership Interest | Total | Scheduled Maturities of Debt 2006 | 2007 | 2008 | 2009 | 2010 | After 2010 |
|---|---|---|---|---|---|---|---|---|
| Cameron Highway | 50.0% | $ 415,000 | | | $ 25,000 | $ 25,000 | $ 50,000 | $ 315,000 |
| Poseidon | 36.0% | 95,000 | | | 95,000 | | | |
| Evangeline | 49.5% | 30,650 | $ 5,000 | $ 5,000 | 5,000 | 5,000 | 10,650 | |
| Total | | $ 540,650 | $ 5,000 | $ 5,000 | $ 125,000 | $ 30,000 | $ 60,650 | $ 315,000 |

The credit agreements of our joint ventures contain various affirmative and negative covenants, including financial covenants. Our joint ventures were in compliance with all such covenants at December 31, 2005. The credit agreements of our joint ventures restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid.

In March 2005, we contributed $72 million to Deepwater Gateway to assist in the repayment of its $144 million term loan. Our joint venture partner in Deepwater Gateway also contributed $72 million. Deepwater Gateway used funds borrowed under its term loan to fund a substantial portion of the cost to construct the Marco Polo platform and related facilities.

The following information summarizes significant terms of the debt obligations of our unconsolidated affiliates at December 31, 2005:

*Cameron Highway*. In July 2003, Cameron Highway entered into a $325 million project loan facility to finance a substantial portion of the cost to construct its crude oil pipeline. In June 2005, Cameron Highway executed a new term loan agreement with a total credit commitment of $415 million and borrowed the full amount, which was used to repay principal amounts outstanding under the project loan facility and to make $95 million in cash distributions to its partners. We received a partial return of our investment in Cameron Highway of $47.5 million in connection with this special distribution. In connection with this refinancing, Cameron Highway incurred $22 million in one-time cash make-whole premiums and related fees and non-cash charges.

In December 2005, Cameron Highway issued $415 million of private placement, non-recourse senior secured notes due December 2017. Proceeds from the issuance of these senior secured notes were used to repay the $415 million term loan that Cameron Highway entered into during June 2005. The senior secured notes were issued in two series - $365 million of Series A notes, which have a fixed rate interest of 5.86%, and $50 million of Series B notes, which have a variable rate interest based on a Eurodollar rate plus 1%. At December 31, 2005, the variable interest rate charged under the Series B notes was 4.52%.

The notes are secured by (i) mortgages on and pledges of substantially all of the assets of Cameron Highway; (ii) mortgages on and pledges of certain assets related to certain rights of way and pipeline assets of an indirect wholly-owned subsidiary of ours that serves as the operator of the Cameron Highway Oil Pipeline; (iii) pledges by us and our joint venture partner in Cameron Highway of our 50% partnership interests in Cameron Highway; and (iv) letters of credit in an initial amount of $18.4 million each issued by our Operating Partnership and an affiliate of our joint venture partner. Except for the foregoing, the noteholders do not have any recourse against our assets or any of our subsidiaries under the note purchase agreement.

*Poseidon*. Poseidon has entered into a $170 million revolving credit facility that matures in January 2008. The interest rates charged under this revolving credit facility are variable and depend on the ratio of Poseidon's total debt to its earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon's assets. The variable interest rates charged on this debt at December 31, 2005 and 2004 were 5.34% and 4.58%, respectively.

*Evangeline*. At December 31, 2005, long-term debt for Evangeline consisted of (i) $23.2 million in principal amount of 9.9% fixed rate Series B senior secured notes due 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 reserve 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 as a result of its acquisition of a contract-based intangible asset in the 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. Variable rate interest accrues on the subordinated note at a Eurodollar rate plus ½%. The variable interest rates charged on this note at December 31, 2005 and 2004 were 3.58% and 1.73%, respectively. Accrued interest payable related to the subordinated note was $7.1 million and $6.6 million at December 31, 2005 and 2004.

## 15. Partners' Equity

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 Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, Enterprise Products GP.

### Capital Accounts

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and 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.

Our Partnership Agreement sets forth the calculation used in determining the amount and priority of cash distributions that our limited partners and general partner 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 to our general partner. See Note 16 for information regarding our cash distributions to partners, including incentive cash distributions to Enterprise Products GP.

In August 2005, we revised our Partnership Agreement to allow Enterprise Products GP, at its discretion, to elect not to make its proportionate capital contributions to us in connection with our issuance of limited partner interests, in which case its 2% general partner would be proportionately reduced. Historically, Enterprise Products GP has contributed cash to us (at the time of these offerings) to maintain its 2% general partner interest in us. Enterprise Products GP made such cash contributions to us during 2005. If Enterprise Products GP exercises this option in the future, the amount of earnings we allocate to it and the cash distributions it receives from us will be reduced accordingly. If this occurs, Enterprise Products GP can, under certain conditions, restore its full 2% general partner interest by making additional cash contributions to us.

### Equity Offerings and Registration Statements

In general, the Partnership Agreement 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 may be established by Enterprise Products GP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders). We completed a number of common unit offerings in 2005, 2004 and 2003.

The following table reflects the number of common units issued and the net proceeds received from these offerings:

| | | Net Proceeds | | | |
|---|---|---|---|---|---|
| | Number of Common Units Issued | Contributed by Limited Partners | Contributed by General Partner | Contributed by General Partner in Minority Interest (1) | Total |
| **Fiscal 2003:** | | | | | |
| Underwritten Offerings (2) | 26,622,500 | $ 508,833 | $ 5,139 | $ 5,247 | $ 519,219 |
| Other Offerings (3) | 2,883,803 | 59,112 | 600 | 614 | 60,326 |
| Total 2003 | 29,506,303 | $ 567,945 | $ 5,739 | $ 5,861 | $ 579,545 |
| **Fiscal 2004:** | | | | | |
| Underwritten Offerings (4) | 34,500,000 | $ 680,390 | $ 13,886 | | $ 694,276 |
| Other Offerings (3) | 5,183,591 | 109,368 | 2,231 | | 111,599 |
| Total 2004 | 39,683,591 | $ 789,758 | $ 16,117 | | $ 805,875 |
| **Fiscal 2005:** | | | | | |
| Underwritten Offerings: | | | | | |
| February 2005 (5) | 17,250,000 | $ 447,602 | $ 9,135 | | $ 456,737 |
| December 2005 (6) | 4,000,000 | 96,745 | 1,974 | | 98,719 |
| Other Offerings: (3) | | | | | |
| February 2005 | 1,516,561 | 38,249 | 780 | | 39,029 |
| May 2005 | 410,249 | 10,204 | 208 | | 10,412 |
| August 2005 | 399,812 | 9,934 | 204 | | 10,138 |
| November 2005 | 403,118 | 9,882 | 201 | | 10,083 |
| Total 2005 | 23,979,740 | $ 612,616 | $ 12,502 | | $ 625,118 |

(1) Prior to the restructuring of Enterprise Products GP's ownership interest in December 2003, Enterprise Products 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 the proceeds from these public offerings to repay a portion of the indebtedness under the Operating Partnership's 364-Day Term Loan we entered into to fund the Mid-America and Seminole acquisitions in July 2002 to reduce indebtedness outstanding under the Operating Partnership's revolving credit facilities and for general partnership purposes.

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

(4) We used the proceeds from these public offerings to (i) repay the Operating Partnership's $225 million Interim Term Loan related to the GulfTerra Merger; (ii) temporarily reduce borrowings outstanding under its revolving credit facilities; and (iii) partially fund our payment obligations to El Paso under Step Two of the GulfTerra Merger.

(5) We used the proceeds from this offering to repay the remaining amounts due under the Operating Partnership's 364-Day Acquisition Credit Facility and to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility.

(6) We used the proceeds from this offering to temporarily reduce borrowings outstanding under the Operating Partnership's Multi-Year Revolving Credit Facility.

In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of equity and debt securities. After taking into account our issuance of securities under this universal registration statement during 2005, we can issue an additional $3.4 billion of securities under this registration statement as of December 31, 2005.

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 into the purchase of additional common units. We have a registration statement on file with the SEC covering the issuance of up to 15,000,000 common units in connection with the DRIP. A total of 10,539,148 common units have been issued under this registration statement through December 31, 2005.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. A total of 227,986 common units have been issued to employees under this plan through December 31, 2005.

## Common Units Issued in Connection with the GulfTerra Merger

Under Step Two of the GulfTerra Merger (see Note 12), we issued 1.81 of our common units for each GulfTerra common unit (including restricted common units) remaining after our purchase of 2,876,620 GulfTerra common units owned by El Paso. The number of units we issued in connection with this conversion was calculated as follows:

| | |
|---|---|
| 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: | |
| Purchase of GulfTerra Series C units from El Paso in connection with Step Two | (10,937,500) |
| 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 | 57,762,369 |
| Conversion ratio (1.81 of our common units for each GulfTerra common unit) | 1.81 |
| 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 our common units immediately prior to and after proposed GulfTerra Merger was announced on December 15, 2003 | $ 23.39 |
| Fair value of our common units issued in conversion of remaining GulfTerra common units | $ 2,445,420 |

In accordance with purchase accounting, the $2.4 billion value of our common units was based on the average closing price of our common units immediately prior to and after the proposed merger was announced on December 15, 2003.

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 presents the detail for this consideration:

| | |
|---|---|
| Fair value of common units issued in conversion of remaining GulfTerra common units | $ 2,445,420 |
| Fair value of equity interests issued to acquire the remaining 50% membership interest in GulfTerra GP (voting interest) (1) | 461,347 |
| Fair value of other equity interests issued for unit awards and Series F2 convertible units | 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 Products GP to El Paso in Step Two 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 Products GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise Products GP received. The fair value of $461.3 million assigned to this voting membership interest in GulfTerra GP compares favorably to the $425 million we paid El Paso in December 2003 to purchase our initial 50% non-voting membership interest in GulfTerra GP. The contribution of this 50% membership interest to Enterprise Products Partners is allocated for financial reporting purposes to our 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.

As a result of the GulfTerra Merger, we assumed GulfTerra's obligation associated with its 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive our common units based on the 1.81 exchange ratio. In 2004, all of the convertible units were exercised and we issued 1,950,317 common units and received net proceeds of $40 million.

### Class B Special Units

In December 2003, we sold 4,413,549 Class B special units to an affiliate of EPCO for $100 million. After receiving the approval of our unitholders, we converted the Class B special units into an equal number of common units in July 2004.

### Subordinated Units and Class A Special Units Issued to Shell

We issued subordinated units and Class A special units to Shell in connection with our acquisition of certain midstream energy assets in 1999. Both classes of units converted to common units over a period of time extending into 2003. The conversion of subordinated units in 2003 had no impact on our earnings per unit or cash distributions since subordinated units were included in both the basic and fully-diluted earnings per unit calculations and were distribution bearing. The conversion of Class A special units in 2003 had a dilutive impact on basic earnings per unit since they increased 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.

### Treasury Units

In 2000, we and a consolidated trust (the "1999 Trust") were authorized by Enterprise Products GP to repurchase up to 2,000,000 publicly-held common units under an announced buy-back program. The repurchases would be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. After deducting for repurchases under the program in prior periods, we and the 1999 Trust could repurchase up to 618,400 common units at December 31, 2005. Common units repurchased under the program 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, treasury units are not considered to be outstanding. We reissued 371,113 units and 30,887 units out of treasury in 2004 and 2003, respectively, in connection with the exercise of unit options by employees of EPCO. We retired 30,000 treasury units in 2003 and cancelled the remaining 427,200 treasury units in 2005.

## Summary of Limited Partner Transactions since 2002

The following table details the changes in limited partners' equity since December 31, 2002:

| | Common Units | Restricted Common Units | Subordinated Units | Class A Special Units | Class B Special Units | Total |
|---|---|---|---|---|---|---|
| **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 | (254,111) | | (30,482) | | | (284,593) |
| Unit option reimbursements to EPCO | (2,721) | | | | | (2,721) |
| 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) | | | |
| Net proceeds from sales of common units | 567,945 | | | | | 567,945 |
| Proceeds from issuance of Class B special units | | | | | 100,000 | 100,000 |
| Restructuring of Enterprise Products 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 | (390,928) | (218) | | | (3,288) | (394,434) |
| Unit option reimbursements to EPCO | (3,813) | | | | | (3,813) |
| Net 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 |
| Net income | 347,948 | 564 | | | | 348,512 |
| Operating leases paid by EPCO | 2,067 | 3 | | | | 2,070 |
| Cash distributions to partners | (629,629) | (931) | | | | (630,560) |
| Unit option reimbursements to EPCO | (9,199) | | | | | (9,199) |
| Net proceeds from sales of common units | 612,616 | | | | | 612,616 |
| Proceeds from exercise of units options | 21,374 | | | | | 21,374 |
| Issuance of restricted units | | 9,478 | | | | 9,478 |
| Vesting of restricted units | 143 | (143) | | | | |
| Forfeiture of restricted units | | (2,663) | | | | (2,663) |
| Amortization of Employee Partnership awards | 1,355 | 3 | | | | 1,358 |
| Cancellation of treasury units | (8,915) | | | | | (8,915) |
| **Balance, December 31, 2005** | $5,542,700 | $ 18,638 | $ - | $ - | $ - | $ 5,561,338 |

## Unit History

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

| | Limited Partners | | | | | |
|---|---|---|---|---|---|---|
| | Common Units | Restricted Common Units | Subordinated Units | Class A Special Units | Class B Special Units | Treasury Units |
| **Balance, December 31, 2002** | 141,694,766 | | 32,114,804 | 10,000,000 | | 859,200 |
| Common units issued in connection with 2003 offerings | 29,526,948 | | | | | |
| Conversion of subordinated units to common units in May 2003 | 10,704,936 | | (10,704,936) | | | |
| 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) | | | |
| 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 connection with 2004 offerings | 39,700,078 | | | | | |
| Conversion of Class B special units to common units in July 2004 | 4,413,549 | | | | (4,413,549) | |
| Common and restricted common units issued to GulfTerra unitholders on September 30, 2004 in connection with the GulfTerra Merger | 104,495,523 | 54,300 | | | | |
| Common units issued in connection with conversion of Series F2 units in October and November 2004 | 1,950,317 | | | | | |
| Other restricted common units issued in 2004 | | 434,225 | | | | |
| Treasury units reissued to satisfy unit options | 371,113 | | | | | (371,113) |
| **Balance, December 31, 2004** | 364,297,340 | 488,525 | - | - | - | 427,200 |
| Common units issued in connection with February 2005 offering | 17,250,000 | | | | | |
| Other common units issued in February 2005 | 1,516,561 | | | | | |
| Restricted common units issued in February 2005 | | 12,892 | | | | |
| Common units issued in March 2005 in connection with units options | 195,000 | | | | | |
| Vesting of restricted units in April 2005 | 6,484 | (6,484) | | | | |
| Cancellation of treasury units in April 2005 | | | | | | (427,200) |
| Common units issued in May 2005 | 410,249 | | | | | |
| Restricted common units issued in May 2005 | | 269 | | | | |
| Common units issued in May 2005 in connection with units options | 525,000 | | | | | |
| Common units issued in August 2005 | 399,812 | | | | | |
| Restricted common units issued in August 2005 | | 316,425 | | | | |
| Common units issued in August 2005 in connection with units options | 71,000 | | | | | |
| Restricted common units forfeited in August 2005 | | (60,427) | | | | |
| Restricted common units forfeited in October 2005 | | (2,000) | | | | |
| Common units issued in connection with November 2005 offering | 4,000,000 | | | | | |
| Common units issued in November 2005 | 403,118 | | | | | |
| Restricted common units issued in November 2005 | | 32,425 | | | | |
| Common units issued in November 2005 in connection with units options | 35,000 | | | | | |
| Restricted common units forfeited in November 2005 | | (30,021) | | | | |
| **Balance, December 31, 2005** | 389,109,564 | 751,604 | - | - | - | - |

## Accumulated Other Comprehensive Income (Loss)

The following table summarizes transactions affecting our accumulated other comprehensive income (loss) since December 31, 2002.

| | Commodity Financial Instruments | Interest Rate Fin. Instrs. Treasury Locks | Interest Rate Fin. Instrs. Forward-Starting Interest Rate Swaps | Accumulated Other Comprehensive Income (Loss) Balance |
|---|---|---|---|---|
| **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 interest rate financial instruments | | (418) | (857) | (1,275) |
| **Balance, December 31, 2004** | 1,434 | 4,572 | 18,548 | 24,554 |
| Change in fair value of commodity financial instruments | (1,434) | | | (1,434) |
| Reclassification of gain on settlement of interest rate financial instruments | | (445) | (3,603) | (4,048) |
| **Balance, December 31, 2005** | $ - | $ 4,127 | $ 14,945 | $ 19,072 |

During the first quarter of 2005, we reclassified into income a $1.4 million gain related to a commodity cash flow hedge we acquired in connection with the GulfTerra Merger. This gain resulted from an increase in fair value of the underlying financial instrument from the value recorded for the commodity cash flow hedge at September 30, 2004. In 2006, we expect to reclassify $4.3 million of accumulated other comprehensive income that was generated by treasury lock and forward-starting interest rate swap transactions to reduce interest expense.

## 16. Distributions to Partners

We expect, to the extent there is sufficient cash available from Operating Surplus (as defined by our 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 Products GP's percentage interest in our quarterly cash distributions is increased after certain specified target levels of distribution rates are met. Enterprise Products GP's quarterly incentive distribution thresholds are as follows:

- 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 paid incentive distributions to Enterprise Products GP of $63.9 million, $32.4 million and $19.7 million in 2005, 2004 and 2003, respectively.

The following table presents our quarterly cash distribution rates per unit paid to common unitholders since the first quarter of 2003 and the related record and distribution payment dates.

| | Cash Distribution History | | |
|---|---|---|---|
| | Distribution per Unit (1) | Record Date | Payment Date |
| **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. 6, 2004 |
| 3rd Quarter | $0.3950 | Oct. 29, 2004 | Nov. 5, 2004 |
| 4th Quarter | $0.4000 | Jan. 31, 2005 | Feb. 14, 2005 |
| **2005** | | | |
| 1st Quarter | $0.4100 | Apr. 29, 2005 | May 10, 2005 |
| 2nd Quarter | $0.4200 | Jul. 29, 2005 | Aug. 10, 2005 |
| 3rd Quarter | $0.4300 | Oct. 31, 2005 | Nov. 8, 2005 |
| 4th Quarter | $0.4375 | Jan. 31, 2006 | Feb. 9, 2006 |

(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 rates per unit shown in the preceding table correspond to the cash flows for the quarters indicated. The actual cash distributions are paid within 45 days after the end of such quarter.

## 17. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology employed) and products produced and/or sold.

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: (i) depreciation and amortization expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) 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 intersegment and intrasegment transactions.

Segment revenues and operating costs 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 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. 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.

Our consolidated revenues were earned in the United States and derived from a wide customer base. Currently, our plant-based operations are located primarily in Texas, Louisiana, Mississippi and New Mexico. Our natural gas, NGL and crude oil pipelines 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 and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

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 the total value of segment assets is construction-in-progress. Segment assets represent the net carrying value of facilities and projects that contribute to the gross operating margin of a particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from the segment asset 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:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Revenues [1] | $ 12,256,959 | $ 8,321,202 | $ 5,346,431 |
| Less: Operating costs and expenses [1] | (11,546,225) | (7,904,336) | (5,046,777) |
| Add: Equity in income (loss) of unconsolidated affiliates [1] | 14,548 | 52,787 | (13,960) |
| Depreciation and amortization in operating costs and expenses [2] | 413,441 | 193,734 | 115,643 |
| Retained lease expense, net in operating expenses allocable to us and minority interest [3] | 2,112 | 7,705 | 9,094 |
| Gain on sale of assets in operating costs and expenses [2] | (4,488) | (15,901) | (16) |
| Total segment gross operating margin | $ 1,136,347 | $ 655,191 | $ 410,415 |

(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:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Total segment gross operating margin | $ 1,136,347 | $ 655,191 | $ 410,415 |
| Adjustments to reconcile total segment gross operating margin to operating income: | | | |
| Depreciation and amortization in operating costs and expenses | (413,441) | (193,734) | (115,643) |
| Retained lease expense, net in operating costs and expenses | (2,112) | (7,705) | (9,094) |
| Gain on sale of assets in operating costs and expenses | 4,488 | 15,901 | 16 |
| General and administrative costs | (62,266) | (46,659) | (37,590) |
| Consolidated operating income | 663,016 | 422,994 | 248,104 |
| Other expense | (225,178) | (153,625) | (134,406) |
| Income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles | $ 437,838 | $ 269,369 | $ 113,698 |

Information by segment, together with reconciliations to the consolidated totals, is presented in the following table:

| | Operating Segments | | | | | | |
|---|---|---|---|---|---|---|---|
| | Offshore Pipelines & Services | Onshore Natural Gas Pipelines & Services | NGL Pipelines & Services | Petrochemical Services | Non-Segmt. Other | Adjustments and Eliminations | Consolidated Totals |
| **Revenues from third parties:** | | | | | | | |
| Year ended December 31, 2005 | $ 110,100 | $ 1,198,320 | $ 9,006,730 | $ 1,587,037 | | | $ 11,902,187 |
| 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 | 3,654,577 | 782,999 | | | 4,782,187 |
| **Revenues from related parties:** | | | | | | | |
| Year ended December 31, 2005 | 696 | 337,282 | 16,689 | 105 | | | 354,772 |
| Year ended December 31, 2004 | 535 | 253,194 | 534,279 | 16,142 | | | 804,150 |
| Year ended December 31, 2003 | | 227,973 | 325,377 | 10,894 | | | 564,244 |
| **Intersegment and intrasegment revenues:** | | | | | | | |
| Year ended December 31, 2005 | 1,353 | 41,576 | 3,334,763 | 346,458 | | $ (3,724,150) | |
| 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) | |
| **Total revenues:** | | | | | | | |
| Year ended December 31, 2005 | 112,149 | 1,577,178 | 12,358,182 | 1,933,600 | | (3,724,150) | 12,256,959 |
| 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 |
| **Equity in income (loss) in unconsolidated affiliates:** | | | | | | | |
| Year ended December 31, 2005 | 6,125 | 2,384 | 5,553 | 486 | | | 14,548 |
| 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) |
| **Gross operating margin by individual business segment and in total:** | | | | | | | |
| Year ended December 31, 2005 | 77,505 | 353,076 | 579,706 | 126,060 | | | 1,136,347 |
| 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 |
| **Segment assets:** | | | | | | | |
| At December 31, 2005 | 632,222 | 3,622,318 | 3,075,048 | 504,841 | | 854,595 | 8,689,024 |
| At December 31, 2004 | 648,181 | 3,729,650 | 2,753,934 | 469,327 | | 230,375 | 7,831,467 |
| **Investments in and advances to unconsolidated affiliates (see Note 11):** | | | | | | | |
| At December 31, 2005 | 316,844 | 4,644 | 130,376 | 20,057 | | | 471,921 |
| At December 31, 2004 | 319,463 | 5,251 | 173,883 | 20,567 | | | 519,164 |
| **Intangible Assets (see Note 13):** | | | | | | | |
| At December 31, 2005 | 174,532 | 413,843 | 275,778 | 49,473 | | | 913,626 |
| At December 31, 2004 | 200,047 | 446,267 | 282,963 | 51,324 | | | 980,601 |
| **Goodwill (see Note 13):** | | | | | | | |
| At December 31, 2005 | 82,386 | 282,997 | 54,960 | 73,690 | | | 494,033 |
| At December 31, 2004 | 62,348 | 290,397 | 32,763 | 73,690 | | | 459,198 |

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 in September 2004. The value of total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. The operating results of entities and assets we acquire are included in our financial results prospectively from their purchase dates.

Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 67% of total consolidated revenues for each of 2005 and 2004, and 68% of total consolidated revenues for 2003. Revenues from the sale of petrochemical products within the Petrochemical Services segment accounted for 11%, 13% and 12% of total consolidated revenues for 2005, 2004 and 2003, respectively. Revenues from the transportation, sale and storage of natural gas using onshore assets accounted for 13%, 10% and 11% of total consolidated revenues for 2005, 2004 and 2003, respectively.

## 18. Related Party Transactions

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

| | For Year Ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| **Revenues from consolidated operations** | | | |
| EPCO and affiliates | $ 311 | $ 2,697 | $ 4,241 |
| Shell | | 542,912 | 293,109 |
| Unconsolidated affiliates | 354,461 | 258,541 | 266,894 |
| Total | $ 354,772 | $ 804,150 | $ 564,244 |
| **Operating costs and expenses** | | | |
| EPCO and affiliates | $ 293,134 | $ 203,100 | $ 149,915 |
| Shell | | 725,420 | 607,277 |
| Unconsolidated affiliates | 23,563 | 37,587 | 43,752 |
| Total | $ 316,697 | $ 966,107 | $ 800,944 |
| **General and administrative expenses** | | | |
| EPCO and affiliates | $ 40,954 | $ 29,307 | $ 28,716 |

Historically, Shell was considered a related party because it owned more than 10% of our limited partner interests and, prior to 2003, held a 30% membership interest in Enterprise Products GP. As a result of Shell selling a portion of its limited partner interests in us to third parties, Shell owned less than 10% of our common units at the beginning of 2005. Shell sold its 30% interest in Enterprise Products GP to an affiliate of EPCO in September 2003. As a result of Shell's reduced equity interest in us and its lack of control of Enterprise Products GP, Shell ceased to be considered a related party in January 2005.

### Relationship with EPCO and Affiliates

_General_. We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities:

- EPCO and its private company subsidiaries;
- Enterprise Products GP, our sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner;
- the Employee Partnership; and
- TEPPCO Partners, L.P. ("TEPPCO") and its general partner ("TEPPCO GP"), which are controlled by affiliates of EPCO.

Unless noted otherwise, our agreements with EPCO are not the result of arm's length transactions. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

We were formed in 1998 to own and operate certain NGL assets contributed to us by EPCO. EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise Products GP. 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.

At December 31, 2005, EPCO and its affiliates beneficially owned 144,055,494 (or 36.2%) of our outstanding common units. In January 2005, an affiliate of EPCO acquired 13,454,498 of our common units and a 9.9% membership interest in our general partner from El Paso for approximately $425 million in cash. As a result of this transaction and until August 2005, EPCO and certain of its affiliates owned 100% of the membership interests of our general partner and El Paso no longer owned any limited or general partner interest in us.

In August 2005, affiliates of EPCO contributed their 100% membership interests in our general partner and the 13,454,498 of our common units they acquired from El Paso to Enterprise GP Holdings, another affiliate of EPCO. As a result of this contribution, Enterprise GP Holdings owns 100% of the membership interests of our general partner and an approximate 3.4% limited partner interest in us. Enterprise GP Holdings is a publicly traded limited partnership that completed an initial public offering of its common units in August 2005, and its only cash generating assets consist of its general and limited partnership interests in us. At December 31, 2005, EPCO and its affiliates owned 86.5% of Enterprise GP Holdings, including 100% of EPE Holdings, LLC ("EPE Holdings"), the general partner of Enterprise GP Holdings.

The principal business activity of Enterprise Products GP is to act as our managing partner. The executive officers and certain of the directors of Enterprise Products GP and Enterprise GP Holdings are employees of EPCO. Apart from the rights it owns with respect to its general partner interest in us, Enterprise Products GP does not receive any compensation for its services to us as general partner. Enterprise Products GP received $76.8 million, $40.4 million and $25.7 million of cash distributions from us in connection with its general partner interest during 2005, 2004 and 2003, respectively. The foregoing distributions for 2005, 2004 and 2003 include $63.9 million, $32.4 million and $19.7 million of incentive distributions. See Note 16 for information regarding our distribution policy.

We and Enterprise Products GP are both separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO depends on the cash distributions it receives from us, Enterprise GP Holdings and other investments to fund its other operations and to meet its debt obligations. EPCO and its affiliates received $243.9 million, $189.8 million and $176.8 million in cash distributions from us during 2005, 2004 and 2003, respectively, in connection with its limited and general partnership interests in us.

The ownership interests in us and Enterprise Products GP that are owned or controlled by EPCO and its affiliates, other than Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of an EPCO affiliate. EPCO's credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, us and TEPPCO. In the event of a default under such credit facility, a change in control of us or our general partner could occur.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. During 2005, we paid this affiliate $17.6 million for such services. In addition, we buy from and sell certain NGL products to another affiliate of EPCO at market-related prices in the normal course of business. During 2005, our revenues from this affiliate were $0.3 million and our purchases from this affiliate were $61 million.

We also lease office space in various buildings from affiliates of EPCO related to our corporate headquarters in Houston, Texas. During 2005, our operating lease expense recorded in connection with these agreements was $3.3 million. The rental rates in these agreements approximate market rates.

*Relationship with TEPPCO*. In February 2005, an affiliate of EPCO acquired 100% of the membership interests of TEPPCO GP and 2,500,000 common units of TEPPCO for approximately $1.2 billion in cash. TEPPCO GP owns a 2% general partner interest in TEPPCO and is the managing partner of TEPPCO and its subsidiaries. In June 2005, the employees of TEPPCO became EPCO employees. We paid $17.2 million to TEPPCO during 2005 for NGL pipeline transportation and storage services. In addition, certain directors of Enterprise Products GP and Enterprise GP Holdings (Messrs. Bachmann, Creel and Fowler) were elected as additional directors of TEPPCO GP in February 2006.

In March 2005, the Bureau of Competition of the FTC delivered written notice to EPCO's legal advisor that it was conducting a non-public investigation to determine whether EPCO's acquisition of TEPPCO GP may tend substantially to lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with EPCO's purchase of TEPPCO GP. EPCO and its affiliates, including us, may receive similar inquiries from other regulatory authorities and we intend to cooperate fully with any such investigations and inquiries. In response to such FTC investigation or any inquiries EPCO and its affiliates may receive from other regulatory authorities, we may be required to divest certain assets.

In February 2006, we and TEPPCO entered into a letter of intent related to the formation of a joint venture to expand TEPPCO's Jonah Gas Gathering System ("the Jonah system") located in the Green River Basin in southwestern Wyoming. The proposed expansion of the Jonah system would increase the natural gas gathering and transportation capacity of the Jonah system from 1.5 Bcf/d to 2.0 Bcf/d. The letter of intent stipulates that we will be responsible for all activities related to the construction of the expansion of the Jonah system, including advancing of all expenditures necessary to plan, engineer and construct the expansion project. We estimate that total funds needed for this project will approximate $200 million and that the expansion assets will be placed in service in late 2006. The amounts we advance to complete the expansion of the Jonah system will constitute a subscription for an equity interest in the proposed joint venture. TEPPCO has the option to return to us up to 100% of the amounts we advance (i.e., the subscription amounts). If TEPPCO returns any portion of the subscription to us, the relative interests of us and TEPPCO in the new joint venture would be adjusted accordingly. The proposed joint venture arrangement will terminate without liability to either party if TEPPCO returns 100% of the advances we make in connection with the expansion project, including carrying costs and expenses.

In January 2006, we announced our intent to purchase from TEPPCO the Pioneer natural gas processing plant located in Opal, Wyoming and the rights to process natural gas originating from the Jonah and Pinedale fields in the Greater Green River Basin in Wyoming. Upon execution of definitive agreements, the receipt of all necessary regulatory approval and approvals from the boards of directors of TEPPCO and our general partner, we would purchase the Pioneer plant for $36 million and commence construction to increase its processing capacity from 275 MMcf/d to 550 MMcf/d. We expect this expansion to be completed in mid-2006.

*Employee Partnership*. In connection with the initial public offering of Enterprise GP Holdings, EPCO formed the Employee Partnership. EPCO serves as the general partner of the Employee Partnership. In connection with the closing of Enterprise GP Holdings' initial public offering, EPCO Holdings, Inc., a wholly-owned subsidiary of EPCO, borrowed $51 million under its credit facility and contributed the borrowings to its wholly-owned subsidiary, Duncan Family Interests, Inc. ("Duncan Family Interests"), which, in turn, contributed $51 million to the Employee Partnership as a capital contribution with respect to its Class A limited partner interest. The Employee Partnership used the contributed funds to purchase 1,821,428 units directly from Enterprise GP Holdings at the initial public offering price. Certain EPCO employees, including all of Enterprise Products GP's executive officers other than the Chairman, have been issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of the Employee Partnership.

Unless otherwise agreed to by EPCO, Duncan Family Interests and a majority in interest of the Class B limited partners of the Employee Partnership, the Employee Partnership will terminate at the earlier of five years following the closing of Enterprise GP Holdings' initial public offering or a change in control of Enterprise GP Holdings or its general partner. The Employee Partnership has the following material terms with respect to distributions:

- *Distributions of Cash Flow* – Each quarter, 100% of the distributions from units held by the Employee Partnership will be distributed to Duncan Family Interests until it has received the Class A preferred return (as defined below), and any remaining distributions from the Employee Partnership will be distributed to the Class B limited partners. The Class A preferred return will equal 1.5625% per quarter, or 6.25% per annum, of Duncan Family Interest's capital base. Duncan Family Interest's capital base will equal $51 million, increased by any unpaid Class A preferred return from prior periods, and decreased by any distributions of sale proceeds to Duncan Family Interests as described below.

- *Liquidating Distributions* – Upon liquidation of the Employee Partnership, units having a fair market value equal to Duncan Family Interest's capital base will be distributed to Duncan Family Interests, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

- *Sale Proceeds* – If the Employee Partnership sells any units, the sale proceeds will be distributed to Duncan Family Interests and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in the Employee Partnership that are owned by EPCO employees are subject to forfeiture if the participating employee's employment with EPCO and its affiliates is terminated prior to the fifth anniversary of the closing of Enterprise GP Holdings' initial public offering, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in the Employee Partnership will also lapse upon certain change of control events.

Enterprise Products Partners and Enterprise Products GP will not reimburse EPCO, the Employee Partnership or any of their affiliates or partners, through the administrative services agreement or otherwise, for any expenses related to the

Employee Partnership or the contribution of $51 million to the Employee Partnership or the purchase of the units by the Employee Partnership.

For the period that the Employee Partnership was in existence during 2005, EPCO accounted for this share-based compensation arrangement using APB 25. Under APB 25, the value of the Class B limited partner interests was accounted for in a manner similar to stock appreciation rights. EPCO's non-cash compensation expense related to this arrangement is allocated to us and other affiliates of EPCO based on our usage of each employee's services. During 2005, we recorded $2 million of non-cash compensation expense associated with the Employee Partnership. For additional information regarding our equity awards, see Note 5.

*Administrative Services Agreement*. We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement ("ASA"). We and our general partner, Enterprise GP Holdings and its general partner, and TEPPCO and its general partner are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO will provide selling, general, administrative, management, engineering and operating services as may be necessary to manage and operate our business, properties and assets (in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.

- EPCO has allowed us to participate as named insureds in its overall insurance program with the associated costs being charged to us.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related-party operating lease expense, with the offset to partners' equity accounted for as a general contribution to our partnership. At December 31, 2005, the retained leases were for a cogeneration unit and approximately 100 railcars. Should we decide to exercise the purchase options associated with the retained leases, $2.3 million would be payable in 2008 and $3.1 million in 2016.

Our operating costs and expenses for 2005, 2004 and 2003 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets.

Likewise, our general and administrative costs for 2005 and 2004 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

During 2003, our reimbursement to EPCO for administrative services was facilitated by the payment of a fixed fee for costs associated with employees and functions present at our initial public offering in 1998 and on an actual basis for costs associated with employees hired in connection with our expansion activities up to that time. To the extent that the fixed fee portion of this reimbursement method was less than EPCO's actual charges for such employees, we recorded a non-cash related-party expense for the difference.

The ASA addresses potential conflicts that may arise among Enterprise Products Partners, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings and the EPCO Group, which includes EPCO and its affiliates (excluding

Enterprise Products GP, Enterprise Products Partners and its subsidiaries, Enterprise GP Holdings and EPE Holdings and TEPPCO, TEPPCO GP and their controlled affiliates). The ASA provides, among other things, that:

- If a business opportunity to acquire equity securities is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings, then Enterprise GP Holdings will have the first right to pursue such opportunity. "Equity securities" are defined to include:

    - General partner interests (or securities which have characteristics similar to general partner interests) and incentive distribution rights or similar rights in publicly traded partnerships or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

    - Incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "Non-GP Interests") provided that such Non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

  Enterprise GP Holdings will be presumed to desire to acquire the equity securities until such time as EPE Holdings advises the EPCO Group and Enterprise Products GP that Enterprise GP Holdings has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to exceed $100 million, the decision to decline the acquisition will be made by the Chief Executive Officer of EPE Holdings after consultation with and subject to the approval of the Audit and Conflicts Committee of EPE Holdings. If the purchase price is reasonably likely to be less than such threshold amount, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the Audit and Conflicts Committee of EPE Holdings. In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group and Enterprise Products GP, Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to desire to acquire the equity securities until such time as Enterprise Products GP advises the EPCO Group that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing Enterprise Products GP's Chief Executive Officer and Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the acquisition and so notifies the EPCO Group, the EPCO Group may pursue the acquisition without any further obligation to any other party or offer such opportunity to other affiliates.

- If any business opportunity not covered by the preceding bullet point is presented to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings, Enterprise Products Partners will have the first right to pursue such opportunity. Enterprise Products Partners will be presumed to desire to pursue the business opportunity until such time as Enterprise Products GP advises the EPCO Group and EPE Holdings that Enterprise Products Partners has abandoned the pursuit of such business opportunity. In the event that the purchase price or cost associated with the business opportunity is reasonably likely to exceed $100 million, the decision to decline the business opportunity will be made by the Chief Executive Officer of Enterprise Products GP after consultation with and subject to the approval of the Audit and Conflicts Committee of Enterprise Products GP. If the purchase price or cost is reasonably likely to be less than such threshold amount, the Chief Executive Officer of Enterprise Products GP may make the determination to decline the business opportunity without consulting Enterprise Products GP's Audit and Conflicts Committee. In the event that Enterprise Products Partners abandons the business opportunity and so notifies the EPCO Group and EPE Holdings, Enterprise GP Holdings will have the second right to the pursue such business opportunity. Enterprise GP Holdings will be presumed to desire to pursue such business opportunity until such time as EPE Holdings advises the EPCO Group that Enterprise GP Holdings has abandoned the pursuit of such business opportunity. In determining whether or not to pursue the business opportunity, Enterprise GP Holdings will follow the same procedures applicable to Enterprise Products Partners, as described above but utilizing EPE Holdings' Chief Executive Officer and Audit and Conflicts Committee. In the event that Enterprise GP Holdings abandons the business opportunity and so notifies the EPCO

Group, the EPCO Group may pursue the business opportunity without any further obligation to any other party or offer such opportunity to other affiliates.

None of the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings have any obligation to present business opportunities to TEPPCO, TEPPCO GP or their controlled affiliates, and TEPPCO, TEPPCO GP and their controlled affiliates have no obligation to present business opportunities to the EPCO Group, Enterprise Products GP, Enterprise Products Partners, EPE Holdings or Enterprise GP Holdings.

The ASA also outlines an overall corporate governance structure and provides policies and procedures to address potential conflicts of interest among the parties to the ASA, including protection of the confidential information of each party from the other parties and the sharing of EPCO employees between the parties. Specifically, the ASA provides, among other things, that:

- There shall be no overlap in the independent directors of Enterprise Products GP, EPE Holdings and TEPPCO GP;

- There shall be no sharing of EPCO employees performing commercial and development activities involving certain defined potential overlapping assets between us, Enterprise GP Holdings, and EPCO and its other affiliates (excluding TEPPCO and subsidiaries) on one hand and TEPPCO and its subsidiaries and TEPPCO GP on the other hand; and

- Certain screening procedures are to be followed if an EPCO employee performing commercial and development activities becomes privy to commercial information relating to a potential overlapping asset of any entity for which such employee does not perform commercial and development activities.

### Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 17 for a discussion of this alignment of commercial interests. The following information summarizes significant related-party transactions 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. Revenues from Evangeline were $318.8 million, $233.9 million and $212.7 million for 2005, 2004 and 2003, respectively. In addition, we have furnished $1.2 million in letters of credit on behalf of Evangeline at December 31, 2005.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Expenses with Promix were $26 million, $23.2 million and $17.5 million for 2005, 2004 and 2003, respectively. Additionally, revenues from Promix were $25.8 million, $18.6 million and $19.6 million for 2005, 2004 and 2003, respectively.

- We perform management services for certain of our unconsolidated affiliates. These fees were $8.3 million, $2.1 million and $1.5 million for 2005, 2004 and 2003, respectively.

### Relationship with Shell

In 2004 and 2003, 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.

In connection with our March 2005 universal registration statement, we registered for resale 35,368,522 common units owned by Shell and 5,631,478 common units owned by a third party, Kayne Anderson MLP Investment Company, which had been acquired from Shell. We were obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our September 1999 acquisition of certain assets of Shell's Gulf Coast midstream energy business.

## 19. Provision for Income Taxes for Certain Pipeline Operations

Our provision for income taxes relates to federal income tax and state franchise and income tax obligations of Seminole and Dixie, which are both corporations and represent our only consolidated subsidiaries subject to such income taxes. Our federal and state income tax provision is summarized below:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Current: | | | |
| Federal | $ 1,105 | | |
| State | 301 | $ 157 | $ 47 |
| Total current | 1,406 | 157 | 47 |
| Deferred: | | | |
| Federal | 5,968 | 1,620 | 4,556 |
| State | 988 | 1,984 | 690 |
| Total deferred | 6,956 | 3,604 | 5,246 |
| Total provision for income taxes | $ 8,362 | $ 3,761 | $ 5,293 |

A reconciliation of the provision for income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes of these subsidiaries is as follows:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Taxes computed by applying the federal statutory rate | $ 7,656 | $ 2,308 | $ 4,811 |
| State income taxes (net of federal benefit) | 838 | 1,392 | 479 |
| Tax benefit charged to cumulative effect of change in accounting principle | 65 | | |
| Other permanent differences | (197) | 61 | 3 |
| Provision for income taxes | $ 8,362 | $ 3,761 | $ 5,293 |
| Effective income tax rate | 38% | 57% | 39% |

The deferred tax asset shown on our consolidated balance sheet reflects the net tax effects of temporary differences between the subsidiary's carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The significant components of our deferred tax asset are as follows:

| | At December 31, | |
|---|---|---|
| | 2005 | 2004 |
| Deferred Tax Assets: | | |
| Property, plant and equipment – Dixie | $ 855 | |
| Net operating loss carryforwards | 14,251 | $ 11,735 |
| Employee benefit plans | 2,403 | |
| Deferred revenue | 448 | 520 |
| Accruals | 116 | |
| Total Deferred Tax Assets | 18,073 | 12,255 |
| Deferred Tax Liabilities: | | |
| Property, plant and equipment – Seminole | 13,907 | 5,269 |
| Other | 6 | |
| Total Deferred Tax Liabilities | 13,913 | 5,269 |
| Net Deferred Tax Assets | $ 4,160 | $ 6,986 |
| | | |
| Current portion of deferred tax assets | $ 554 | $ 519 |
| Long-term portion of deferred tax assets | $ 3,606 | $ 6,467 |

## 20. 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 (excluding restricted units) outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of time-vested and performance-based restricted common units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

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 2004. 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 in 2003.

Treasury units were not considered to be outstanding units; therefore, they were excluded from the computation of both basic and diluted earnings per unit.

In a period of net operating losses, the restricted units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. 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 end 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.

The amount of net income or loss allocated to limited partner interests is net of our general partner's share of such earnings. The following table shows the allocation of net income to our general partner for the periods indicated:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | **2005** | **2004** | **2003** |
| Net income | $ 419,508 | $ 268,261 | $ 104,546 |
| Less incentive earnings allocations to Enterprise Products GP | (63,884) | (32,391) | (19,699) |
| Net income available after incentive earnings allocation | 355,624 | 235,870 | 84,847 |
| Multiplied by Enterprise Products GP ownership interest (1) | 2.0% | 2.0% | 1.2% |
| Standard earnings allocation to Enterprise Products GP | $ 7,112 | $ 4,717 | $ 1,030 |
| | | | |
| Incentive earnings allocation to Enterprise Products GP | $ 63,884 | $ 32,391 | $ 19,699 |
| Standard earnings allocation to Enterprise Products GP | 7,112 | 4,717 | 1,030 |
| Enterprise Products GP interest in net income | $ 70,996 | $ 37,108 | $ 20,729 |

(1) Enterprise Products 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. The 1.2% ownership interest shown for 2003 reflects the weighted-average of the Enterprise Products GP's ownership interest during the year.

The following table presents our calculation of basic and diluted earnings per unit for the periods shown:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Income before changes in accounting principles and Enterprise Products GP interest | $ 423,716 | $ 257,480 | $ 104,546 |
| Cumulative effect of changes in accounting principles | (4,208) | 10,781 | |
| Net income | 419,508 | 268,261 | 104,546 |
| Enterprise Products GP interest in net income | (70,996) | (37,108) | (20,729) |
| Net income available to limited partners | $ 348,512 | $ 231,153 | $ 83,817 |
| **BASIC EARNINGS PER UNIT** | | | |
| **Numerator** | | | |
| Income before changes in accounting principles and Enterprise Products GP interest | $ 423,716 | $ 257,480 | $ 104,546 |
| Cumulative effect of changes in accounting principles | (4,208) | 10,781 | |
| Enterprise Products GP interest in net income | (70,996) | (37,108) | (20,729) |
| Limited partners' interest in net income | $ 348,512 | $ 231,153 | $ 83,817 |
| **Denominator** | | | |
| Common units | 381,857 | 262,838 | 183,779 |
| Subordinated units | | | 15,955 |
| Class B special units | | 2,532 | 181 |
| Total | 381,857 | 265,370 | 199,915 |
| **Basic earnings per unit** | | | |
| Income before changes in accounting principles and Enterprise Products GP interest | $ 1.11 | $ 0.97 | $ 0.52 |
| Cumulative effect of changes in accounting principles | (0.01) | 0.04 | |
| Enterprise Products GP interest in net income | (0.19) | (0.14) | (0.10) |
| Limited partners' interest in net income | $ 0.91 | $ 0.87 | $ 0.42 |
| **DILUTED EARNINGS PER UNIT** | | | |
| **Numerator** | | | |
| Income before changes in accounting principles and Enterprise Products GP interest | $ 423,716 | $ 257,480 | $ 104,546 |
| Cumulative effect of changes in accounting principles | (4,208) | 10,781 | |
| Enterprise Products GP interest in net income | (70,996) | (37,108) | (20,729) |
| Limited partners' interest in net income | $ 348,512 | $ 231,153 | $ 83,817 |
| **Denominator** | | | |
| Common units | 381,857 | 262,838 | 183,779 |
| Subordinated units | | | 15,955 |
| Class A special units | | | 5,808 |
| Class B special units | | 2,532 | 181 |
| Time-vested restricted units | 606 | 141 | |
| Performance-based restricted units | 45 | 14 | |
| Series F2 convertible units | | 22 | |
| Incremental option units | 455 | 498 | 644 |
| Total | 382,963 | 266,045 | 206,367 |
| **Diluted earnings per unit** | | | |
| Income before changes in accounting principles and Enterprise Products GP interest | $ 1.11 | $ 0.97 | $ 0.51 |
| Cumulative effect of changes in accounting principles | (0.01) | 0.04 | |
| Enterprise Products GP interest in net income | (0.19) | (0.14) | (0.10) |
| Limited partners' interest in net income | $ 0.91 | $ 0.87 | $ 0.41 |

## 21. Commitments and Contingencies

### Litigation

On occasion, we are named as a defendant in litigation relating to our normal business operations, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe 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 our ordinary business activity. We are not aware of any significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

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 that 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. In connection with our purchase of additional equity interests in the owner of the octane-additive production facility in 2003 from an affiliate of Devon Energy Corporation ("Devon") and in 2004 from an affiliate of Sunoco, Inc. ("Sun"), Devon and Sun indemnified us for any liability (including liabilities described above) that are in respect of periods prior to the date we purchased such interests. There are no dollar limits or deductibles associated with the indemnities we received from Sun and Devon with respect to potential claims linked to the period of time they held ownership interests in the facility.

### Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2005. A description of each type of contractual obligation follows.

| | Payment or Settlement due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| **Contractual Obligations** | **Total** | **2006** | **2007** | **2008** | **2009** | **2010** | **Thereafter** |
| Scheduled maturities of long-term debt | $ 4,866,068 | | $ 517,000 | | $ 500,000 | $1,049,068 | $ 2,800,000 |
| Operating lease obligations | $ 179,623 | $ 19,099 | $ 18,638 | $ 15,210 | $ 10,352 | $ 9,737 | $ 106,587 |
| Purchase obligations: | | | | | | | |
| Product purchase commitments: | | | | | | | |
| Estimated payment obligations: | | | | | | | |
| Natural gas | $ 1,518,016 | $ 216,690 | $ 216,690 | $ 217,283 | $ 216,690 | $ 216,690 | $ 433,973 |
| NGLs | $ 6,095,907 | $ 684,250 | $ 619,048 | $ 499,900 | $ 499,900 | $ 499,900 | $ 3,292,909 |
| Petrochemicals | $ 1,290,952 | $ 1,079,110 | $ 159,511 | $ 52,331 | | | |
| Other | $ 87,162 | $ 31,578 | $ 23,176 | $ 21,548 | $ 10,712 | $ 148 | |
| Underlying major volume commitments: | | | | | | | |
| Natural gas (in BBtus) | 127,850 | 18,250 | 18,250 | 18,300 | 18,250 | 18,250 | 36,550 |
| NGLs (in MBbls) | 63,130 | 9,251 | 7,741 | 5,086 | 5,086 | 5,086 | 30,880 |
| Petrochemicals (in MBbls) | 19,717 | 16,525 | 2,381 | 811 | | | |
| Service payment commitments | $ 5,765 | $ 5,037 | $ 689 | $ 39 | | | |
| Capital expenditure commitments | $ 208,575 | $ 208,575 | | | | | |

*Scheduled Maturities of Long-Term Debt.* We have long and short-term payment obligations under debt agreements such as the indentures governing our Operating Partnership's senior notes and the credit agreement governing our Operating Partnership's Multi-Year Revolving Credit Facility. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated. See Note 14 for additional information regarding our consolidated debt obligations.

*Operating Lease Obligations.* We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year for the periods indicated.

Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs; (ii) leased office space with an affiliate of EPCO; and (iii) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 14 to 20 years and include renewal options that could extend the agreements for up to an additional 20 years. Our rental payments under these agreements are generally fixed rates, as specified in the individual contract, which may be subject to escalation provisions for inflation and other market-determined factors. With regards to our underground storage leases, we may also be assessed contingent rental payments when our storage volumes exceed our reserved capacity.

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. In general, we are required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during 2005, 2004 or 2003.

The operating lease commitments shown in the preceding table exclude the non-cash related-party expense associated with equipment leases contributed to us by EPCO at our formation (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2005, the retained leases were for a cogeneration unit and approximately 100 railcars. EPCO's minimum future rental payments under these leases are $2.1 million for each of the years 2006 through 2008, $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016. We record the full value of these payments made by EPCO on our behalf as a non-cash related-party operating lease expense, with the offset to partners' equity accounted for as a general contribution to our partnership.

The retained lease agreements contain lessee purchase options, which are at prices that approximate fair value of the underlying leased assets. EPCO has assigned these purchase options to us. During 2004, we exercised our option to purchase an isomerization unit and related equipment for $17.8 million. Should we decide to exercise the remaining purchase options, up to an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

Lease and rental expense included in operating income was $34.9 million, $19.5 million and $17.8 million during 2005, 2004 and 2003, respectively.

*Purchase Obligations*. 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: (i) fixed or minimum quantities to be purchased; (ii) fixed, minimum or variable price provisions; and (iii) the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

- 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. The preceding table shows 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, 2005 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2005, we do not have any product purchase commitments with fixed or minimum pricing provisions having remaining terms in excess of one year.

- We have long and short-term commitments to pay third party 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.

- Lastly, 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 purchased. Our capital expenditure commitments also include $95 million for the acquisition of certain pipeline assets during 2006. The preceding table shows these combined amounts for the periods indicated.

### Redelivery Commitments

We transport and store 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, 2005, NGL and petrochemical volumes aggregating 15.2 million barrels were due to be redelivered to their owners along with 15,512 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 18). This includes the costs associated with equity-based awards granted to these employees. At December 31, 2005, there were 2,082,000 options outstanding to purchase common units under the 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 $22.16 per common unit. At December 31, 2005, 727,000 of these unit options were exercisable. An additional 25,000, 840,000 and 490,000 of these unit options will be exercisable in 2006, 2008 and 2009, 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 5 for additional information regarding our accounting for equity awards.

### Performance Guaranty

In December 2004, a subsidiary of the Operating Partnership entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement, as amended, obligates the subsidiary (i) to construct an offshore platform production facility to process 1 Bcf/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 subsidiary under the Agreement up to $426 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 $341 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 the cost of constructing the platform in the remote scenario where the six producers take over the construction of the platform facility. This performance guarantee continues until the earlier to occur of (i) all of the guaranteed obligations of the subsidiary shall have been terminated, paid or otherwise 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 of the platform will occur in November 2006; therefore, we anticipate that the performance guaranty will exist until at least this future date.

In accordance with FIN 45, "*Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*," 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 other current liabilities on our Consolidated Balance Sheet at December 31, 2005.

## 22. Significant Risks and Uncertainties

### Nature of Operations in Midstream Energy Industry

We operate predominantly in the midstream energy industry, 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 (i) changes in the commodity prices of these hydrocarbon products and (ii) 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 beyond our 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 (i) general economic conditions; (ii) reduced demand by consumers for the end products made with NGL products; (iii) increased competition from petroleum-based products due to the pricing differences; (iv) adverse weather conditions; (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline; or (vi) other reasons, could also adversely affect our results of operations, cash flows and financial position.

### Credit Risk Due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may 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.

### Counterparty Risk with Respect to Financial Instruments

Where we are exposed to credit risk in our financial instrument transactions, 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 non-performance by our counterparties.

### Weather-Related Risks

We participate as named insureds in EPCO's current insurance program, which provides us with property damage, business interruption and other coverages, which are customary for the nature and scope of our operations. Historically, most of the insurance carriers in EPCO's portfolio of coverage were rated "A" or higher by recognized ratings agencies. The financial impact of recent storm events such as Hurricanes Katrina and Rita has resulted in the lowering of credit ratings of many insurance carriers, with a number of providers also being placed on negative credit watch. We are unaware of any of our existing carriers dropping below the "A" rating level. At present, there is no indication of any insurance carrier in the EPCO insurance program being unable or unwilling to meet its coverage obligations.

We believe that EPCO maintains adequate insurance coverage on behalf of us, although insurance will not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available for only reduced amounts of coverage. As a result, EPCO may not be able to renew existing insurance policies on behalf of us or procure other desirable insurance on commercially reasonable terms, if at all. At present, the annualized cost of insurance premiums allocated to us by EPCO for all lines of coverage is approximately $21.1 million. This amount includes a $3.7 million increase in premiums related to Hurricanes Katrina and Rita that we recognized during 2005.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to partners and, accordingly, adversely affect the market price of our common units.

The following is a discussion of the general status of insurance claims related to recent significant storm events that affected our assets. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur in the near term as additional information becomes available to us.

*Hurricane Ivan insurance claims*. Our final purchase price allocation for the GulfTerra Merger includes a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain GulfTerra assets caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004 prior to the GulfTerra Merger. These expenditures represent our total costs to restore the former GulfTerra damaged facilities to operation. Since this loss event occurred prior to completion of the GulfTerra Merger, the claim was filed under the insurance program of GulfTerra and El Paso. Since year end 2005, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million by mid-2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the fourth quarter of 2005, we received $4.8 million from such claims. In addition, we estimate an additional $15 million to $16 million will be received during the first quarter of 2006. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

*Hurricanes Katrina and Rita insurance claims*. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. Inspection and evaluation of property damage to our facilities is a continuing effort. We expensed $5 million during 2005 related to property damage insurance deductibles for these storms. To the extent that insurance proceeds from property damage claims do not cover our expenditures (in excess of the insurance deductibles we have expensed), such shortfall will be expensed when realized. We recorded $15.5 million of estimated recoveries from property damage claims based on amounts expended through December 31, 2005. In addition, we expect to file business interruption claims for losses related to these hurricanes. To the extent we receive cash proceeds from such business interruption claims, they will be recorded as a gain in our statements of consolidated operations and comprehensive income in the period of receipt.

## 23. Supplemental Cash Flow Information

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, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Decrease (increase) in: | | | |
| Accounts and notes receivable | $ (363,857) | $ (453,904) | $ (54,388) |
| Inventories | (148,846) | (44,202) | 49,932 |
| Prepaid and other current assets | (51,163) | 2,726 | 11,073 |
| Other assets | 58,762 | (6,073) | (226) |
| Increase (decrease) in: | | | |
| Accounts payable | 45,802 | 110,497 | (6,720) |
| Accrued gas payable | 349,979 | 286,089 | 128,050 |
| Accrued expenses | (161,989) | 8,800 | (16,677) |
| Accrued interest | 858 | (199) | 15,012 |
| Other current liabilities | 2,274 | 6,534 | (4,196) |
| Other liabilities | 1,785 | (3,993) | (972) |
| Net effect of changes in operating accounts | $ (266,395) | $ (93,725) | $ 120,888 |
| Cash payments for interest, net of $22,046, $2,766 and $1,595 capitalized in 2005, 2004 and 2003, respectively | $ 239,088 | $ 135,797 | $ 112,712 |
| Cash payments for federal and state income taxes | $ 5,160 | $ 182 | $ 453 |

Supplemental cash flow information regarding our investing activities related to business combinations and asset purchases in 2005, 2004 and 2003 are as follows:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Fair value of assets acquired | $ 353,176 | $ 5,946,294 | $ 127,185 |
| Less liabilities assumed | (23,940) | (2,269,893) | (70,037) |
| Net assets acquired | 329,236 | 3,676,401 | 57,148 |
| Less equity issued | | (2,910,772) | |
| Less cash acquired | (2,634) | (40,968) | (19,800) |
| Cash used for business combinations, net of cash received | $ 326,602 | $ 724,661 | $ 37,348 |

We incurred liabilities for construction in progress and property additions that had not been paid at December 31, 2005, 2004 and 2003 of $130.2 million, $62.4 million and $9.1 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

On certain of our capital projects, third parties may be obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $47 million, $8.9 million and $0.9 million as contributions in aid of our construction costs during 2005, 2004 and 2003, respectively.

Net income for 2005 includes a gain on the sale of assets of $5.5 million resulting from the sale of our 50% ownership interest in Starfish. We were required to sell our investment in Starfish in connection with gaining regulatory approval for the GulfTerra Merger.

Net income for 2004 includes a gain on sale of assets of $15.1 million resulting from the satisfaction of certain requirements of an asset sale agreement whereby we sold a 50% ownership interest in Cameron Highway to a third party. Of the $15.1 million gain we recognized, $5 million was realized in December 2004 and the remainder represents a receivable due from the third party in 2006.

In June 2005, we received $47.5 million in cash from Cameron Highway as a return of investment. These funds were distributed to us in connection with the refinancing of Cameron Highway's project debt (see Note 14).

## 24. Selected Quarterly Data (Unaudited)

The following table presents selected quarterly financial data for 2005 and 2004:

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| **For the Year Ended December 31, 2005:** (1) | | | | |
| Revenues | $ 2,555,522 | $ 2,671,768 | $ 3,249,291 | $ 3,780,378 |
| Operating income | 165,464 | 125,506 | 194,397 | 177,649 |
| Income before changes in accounting principles | 109,256 | 70,659 | 131,169 | 112,632 |
| Net income | 109,256 | 70,659 | 131,169 | 108,424 |
| Income per unit before changes in accounting principles: | | | | |
| Basic | $ 0.25 | $ 0.14 | $ 0.29 | $ 0.24 |
| Diluted | $ 0.25 | $ 0.14 | $ 0.29 | $ 0.24 |
| Net income per unit: | | | | |
| Basic | $ 0.25 | $ 0.14 | $ 0.29 | $ 0.23 |
| Diluted | $ 0.25 | $ 0.14 | $ 0.29 | $ 0.23 |
| **For the Year Ended December 31, 2004:** (1) | | | | |
| Revenues | $ 1,704,890 | $ 1,713,346 | $ 2,040,271 | $ 2,862,695 |
| Operating income | 88,783 | 66,010 | 92,917 | 175,284 |
| Income before changes in accounting principles | 51,747 | 33,148 | 57,231 | 115,354 |
| Net income | 62,528 | 33,148 | 57,231 | 115,354 |
| Income per unit before changes in accounting principles: | | | | |
| Basic | $ 0.21 | $ 0.11 | $ 0.20 | $ 0.28 |
| Diluted | $ 0.21 | $ 0.11 | $ 0.20 | $ 0.28 |
| Net income per unit: | | | | |
| Basic | $ 0.26 | $ 0.11 | $ 0.20 | $ 0.28 |
| Diluted | $ 0.26 | $ 0.11 | $ 0.20 | $ 0.28 |

(1) Our results of operations have increased since the completion of the GulfTerra Merger on September 30, 2004.

## 25. Condensed Financial Information of Operating Partnership

The Operating Partnership conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of our Operating Partnership.

We act as guarantor of all our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes, the Dixie revolving credit facility and the amounts remaining outstanding under GulfTerra's 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, unconditional and non-recourse to Enterprise Products GP. For additional information regarding our consolidated debt obligations, see Note 14.

The reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. The following table shows condensed consolidated balance sheet data for the Operating Partnership at the dates indicated:

| | December 31, | |
|---|---|---|
| | 2005 | 2004 |
| **ASSETS** | | |
| Current assets | $ 1,960,015 | $ 1,425,574 |
| Property, plant and equipment, net | 8,689,024 | 7,831,467 |
| Investments in and advances to unconsolidated affiliates | 471,921 | 519,164 |
| Intangible assets, net | 913,626 | 980,601 |
| Goodwill | 494,033 | 459,198 |
| Deferred tax asset | 3,606 | 6,467 |
| Other assets | 39,014 | 58,139 |
| Total | $ 12,571,239 | $ 11,280,610 |
| **LIABILITIES AND PARTNERS' EQUITY** | | |
| Current liabilities | $ 1,894,227 | $ 1,582,911 |
| Long-term debt | 4,833,781 | 4,266,236 |
| Other long-term liabilities | 84,486 | 63,521 |
| Minority interest | 106,159 | 73,858 |
| Partners' equity | 5,652,586 | 5,294,084 |
| Total | $ 12,571,239 | $ 11,280,610 |
| | | |
| Total Operating Partnership debt obligations guaranteed by us | $ 4,844,000 | $ 4,267,229 |

The following table shows condensed consolidated statements of operations data for the Operating Partnership for the periods indicated:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Revenues | $ 12,256,959 | $ 8,321,202 | $ 5,346,431 |
| Costs and expenses | 11,605,923 | 7,946,816 | 5,083,701 |
| Equity in income (loss) of unconsolidated affiliates | 14,548 | 52,787 | (13,960) |
| Operating income | 665,584 | 427,173 | 248,770 |
| Other income (expense) | (226,075) | (153,251) | (133,798) |
| Income before provision for income taxes, minority interest and changes in accounting principles | 439,509 | 273,922 | 114,972 |
| Provision for income taxes | (8,362) | (3,761) | (5,293) |
| Income before minority interest and changes in accounting principles | 431,147 | 270,161 | 109,679 |
| Minority interest | (5,989) | (8,072) | (3,095) |
| Income before changes in accounting principles | 425,158 | 262,089 | 106,584 |
| Cumulative effect of changes in accounting principles | (4,208) | 10,781 | |
| Net income | $ 420,950 | $ 272,870 | $ 106,584 |

# Market and Cash Distribution History for Common Units and Related Unitholder Matters

## Market Information and Cash Distributions

Our common units are listed on the NYSE under the ticker symbol "EPD". As of February 15, 2006, there were an estimated 920 unitholders of record of our common units. The following table sets forth the high and low sales prices for our common units during the periods indicated (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units.

| | Price Ranges | | Cash Distribution History | | |
|---|---|---|---|---|---|
| | High | Low | Per Unit | Record Date | Payment Date |
| **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. 6, 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 |
| **2005** | | | | | |
| 1st Quarter | $28.350 | $23.920 | $0.4100 | Apr. 29, 2005 | May 10, 2005 |
| 2nd Quarter | $27.090 | $24.770 | $0.4200 | Jul. 29, 2005 | Aug. 10, 2005 |
| 3rd Quarter | $27.660 | $23.500 | $0.4300 | Oct. 31, 2005 | Nov. 8, 2005 |
| 4th Quarter | $26.020 | $23.380 | $0.4375 | Jan. 31, 2006 | Feb. 9, 2006 |

The quarterly cash distributions shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our partners) occur within 45 days after the end of such quarter. 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 "*Liquidity and Capital Resources*". Although the payment of cash dividends is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

## Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2005.

## Common Units Authorized for Issuance Under Equity Compensation Plan

Please read the information included under Item 12 on Page 165 of Enterprise's 2005 Form 10-K.

## Issuer Purchases of Equity Securities

We did not repurchase any of our common units during 2005. In December 1998, we announced a common unit 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 2-for-1 unit split in May 2002). As of February 15, 2006, we and our affiliates are authorized to repurchase up to 618,400 additional common units under this repurchase program.

## Employees

At December 31, 2005, there were approximately 2,600 persons directly involved in the management, administration and operations of Enterprise Products Partners, approximately 2,365 of which are employees of EPCO that provide services to us under an administrative services agreement. The remaining 235 individuals primarily represent third party contract personnel.

## New York Stock Exchange Compliance

On April 5, 2006 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, 2005 as filed with the Securities and Exchange Commission on February 27, 2006.

## Cautionary Statement Regarding Forward-Looking Information

This annual report contains various forward-looking statements and information that are based on our beliefs and those of Enterprise Products GP, 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 Enterprise Products GP believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor Enterprise Products 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.

## Glossary

The following terms, which are used in the energy industry and in this annual report, have the following meanings:

| | | |
|---|---|---|
| /d | = | per day |
| BBtus | = | billion British Thermal units |
| Bcf | = | billion cubic feet |
| MBPD | = | thousand barrels per day |
| Mdth | = | thousand dekatherms |
| MMBBls | = | million barrels |
| MMBtus | = | million British Thermal units |
| MMcf | = | million cubic feet |
| Mcf | = | thousand cubic feet |

# Reconciliation of GAAP Financial Statements to Non-GAAP Financial Measures

| | For Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2005 | 2004 | 2003 | 2002 | 2001 |
| *Reconciliation of Non-GAAP "EBITDA" to GAAP "Net Income" and GAAP "Net Cash Provided by Operating Activities"* | | | | | |
| **Net Income** | $ 419,508 | $ 268,261 | $ 104,546 | $ 95,500 | $ 242,178 |
| Adjustments to reconcile EBITDA to Net Income: | | | | | |
| Interest expense | 230,549 | 155,740 | 140,806 | 101,580 | 52,456 |
| Provision for income taxes | 8,362 | 3,761 | 5,293 | 1,634 | |
| Depreciation and amortization (excluding amortization component in interest expense) | 420,625 | 195,384 | 115,801 | 86,106 | 51,116 |
| **EBITDA** | $ 1,079,044 | $ 623,146 | $ 366,446 | $ 284,820 | $ 345,750 |
| *Reconciliation of "EBITDA" to "Net Cash Provided by Operating Activities":* | | | | | |
| Interest expense | (230,549) | (155,740) | (140,806) | (101,580) | (52,456) |
| Amortization in interest expense | 152 | 3,503 | 12,634 | 8,819 | 787 |
| Provision for income taxes | (8,362) | (3,761) | (5,293) | (1,634) | |
| Equity in (income) loss of unconsolidated affiliates | (14,548) | (52,787) | 13,960 | (35,253) | (25,358) |
| Distributions from unconsolidated affiliates | 56,058 | 68,027 | 31,882 | 57,662 | 45,054 |
| Gain on sale of assets | (4,488) | (15,901) | (16) | (1) | (390) |
| Provision for impairment of long-lived asset | | 4,114 | 1,200 | | |
| Cumulative effect of changes in accounting principles | 4,208 | (10,781) | | | |
| Operating lease expense paid by EPCO (excluding minority interest portion) | 2,112 | 7,705 | 9,010 | 9,033 | 10,309 |
| Other expenses paid by EPCO (excluding minority interest portion) | | | 436 | | |
| Minority interest | 5,760 | 8,128 | 3,859 | 2,947 | 2,472 |
| Deferred income tax expense | 8,594 | 9,608 | 10,534 | 2,080 | |
| Changes in fair market value of financial instruments | 122 | 5 | (29) | 10,213 | (5,697) |
| Net effect of changes in operating accounts | (266,395) | (93,725) | 120,888 | 92,655 | (37,143) |
| **Net Cash Provided by Operating Activities** | $ 631,708 | $ 391,541 | $ 424,705 | $ 329,761 | $ 283,328 |
| *Reconciliation of Non-GAAP "Distributable Cash Flow" to GAAP "Net Income" and GAAP "Net Cash Provided by Operating Activities"* | | | | | |
| **Net Income** | $ 419,508 | $ 268,261 | $ 104,546 | $ 95,500 | $ 242,178 |
| Adjustments to reconcile Distributable Cash Flow to Net Income: | | | | | |
| Operating lease expense paid by EPCO (excluding minority interest portion) | 2,112 | 7,705 | 9,010 | 9,033 | 10,309 |
| Other expenses paid by EPCO (excluding minority interest portion) | | | 436 | | |
| Cumulative effect of change in accounting principle, excluding minority interest portion | 4,208 | (8,443) | | | |
| Equity in (income) loss of unconsolidated affiliates | (14,548) | (52,787) | 13,960 | (35,253) | (25,358) |
| Distributions from unconsolidated affiliates | 56,058 | 68,027 | 31,882 | 57,662 | 45,054 |
| Deferred income tax expense | 8,594 | 9,608 | 10,534 | 2,080 | |
| Provision for impairment of asset | | 4,114 | 1,200 | | |
| Gain on sale of assets | (4,488) | (15,901) | (16) | (1) | (390) |
| Proceeds from sale of assets | 44,746 | 6,882 | 212 | 165 | 568 |
| Changes in fair market value of financial instruments | 122 | 5 | (29) | 10,213 | (5,697) |
| Depreciation and amortization | 420,777 | 198,887 | 128,435 | 94,925 | 51,903 |
| Sustaining capital expenditures | (92,158) | (37,315) | (20,313) | (7,201) | (5,994) |
| Collection of notes receivable from unconsolidated affiliates | | | | | |
| Settlement of forward-starting interest rate swaps | | 19,405 | | | |
| Amortization of net gain from forward-starting interest rate swaps | (3,602) | (857) | | | |
| 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 | 17,250 | 4,500 | | | |
| Return of investment from Cameron Highway Oil Pipeline System related to refinancing of its project debt | 47,500 | | | | |
| GulfTerra distributable cash flow for third quarter of 2004 | | 68,402 | | | |
| General Partner minority interest in net income | | | 982 | 1,071 | 2,577 |
| **Distributable Cash Flow** | $ 906,079 | $ 540,493 | $ 278,766 | $ 228,194 | $ 303,904 |
| *Reconciliation of "Distributable Cash Flow" to "Net Cash Provided by Operating Activities"* | | | | | |
| Minority interest portion of cumulative effect of change in accounting principle | | (2,338) | | | |
| Sustaining capital expenditures | 92,158 | 37,315 | 20,313 | 7,201 | 5,994 |
| Proceeds from sale of assets | (44,746) | (6,882) | (212) | (165) | (568) |
| GulfTerra distributable cash flow for third quarter of 2004 | | (68,402) | | | |
| Minority interest in total | 5,760 | 8,128 | 2,877 | 1,876 | (105) |
| Settlement of forward-starting interest rate swaps | | (19,405) | | | |
| Amortization of net gain from forward-starting interest rate swaps | 3,602 | 857 | | | |
| 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 | (17,250) | (4,500) | | | |
| Return of investment from Cameron Highway Oil Pipeline System related to refinancing of its project debt | (47,500) | | | | |
| Net effect of changes in operating accounts | (266,395) | (93,725) | 120,888 | 92,655 | (37,143) |
| **Net Cash Provided by Operating Activities** | $ 631,708 | $ 391,541 | $ 424,705 | $ 329,761 | $ 283,328 |

# Directors and Officers of Enterprise Products GP, LLC

## Directors

**Richard H. Bachmann**
*Executive Vice President,*
*Chief Legal Officer and Secretary*

**E. William Barnett (1), (2), (4)**
*Former Managing Partner,*
*Baker Botts, L.L.P.*

**Stephen L. Baum (1), (2)**
*Former Chairman and Chief*
*Executive Officer of Sempra Energy*

**Michael A. Creel**
*Executive Vice President and*
*Chief Financial Officer*

**Dr. Ralph S. Cunningham**
*Executive Vice President and*
*Chief Operating Officer*

**Dan L. Duncan**
*Chairman,*
*Enterprise Products GP, LLC*

**W. Randall Fowler**
*Senior Vice President*
*and Treasurer*

**Philip C. Jackson (1), (2), (3)**
*Former Adjunct Professor of Finance*
*Birmingham-Southern College*

**Robert G. Phillips**
*President and Chief Executive Officer,*
*Enterprise Products GP, LLC*

## Officers of Enterprise Products GP, LLC, in addition to Directors

**James H. Lytal**
*Executive Vice President*

**A.J. "Jim" Teague**
*Executive Vice President*

**Lynn L. Bourdon, III**
*Senior Vice President*

**Charles M. Brabson**
*Senior Vice President*

**James A. Cisarik**
*Senior Vice President*

**James M. Collingsworth**
*Senior Vice President*

**Charles E. Crain**
*Senior Vice President*

**Michael J. Knesek**
*Senior Vice President, Controller and*
*Principal Accounting Officer*

**Rudy A. Nix**
*Senior Vice President*

**William Ordemann**
*Senior Vice President*

**Gil H. Radtke**
*Senior Vice President*

**Thomas M. Zulim**
*Senior Vice President*

**Graham W. Bacon**
*Vice President*

**Jason A. Balasch**
*Vice President*

**John E. Bonn**
*Vice President*

**Gerald R. Cardillo**
*Vice President*

**Vincent J. Di Cosimo**
*Vice President*

**Paul G. Flynn**
*Vice President and*
*Chief Information Officer*

**James D. Gernentz**
*Vice President*

**Brad N. Graves**
*Vice President*

**Theodore Helfgott, Ph. D.**
*Vice President*

**Stephanie C. Hildebrandt**
*Vice President*

**Terrance L. Hurlburt**
*Vice President*

**Dennis A. Jahde**
*Vice President*

**Russell H. Kovin**
*Vice President*

**James N. McGrew**
*Vice President*

**Angela M. Raguso**
*Vice President*

**Gregory W. Watkins**
*Vice President*

**A. Monty Wells**
*Vice President*

**Mark D. Youtsey**
*Vice President*

(1) Member of Audit and Conflicts Committee
(2) Member of Governance Committee
(3) Chairman of Audit and Conflicts Committee
(4) Chairman of Governance Committee

# 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 389,109,564 Common Units outstanding and 751,604 Restricted Units at December 31, 2005. For a complete description of these units, see page 97. For a table of the high and low market prices of the Common Units by quarter, see page 125.

## CASH DISTRIBUTIONS

Enterprise has paid 30 consecutive quarterly cash distributions to Unitholders since its public offering of Common Units in 1998. On January 17, 2006, the Company declared a quarterly distribution of $0.4375 per unit. This distribution was paid to Unitholders of record as of January 31, 2006. For a summary of the cash distributions paid, see page 104.

## INDEPENDENT AUDITORS

Deloitte & Touche LLP
Suite 2300
333 Clay Street
Houston, TX 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 paid 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) 880-6812, 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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**www.epplp.com**

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