ENTERPRISE PRODUCTS PARTNERS L P
Form 8-K
December 06, 2004

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

# FORM 8-K

**CURRENT REPORT**

Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): September 30, 2004

## ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of registrant as specified in its charter)

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| **Delaware** | **1-14323** | **76-0568219** |
| (State or Other Jurisdiction of Incorporation or Organization) | (Commission File Number) | (I.R.S. Employer Identification No.) |

| | |
|---|---|
| **2727 North Loop West, Houston, Texas** | **77008-1044** |
| (Address of Principal Executive Offices) | (Zip Code) |

Registrant s Telephone Number, including Area Code: **(713) 880-6500**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

¨ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

¨ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

¨ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

¨ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

**Item 8.01. Other Events.**

As described in our quarterly report on Form 10-Q for the period ended September 30, 2004 (the September 30, 2004 10-Q ), Enterprise Products Partners L.P. ( Enterprise ) and GulfTerra Energy Partners, L.P. ( GulfTerra ) completed the merger of GulfTerra with a wholly-owned subsidiary of Enterprise. As a result of the merger, and as described in our September 30, 2004 10-Q, we have revised and renamed our reportable business segments to reflect the combined operations of the two companies. As an aid in comparability and for transition purposes, we are hereby updating portions of the historical description of our business and segment-related information as set forth in our annual report on Form 10-K for the year ended December 31, 2003 originally found under Items 1 and 2 ( Business and Properties ) and Item 7 ( Management s Discussion and Analysis of Financial Condition and Results of Operation or MD&A ) and Item 7A ( Quantitative and Qualitative Disclosures About Market Risk ). In addition, we are hereby updating our audited consolidated financial statements included under Item 8 ( Financial Statements and Supplementary Data ) to solely reflect the new business segments.

Please refer to our annual report on Form 10-K for the year ended December 31, 2003 for the definitions of capitalized terms not defined herein. We have presented the following sections of our 2003 annual report on Form 10-K solely to reflect our new business segment information as if our new business segment reporting structure had been in place on December 31, 2003. Except as required to reflect the effects of our new business segment information, these items have not been modified or updated for events subsequent to the filing of our annual report on Form 10-K for the year ended December 31, 2003. The following represents an index to the various sections of the material presented under Item 8.01 of this current report on Form 8-K:



In addition to presenting the foregoing information, we are including a supplemental schedule containing selected quarterly financial and operating information stated as if our new business segment reporting structure had been in place during 2003 and for the nine months ended September 30, 2004.

**SECTION 1 REVISED BUSINESS DESCRIPTION**
**Items 1 and 2. Business and Properties**

*General*

We are a leading North American midstream energy company providing a wide range of services to producers and consumers of natural gas and natural gas liquids, or NGLs. We were formed as a limited partnership in 1998 (NYSE symbol, EPD ) and conduct all of our business through our wholly-owned subsidiary, Enterprise Products Operating L.P. and its subsidiaries and joint ventures. Our General Partner, Enterprise Products GP, LLC, owns a 2% interest in us.

We do not have any employees. All of our management, administrative and operating functions are performed by employees of EPCO, our ultimate parent company, pursuant to the Administrative Services Agreement. For a discussion of the Administrative Services Agreement, please read Item 13 of this annual report. Unless the context requires otherwise, references to we, us, our, the Company or Enterprise are intended t mean the consolidated business and operations of Enterprise Products Partners L.P. Our principal executive offices are located at 2727 North Loop West, Houston, Texas 77008 and our telephone number is (713) 880-6500.

We provide a full range of services to customers and generate predominately fee-based net cash flow from multiple sources along our natural gas and NGL system of assets. NGLs are used by the petrochemical and refining industries to produce plastics, motor gasoline and other industrial and consumer products and also are used as residential and industrial fuels. Our midstream energy services include the:

- gathering and transmission of raw natural gas from both onshore and offshore Gulf of Mexico developments;
- processing of raw natural gas into a marketable product that meets industry quality specifications by removing mixed NGLs and impurities;
- purchase of natural gas for resale to our industrial, utility and municipal customers;
- transportation of mixed NGLs to fractionation facilities by pipeline;
- fractionation (or separation) of mixed NGLs produced as by-products of crude oil refining and natural gas production into component NGL products: ethane, propane, isobutane, normal butane and natural gasoline;
- transportation of NGL products to end-users by pipeline, railcar and truck;
- import and export of NGL products and petrochemical products through our dock facilities;
- fractionation of refinery-sourced propane/propylene mix into high-purity propylene, propane and mixed butane;
- transportation of high-purity propylene to end-users by pipeline;
- storage of natural gas, mixed NGLs, NGL products and petrochemical products;
- conversion of normal butane to isobutane through the process of isomerization;
- production of high-octane additives for motor gasoline from isobutane; and
- sale of NGLs and petrochemical products we produce and/or purchase for resale.

In addition to our strategic position in the Gulf of Mexico, we have access to major natural gas and NGL supply basins throughout the United States and Canada, including the Rocky Mountains, the San Juan and Permian basins, the Mid-Continent region and, through third-party pipeline connections, north into Canada s Western Sedimentary basin. Our asset platform in the Gulf Coast region of the United States, combined with our Mid-America and Seminole pipeline systems, create the only integrated natural gas and NGL transportation, fractionation, processing, storage and import/export network in North America.



*Business Strategy*

Our business strategy is to:

- capitalize on expected increases in natural gas and NGL production resulting from development activities in the Rocky Mountain, Permian Basin and Mid-Continent regions and the deepwater regions, continental shelf and onshore and coastal areas of the Gulf of Mexico;
- develop and invest in joint venture projects with strategic partners that will either provide the raw materials for these projects or purchase the ventures end products;
- share capital costs and risks associated with our operations through the formation of strategic alliances, joint ventures and similar arrangements with other businesses;
- expand our asset base through accretive acquisitions of complementary midstream energy assets, particularly those of fee-based businesses such as pipelines; and
- maintain a sound capital structure, which is important in managing our liquidity and capital resource requirements and providing us with the financial flexibility to fund future growth opportunities.

*Recent Events*

On December 15, 2003, we and certain of our affiliates, El Paso Corporation and certain of its affiliates ( El Paso ), and GulfTerra Energy Partners, L.P. ( GulfTerra ) and certain of its affiliates entered into a series of agreements under which GulfTerra would merge with one of our subsidiaries, with GulfTerra surviving the merger and becoming a wholly-owned subsidiary of the Company. Formed in 1993, GulfTerra is a publicly traded limited partnership (NYSE symbol, GTM ) that manages a balanced, diversified portfolio of interests and assets relating to the midstream energy sector. Prior to December 15, 2003, El Paso was the majority owner of GulfTerra s general partner and owns a 31.8% limited partner interest in GulfTerra. GulfTerra s principal executive offices are located at 4 East Greenway Plaza, Houston, Texas 77046 and its phone number is (832) 676-4853.

In general, GulfTerra s business lines include:

- Ownership or interests in over 15,700 miles of natural gas pipeline systems. These pipeline systems include gathering systems onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas and offshore in some of the most active drilling and development regions in the Gulf of Mexico. GulfTerra also owns interests in five natural gas processing and treating plants located in New Mexico, Texas and Colorado;
- Ownership in over 1,000 miles of intrastate NGL gathering and transportation pipelines and four NGL fractionation plants located in Texas. GulfTerra also owns interests in three offshore oil pipeline systems, which extend over 340 miles, owns a 3.3 MMBbl propane storage and leaching business located in Mississippi and owns or leases NGL storage facilities in Louisiana and Texas with aggregate capacity of approximately 21.3 MMBbls;
- Ownership in two salt dome natural gas storage facilities located in Mississippi that have a combined current working capacity of 13.5 Bcf. In addition, GulfTerra has the exclusive right to use a natural gas storage facility located in Wharton, Texas under an operating lease that expires in January 2008. This facility has a working gas capacity of 6.4 Bcf;
- Interests in seven multi-purpose offshore hub platforms in the Gulf of Mexico that were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities; and
- Interests in four oil and natural gas producing properties located in waters offshore Louisiana. Production is gathered, transported, and processed through GulfTerra s pipeline systems and platform facilities, and sold to various third parties and El Paso.

GulfTerra is one of the largest natural gas gatherers, based on miles of pipeline, in the prolific natural gas supply regions offshore in the Gulf of Mexico and onshore in Texas and in the San Juan Basin, which covers a significant portion of the four contiguous corners of Arizona, Colorado, New Mexico and Utah. These regions, especially the deepwater regions of the Gulf of Mexico, one of the United States fastest growing oil and natural gas producing regions, offer GulfTerra significant growth potential through the acquisition and construction of pipelines, platforms, processing and storage facilities and other energy infrastructure.

The proposed merger is a three-step process outlined as follows:

*Step One*. On December 15, 2003, we purchased a 50% membership interest in GulfTerra s general partner (GulfTerra Energy Company, L.L.C. or GulfTerra GP ) for $425 million. This investment is accounted for using the equity method. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which we refer to as Step Two and Step Three, do not occur.

*Step Two*. If all necessary regulatory and unitholder approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method and GulfTerra will be a consolidated subsidiary of our company. Step Two of the proposed merger includes the following transactions:

El Paso s contribution to our General Partner of El Paso s remaining 50% interest in GulfTerra GP for a 50% interest in our General Partner, and the subsequent capital contribution by our General Partner of such 50% interest in GulfTerra GP to us (without increasing our General Partner s interest in our earnings or cash distributions).

Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million; and

The exchange of each remaining GulfTerra common unit for 1.81 Enterprise common units, resulting in the issuance of approximately 103 million Enterprise common units to GulfTerra unitholders.

*Step Three*. Immediately after Step Two is completed, we expect to acquire nine cryogenic natural gas processing plants, one natural gas gathering system, one natural gas treating plant, and a small natural gas liquids connecting pipeline from El Paso for $150 million. We refer to the assets that we will acquire from El Paso as the South Texas midstream assets.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or grant is approximately $3.9 billion. For a period of three years following the closing of the proposed merger, El Paso will provide support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs of such services (excluding any overhead costs). 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 12 equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

We are working to complete the merger as soon as possible. A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both the Company and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions to the merger will be satisfied, we expect to complete the merger in the second half of 2004.

To review a copy of the merger agreement and related transaction documents, please read our Current Report on Form 8-K filed with the Securities and Exchange Commission on December 15, 2003.

*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as anticipate, project, expect, plan, goal, forecast, intend, could, believe, may and similar expressions and statements regarding our plans and o future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our General Partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please read our summarized *Risk Factors* below.

*Risk Factors*

Among the key risk factors that may have a direct impact on our results of operations and financial condition are:

**Risks Related to the Merger and the Related Transactions**

***We may not be able to successfully integrate our operations with GulfTerra s operations.***

Integration of the two previously independent companies will be a complex, time consuming and costly process. Failure to timely and successfully integrate these companies may have a material adverse effect on the combined company s business, financial condition and results of operations. The difficulties of combining the companies will present challenges to the combined company s management, including:

- operating a significantly larger combined company with operations in geographic areas and business lines in which we have not previously operated;
- managing relationships with new joint venture partners with whom we have not previously partnered;
- integrating personnel with diverse backgrounds and organizational cultures;
- experiencing potential operational interruptions or the loss of key employees, customers or suppliers;
- establishing the internal controls and procedures that the combined company will be required to maintain under the Sarbanes-Oxley Act of 2002; and
- consolidating other corporate and administrative functions.

The combined company will also be exposed to other risks that are commonly associated with transactions similar to the merger, such as unanticipated liabilities and costs, some of which may be material, and diversion of management s attention. As a result, the anticipated benefits of the merger may not be realized fully, if at all. We and GulfTerra could be required to divest significant assets to complete the merger.

***We and GulfTerra could be required to divest significant assets by regulatory authorities to complete the merger***

We cannot complete the merger until the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 has expired or terminated. Under the terms of the merger agreement, we are required to divest the assets we previously acquired from GulfTerra that are subject to an FTC consent decree (including our interests in the Manta Ray, Nautilus, Nemo and Stingray pipelines). GulfTerra is required to divest any assets required by the FTC to the extent such divestitures are recommended by us and we are required to divest any assets required by the FTC to the extent such divestitures, together with all required GulfTerra divestitures (but excluding the FTC consent decree assets), do not exceed $150 million. In addition, if such divestitures required by the FTC exceed $150 million, we and (with our consent) GulfTerra have the right to comply with such divestiture requirements to consummate the merger.

Divestitures of assets can be time consuming and may delay completion of the proposed merger. Because there may be a limited number of potential buyers for the assets subject to divestiture and because potential buyers will likely be aware of the circumstances of the sale, these assets could be sold at prices lower than their fair market value or the prices we or GulfTerra paid for these assets. These asset divestitures could also significantly reduce the value of the combined company, eliminate potential cost savings opportunities or lessen the anticipated benefits of the merger.

**Risks Related to the Combined Company s Leverage**

***The combined company s debt level may limit its future financial and operating flexibility.***

As of December 31, 2003, we had approximately $2.1 billion of consolidated debt. As of the same date, GulfTerra had approximately $1.8 billion of consolidated debt. As a result, the consolidated balance sheet of the combined company will have significant leverage. The amount of the combined company s debt could have several important effects on its future operations, including, among other things:

- a significant portion of the combined company s cash flow from operations will be dedicated to the payment of principal and interest on outstanding debt and will not be available for other purposes;
- the combined company s ability to pay distributions could be adversely affected;
- credit rating agencies may view the combined company s debt level negatively;
- covenants contained in our and GulfTerra s existing debt arrangements will require the combined company to continue to meet financial tests that may affect its flexibility in planning for and reacting to changes in its business;
- the combined company s ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- the combined company may be at a competitive disadvantage relative to similar companies that have less debt; and
- the combined company may be more vulnerable to adverse economic and industry conditions as a result of its significant debt level.

Our public debt indentures currently do not limit the amount of future indebtedness that we can create, incur, assume or guarantee. Our revolving credit facilities and the merger agreement, however, restrict our ability to incur additional debt, though any debt we may incur in compliance with these restrictions may still be substantial. Likewise, GulfTerra s public debt indentures, its revolving credit facility and the merger agreement restrict its ability to incur additional debt; however, any debt that it may incur in compliance with these restrictions may still be substantial. The incurrence of additional debt by GulfTerra or us could exacerbate any risks associated with the liquidity of the combined company.

Our and GulfTerra s revolving credit facilities and indentures for public debt contain conventional financial covenants and other restrictions. A breach of any of these restrictions by us or GulfTerra, as applicable, could permit the lenders to declare all amounts outstanding under those debt agreements to be immediately due and payable and, in the case of the credit facilities, to terminate all commitments to extend further credit.

The combined company s ability to access the capital markets to raise capital on favorable terms may be affected by the combined company s debt level, the amount of its debt maturing in the next several years and current maturities, and by adverse market conditions resulting from, among other things, general economic conditions, contingencies and uncertainties that are difficult to predict and impossible to control. If the combined company is unable to access the capital markets on favorable terms in the future, it might be forced to seek extensions for some of its short-term securities or to refinance some of its debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which the combined company might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that the combined company s leverage may adversely affect its future financial and operating flexibility and its ability to pay cash distributions at expected rates.

***The closing of the merger will trigger a repurchase obligation with respect to GulfTerra s outstanding senior notes and senior subordinated notes.***

The closing of the merger will constitute a change of control under GulfTerra s indentures for its senior notes and senior subordinated notes. As a result, GulfTerra will be obligated to offer to purchase each holder s notes at 101% of their principal amount, plus accrued interest. GulfTerra will also be obligated to offer to purchase each holder s senior notes at 101% of their principal amount, plus accrued interest, unless, among other things, the change of control (1) does not result in a ratings downgrade of the GulfTerra senior notes by either Moody s Investors Service or Standard & Poor s no later than 30 days after the change of control has occurred and (2) less than $250 million in aggregate principal amount of the GulfTerra senior subordinated notes are repurchased in response to the same change of control. GulfTerra currently has $250 million aggregate principal amount of senior notes outstanding and $886 million aggregate principal amount of senior subordinated notes outstanding.

In connection with completion of the merger, GulfTerra or the combined company will need to make an offer to repurchase these notes, or GulfTerra may seek to amend the indentures to waive the repurchase obligation or otherwise refinance its senior and senior subordinated notes. If GulfTerra or the combined company makes an offer to repurchase the notes, it is possible that holders of a large amount of GulfTerra s notes may exercise their repurchase right, in which case the combined company would be required to raise significant funds in the short term to fulfill GulfTerra s repurchase obligations. If GulfTerra were unable to meet its repurchase obligations, it would result in an event of default under GulfTerra s indentures, which would trigger an event of default under GulfTerra s revolving credit facility and senior secured term loan facility.

***Increases in interest rates could adversely affect the combined company s business.***

In addition to the combined company s exposure to commodity prices, the combined company will have significant exposure to increases in interest rates. As of December 31, 2003, we had approximately $2.1 billion of consolidated debt, of which $1.7 billion was at a fixed interest rate and $410 million was at a variable interest rate. Since January 1, 2004, we have entered into interest rate swap transactions that have effectively converted $250 million of our variable interest rate debt to fixed interest rate debt. For additional information regarding our interest rate hedging activities, please read Item 7A of this annual report on Form 10-K. Our merger with GulfTerra will result in a significant increase in our consolidated debt, some of which will be at variable interest rates. As a result, the combined company s results of operations, and its cash flows, could be materially adversely affected by significant increases in interest rates.

**Risks Related to the Combined Company s Business**

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

The combined company will operate predominantly in the midstream energy sector, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, the combined company s results of operations, cash flows and financial position may be adversely affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. In general terms, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are impossible to control. These factors include:

- the level of domestic production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and natural gas producing nations;
- the availability of transportation systems with adequate capacity;
- the availability of competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and NGLs; and
- conservation and the extent of governmental regulation of production and the overall economic environment.

The profitability of the combined company s NGL and natural gas processing operations will depend upon the difference between NGL product prices and natural gas prices. A reduction in the difference between NGL product prices and natural gas prices may result in reduced demand for fractionation, processing, NGL storage and NGL transportation services and, thus, may adversely affect the combined company s results of operations and cash flows from these activities. In addition, the combined company s natural gas processing activities will be exposed to commodity price risk associated with the relative price of NGLs to natural gas under its keepwhole natural gas processing contracts and, within defined limits, under its margin-band natural gas processing contract with Shell. Under these types of agreements, the combined company will take title to NGLs that it extracts from the natural gas stream and will be obligated to pay market value, based on natural gas prices, for the energy extracted from the natural gas stream. When prices for natural gas increase, the cost to the combined company of making these keepwhole payments will increase, and, where NGL prices do not experience a commensurate increase, the combined company will realize lower margins from these transactions. As a result, changes in prices for natural gas compared to NGLs could have an adverse affect on the results of operations, cash flows and financial position of the combined company.

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

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

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

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

Exploration and development of new oil and natural gas reserves is capital intensive, particularly offshore in the Gulf of Mexico. Many economic and business factors are out of the combined company s control and can adversely affect the decision by producers to explore for and develop new reserves. These factors include relatively low oil and natural gas prices, cost and availability of equipment, regulatory changes, capital budget limitations or the lack of available capital. For example, a sustained decline in the price of natural gas and crude oil could result in a decrease in natural gas and crude oil exploration and development activities in the regions where the combined company s facilities are located. This could result in a decrease in volumes to the combined company s offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators which would have an adverse affect on the combined company s results from operations, cash flows and financial position. Additional reserves, if discovered, may not be developed in the near future or at all.

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

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

*Ethane*. A reduction in the demand for ethylene may reduce demand for ethane. Also, if natural gas prices increase significantly in relation to ethane prices, it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale.

*Propane*. The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that the combined company transports.

*Isobutane*. Any reduction in demand for motor gasoline additives may reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, the combined company s operating margin from selling isobutane could be reduced.

*Propylene*. Any downturn in the domestic or international economy could cause reduced demand for propylene, which could cause a reduction in the volumes of propylene that the combined company produces and expose the combined company s investment in inventories of propane/propylene mix to pricing risk due to requirements for short-term price discounts in the spot or short-term propylene markets.

***The combined company will face competition from third parties in its midstream businesses.***

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

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

***The combined company s growth strategy may adversely affect its results of operations if it does not successfully integrate the businesses that it acquires or if the combined company substantially increases its indebtedness and contingent liabilities to make acquisitions.***

The combined company s ability to successfully execute its growth strategy is partially dependent upon making accretive acquisitions. As a result, from time to time, the combined company may evaluate and acquire assets and businesses that it believes complement its existing operations. Similar to the risks associated with integrating our operations with GulfTerra s operations, the combined company may be unable to integrate successfully businesses it acquires in the future. The combined company may incur substantial expenses or encounter delays or other problems in connection with its growth strategy that could negatively impact its results of operations. Moreover, acquisitions and business expansions involve numerous risks, including:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;
- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and
- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, depletion and amortization expenses. As a result, the combined company s capitalization and results of operations may change significantly following an acquisition. A substantial increase in the combined company s indebtedness and contingent liabilities could have a material adverse effect on its business.

***The combined company s capital projects may not result in an immediate increase in operating cash flows.***

GulfTerra is engaged in several capital expansion projects and greenfield projects for which significant capital has been expended, and the combined company s operating cash flow from a particular project may not increase immediately following its completion. For instance, if the combined company builds a new pipeline or platform or expands an existing facility, the design, construction, development and installation may occur over an extended period of time and the combined company may not receive any material increase in operating cash flow from that project until after it is placed in service. If the combined company experiences unanticipated or extended delays in generating operating cash flow from these projects, then it may need to reduce or reprioritize its capital budget, sell non-core assets, access the capital markets or decrease distributions to unitholders to meet its capital requirements.

***The combined company s actual construction, development and acquisition costs could exceed forecasted amounts.***

The combined company may have significant expenditures for the development, construction or other acquisition of energy infrastructure assets, including some construction and development projects with significant technological challenges. For example, underwater operations, especially those in water depths in excess of 600 feet, are very costly and involve much more uncertainty and risk, and if a problem occurs, the solution, if one exists, may be very costly and time consuming. Accordingly, there is an increase in the frequency and amount of cost overruns related to underwater operations, especially in depths in excess of 600 feet. The combined company may not be able to complete its projects, whether in deep water or otherwise, at the costs currently estimated.

***The combined company may not be able to fully execute its growth strategy if it encounters illiquid capital markets or increased competition for qualified assets.***

The strategy of the combined company includes growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance the combined company s ability to compete effectively and diversify its asset portfolio, thereby providing more stable cash flow. Both companies regularly consider and enter into discussions regarding, and are currently contemplating, potential joint ventures, stand-alone projects or other transactions that they believe will present opportunities to realize synergies, expand their respective roles in the energy infrastructure business and increase their respective market positions.

The combined company may need new capital to finance the future development and acquisition of assets and businesses. Limitations on the combined company s access to capital may impair its ability to execute this strategy. Costly capital may limit the combined company s ability to develop or acquire accretive assets. This strategy may require substantial capital, and the combined company may not be able to raise the necessary funds on satisfactory terms, if at all.

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

***An impairment of goodwill could reduce the combined company s earnings.***

We have recorded $82.4 million of goodwill on our consolidated balance sheet as of December 31, 2003. Based upon our preliminary analysis, we anticipate recording approximately $2 billion of goodwill upon completion of the merger, but that estimate is subject to change. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles will require the combined company to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If the combined company were to determine that any of its remaining balance of goodwill was impaired, it would be required to take an immediate charge to earnings with a correlative effect on unitholders equity.

***The use of derivative financial instruments could result in financial losses to the combined company.***

We and GulfTerra historically have sought to limit a portion of the adverse effects resulting from changes in oil and natural gas commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent that the combined company hedges its commodity price and interest rate exposures, it will forego the benefits it would otherwise experience if commodity prices or interest rates were to change in its favor. In addition, even though monitored by management, hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging policies and procedures are not followed.

***The combined company will be unable to cause its joint ventures to take or not to take certain actions unless some or all of its joint venture participants agree.***

We and GulfTerra participate in several substantial joint ventures, and that participation will continue after the merger. Due to the nature of joint ventures, each participant in each of these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant organizational documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features include a corporate governance structure that requires at least a majority in interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, the combined company may be unable to cause any of its joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the particular joint venture or the combined company.

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

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

***The interruption of distributions to the combined company from its subsidiaries and joint ventures may affect the combined company s ability to satisfy its obligations and to make cash distributions to its unitholders.***

Like us and GulfTerra, the combined company will be a holding company with no business operations. The only significant asset of the combined company will be the equity interests it owns in its subsidiaries and joint ventures. As a result, the combined company will depend upon the earnings and cash flow of its subsidiaries and joint ventures and the distribution of that cash to the combined company in order to meet the combined company s obligations and to allow it to make distributions to its unitholders.

GulfTerra is party to senior and senior subordinated note indentures under which approximately $1.1 billion in principal amount of debt securities was outstanding as of December 31, 2003. These indentures restrict

GulfTerra s and its subsidiaries ability to make cash distributions. If GulfTerra and the combined company are not able to effect amendments to these indentures or refinance the senior and senior subordinated notes, then these restrictions could significantly limit GulfTerra s ability to distribute cash to us after the merger.

***A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail the combined company s operations and otherwise adversely affect its cash flow.***

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

If one or more facilities that are owned by the combined company or that deliver oil, natural gas or other products to the combined company are damaged by severe weather or any other disaster, accident, catastrophe or event, the combined company s operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply the combined company s facilities or other stoppages arising from factors beyond its control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that the combined company will be a party to will obligate it to indemnify its customers for any damage or injury occurring during the period in which the customers natural gas is in its possession. Any event that interrupts the fees generated by the combined company s energy infrastructure assets, or which causes it to make significant expenditures not covered by insurance, could reduce the combined company s cash available for paying its interest obligations as well as unitholder distributions and, accordingly, adversely affect the market price of the combined company s securities.

We expect that the combined company will maintain adequate insurance coverages, although it will not cover many types of interruptions that might occur. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, the combined company may not be able to renew its existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. In particular, we have been informed by our insurance carrier that upon renewal of our policy in April 2004, MTBE related claims may be excluded from the scope of our insurance coverage. See *Regulation and Environmental Matters Impact of Clean Air Act s oxygenated fuels programs on our BEF investment*, beginning on page 42 of this annual report. If the combined company were to incur a significant liability for which it was not fully insured, it could have a material adverse effect on the combined company s financial position. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

***Terrorist attacks aimed at the combined company s facilities could adversely affect its business.***

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

**Risks Related to Our Common Units as a Result of Our Partnership Structure**

***We may issue additional securities without the approval of our common unitholders.***

Following the merger and subject to NYSE rules, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve its issuance of equity securities ranking equal or junior to the common units. The issuance of additional common units or other equity securities of equal rank will have the following effects:

- the proportionate ownership interest of a common unit will decrease;
- the amount of cash available for distributions on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

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

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

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

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

***We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.***

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

***Cost reimbursements due our general partner may be substantial and will reduce our cash available for distribution to holders of our units.***

Prior to making any distribution on our units, we will reimburse our general partner and its affiliates, including officers and directors of our general partner, for expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to pay cash distributions to holders of our units. Our general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide other services to us for which we will be charged fees as determined by our general partner.

***Our general partner and its affiliates have limited fiduciary responsibilities and conflicts of interest with respect to our partnership.***

The directors and officers of our general partner and its affiliates have duties to manage the general partner in a manner that is beneficial to the general partner s members. At the same time, our general partner has duties to manage our partnership in a manner that is beneficial to us. Therefore, our general partner s duties to us may conflict with the duties of its officers and directors to the general partner s members. Such conflicts may include, among others, the following:

- decisions of our general partner regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and the general partner;
- under our partnership agreement, our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our general partner is allowed to take into account the interests of parties other than us, such as our parent company, EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to unitholders;
- affiliates of our general partner may compete with us in certain circumstances;
- our general partner may limit our liability and reduce our fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law; and
- we do not have any employees and we rely solely on employees of EPCO and its affiliates.

***Even if unitholders are dissatisfied, they cannot easily remove our general partner.***

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders did not elect our general partner or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Our general partner may not be removed except upon the vote of the holders of at least 66.7% of our outstanding units voting together as a single class. Because affiliates of our general partner own more than one-third of our outstanding units, our general partner currently cannot be removed without the consent of our general partner and its affiliates.

Unitholders voting rights are further restricted by our partnership agreement provision stating that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders ability to influence the manner or direction of our management.

As a result of these provisions, the price at which our common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

***Our common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.***

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business.

Under Delaware law, our general partner generally has unlimited liability for the obligations of our partnership, such as our debts and environmental liabilities, except for those contractual obligations of our partnership that are expressly made without recourse to our general partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a limited partner may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

***A large number of our outstanding common units may be sold in the market, which may depress the market price of our common units.***

Sales of a substantial number of our common units in the public market could cause the market price of our common units to decline. Immediately after the merger occurs, we currently estimate a total of approximately 320 million of our common units (including those which may be issued upon unitholder approval and the conversion of the 4,413,549 of our Class B special units) will be outstanding. Shell owns 41,000,000 of our common units, representing approximately 19.1% of our outstanding common units at February 20, 2004, has publicly announced its intention to reduce its holdings of our common units on an orderly schedule over a period of years, taking into account market conditions. Under a registration rights agreement, we are obligated, subject to certain limitations and conditions, to register the common units held by Shell for resale. Sales of a substantial number of these common units in the trading markets, whether in a single transaction or series of transactions, or the possibility that these sales may occur, could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell its common units in the future.

**Tax Risks Related to the Merger and to Owning Our Common Units**

***No ruling has been obtained with respect to the tax consequences of the merger.***

While it is anticipated that no gain or loss will be recognized by our unitholders as a result of the merger (except with respect to a net decrease in a unitholder s share of nonrecourse liabilities discussed below), no ruling has been or will be requested from the Internal Revenue Service, or IRS, with respect to the tax consequences of the merger. Instead, we are relying on the opinions of our counsel as to the tax consequences of the merger, and counsel s conclusions may not be sustained if challenged by the IRS.

***The merger may result in income recognition by our unitholders.***

As a result of the merger, our common unitholder s share of nonrecourse liabilities will be recalculated. Each of our unitholders will be treated as receiving a deemed cash distribution equal to the excess, if any, of such unitholder s share of nonrecourse liabilities immediately before the merger and such unitholder s share of nonrecourse liabilities immediately following the merger. If the amount of the deemed cash distribution received by a common unitholder exceeds the unitholder s basis in its partnership interest, such unitholder will recognize gain in an amount equal to such excess. The application of the rules governing the allocation of nonrecourse liabilities in the context of the merger is complex and subject to uncertainty. While we have agreed to apply these rules, to the extent permissible, in a manner that minimizes the amount of any net decrease in the amount of debt allocable to our unitholders, there can be no assurance that there will not be a net decrease in the amount of nonrecourse liabilities allocable to our common unitholder as a result of the merger.

***The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to common unitholders following the merger.***

The anticipated after-tax economic benefit of owning our common units depends largely on us being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting our partnership.

If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and we likely would pay state taxes as well. Distributions to you would generally be taxed again to you as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, the cash available for distribution to you would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the after-tax return to you, likely causing a substantial reduction in the value of our common units.

A change in current law or a change in our business could cause us to be taxed as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect that impact on us.

***A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contests will be borne by our unitholders and our general partner.***

We have not requested a ruling from the IRS with respect to any matter affecting our partnership. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not concur with our counsel s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne indirectly by our unitholders and our general partner.

***Our common unitholders may be required to pay taxes even if they do not receive any cash distributions.***

Our common unitholders are required to pay federal income taxes and, in some cases, state, local and foreign income taxes on their share of our taxable income even if they do not receive any cash distributions from us. They may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

***Tax gain or loss on disposition of our common units could be different than expected.***

If you sell our common units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you. Should the IRS successfully contest some positions we take, you could recognize more gain on the sale of your units than would be the case under those positions without the benefit of decreased income in prior years. Also, if you sell units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

***Tax-exempt entities, regulated investment companies and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.***

Ownership of common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), regulated investment companies (known as mutual funds) and foreign persons raises issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Very little of our income will be qualifying income to a regulated investment company or mutual fund. Distributions to foreign persons will be reduced by withholding taxes at the highest effective U.S. federal income tax rate for individuals, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

***We are registered as a tax shelter, which may increase the risk of an IRS audit of us or a unitholder.***

We are registered with the IRS as a tax shelter. Our tax shelter registration number is 990610007. The tax laws require that some types of entities, including some partnerships, register as tax shelters in response to the perception that they claim tax benefits that may be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in our unitholders tax returns and may lead to audits of our unitholders tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return and indirectly bear a portion of the cost of an audit of us.

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

Because we cannot match transferors and transferees of our common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of our common units and could have a negative impact on the value of our common units or result in audit adjustments to our common unitholder s tax returns.

***Our common unitholders will likely be subject to state and local taxes in states where they do not live as a result of an investment in our common units.***

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property and in which they do not reside. Our common unitholders may be required to file state and local income tax returns and pay state and local income taxes in many or all of the jurisdictions in which we do business or own property. Further, our common unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of the unitholder to file all United States federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of ownership of our common units.

**The Company s Operations**

As a result of our merger with GulfTerra, we have four reportable segments: Offshore Pipelines & Services, Onshore Natural Gas Pipelines & Services, NGL Pipelines & Services, and Petrochemical Services. Our new business segments are generally organized and managed according to the type of services rendered (or technology or process employed) and products produced and/or sold, as applicable.

**Offshore Pipelines & Services**

At December 31, 2003, our Offshore Pipelines & Services business segment consisted of equity interests in companies that own 739 miles of natural gas pipelines located offshore Louisiana in the Gulf of Mexico.

Our offshore natural gas pipeline systems provide for the gathering and transmission of natural gas from offshore Louisiana natural gas production developments. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas at other points throughout the system. Generally, natural gas pipeline transportation agreements generate revenue for these systems based on a transportation fee per unit of volume (generally in MMBtus) transported. In general, the Gulf of Mexico systems in which we own an equity interest do not take title to the natural gas volumes that they transport; rather, the shipper retains title and the associated commodity price risk.

Our Gulf of Mexico offshore pipelines compete with other offshore systems primarily on the basis of transportation rates and service and are strategically situated to gather a substantial volume of natural gas production in the offshore Louisiana area from both continental shelf and deepwater developments. These systems exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Our offshore systems are affected by natural gas exploration and production activities. If these exploration and production activities decline due to (i) the inability of producers to find economically viable reserves; (ii) a weakened domestic economy which lowers natural gas demand; or (iii) natural depletion of the oil and gas fields to which they are connected, then throughput volumes on these pipelines will decline, thereby affecting our earnings from these assets. We actively seek to offset the loss of volumes due to natural depletion by adding connections to new customers and fields.

The following table summarizes our offshore natural gas pipeline transportation and distribution networks at December 31, 2003. Our ownership interest in each pipeline is held indirectly through a company in which we have an investment accounted for under the equity method.

| Offshore Natural Gas Pipelines | Length in Miles | Our Ownership Interest at December 31, 2003 |
|---|---|---|
| Stingray | 379 | 50.0% |
| Manta Ray | 235 | 25.7% |
| Nautilus | 101 | 25.7% |
| Nemo | 24 | 33.9% |
| Total offshore natural gas pipelines | 739 | |

*Stingray*. The Stingray pipeline is a 379-mile, regulated natural gas pipeline system that transports natural gas and condensate from certain production areas located in the Gulf of Mexico offshore Louisiana to onshore transmission systems located in south Louisiana. This system includes a natural gas dehydration facility connected to the onshore terminus of the pipeline in south Louisiana. Shell is the operator of this pipeline and related dehydration facility.

*Manta Ray*. The Manta Ray system comprises approximately 235 miles of unregulated natural gas pipelines and related equipment located in the Gulf of Mexico offshore Louisiana. The primary sources of throughput for the Manta Ray system are the Green Canyon, Ship Shoal, South Timbalier, Grand Isle and Ewing Bank areas of the Gulf of Mexico offshore Louisiana. We expect that natural depletion of these fields will be partially offset by the addition of volumes from the Southern Green Canyon development, which is forecast to begin production in late 2004. Shell operates this system.

*Nautilus*. The Nautilus system comprises 101 miles of regulated pipelines located in the Gulf of Mexico offshore Louisiana. Currently, the primary source of natural gas throughput for the Nautilus system is production from the Manta Ray system through its interconnection in the Ship Shoal 207 area of the Gulf of Mexico offshore Louisiana. Shell is the administrative agent and Marathon the operator for this system.

*Nemo*. The Nemo pipeline is a 24-mile pipeline that transports natural gas volumes from Shell s Green Canyon development to an interconnect with Manta Ray. Shell operates this system.

*Offshore natural gas pipeline utilization*

The maximum amount of natural gas that these systems can transport per day depends upon the operating balance achieved at a given time between various segments of each system. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacity of a system cannot be practically determined. In light of the complex, interconnected nature of the pipeline networks and the varying diameter of pipe used and pressure employed, the utilization rates of our principal offshore natural gas pipeline systems are measured in BBtus per day of natural gas transported. As shown in the following table, the utilization rates of our principal offshore natural gas pipelines are measured in terms of throughput (in BBtus per day, on a net basis).

| | **For Year Ended December 31,** | | |
|---|---|---|---|
| | **2003** | **2002** | **2001** |
| Stingray | 228 | 265 | 300 |
| Manta Ray, Nautilus and Nemo | 205 | 235 | 266 |
| Total net volume of natural gas pipelines | 433 | 500 | 566 |

**Onshore Natural Gas Pipelines & Services**

At December 31, 2003, our Onshore Natural Gas Pipelines & Services business segment primarily consisted of 1,042 miles of natural gas pipelines that we either own or have an equity interest in.

Our onshore natural gas pipeline systems provide for the gathering, transmission and storage of natural gas from offshore and onshore Louisiana developments. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas at other points throughout the system. Generally, natural gas pipeline transportation agreements generate revenue for these systems based on a transportation fee per unit of volume (generally in MMBtus) transported. Natural gas pipelines (such as our Acadian Gas System) may also gather and purchase natural gas from producers and suppliers and resell such natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers. Our Acadian Gas subsidiary is exposed to commodity price risk to the extent it takes title to natural gas volumes through certain of its contracts.

Within their market area, our onshore systems compete with other natural gas pipeline companies on the basis of price (in terms of transportation rates and/or natural gas selling prices), service and flexibility. Our competitive position within the onshore market is positively affected by our longstanding relationships with customers and the limited number of delivery pipelines connected (or capable of being connected) to the customers we serve.

Our onshore Louisiana pipelines have historically experienced slightly higher throughput rates during the winter and summer months. During the winter, natural gas consumption by residential and industrial users for heating is greater due to the decline in temperatures. During the summer, natural gas consumption by gas-fired electrical generation facilities is greater due to an increase in air conditioning demand.

Our onshore systems are affected by natural gas exploration and production activities. If these exploration and production activities decline due to (i) the inability of producers to find economically viable reserves; (ii) a weakened domestic economy which lowers natural gas demand; or (iii) natural depletion of the oil and gas fields to which they are connected, then throughput volumes on these pipelines will decline, thereby affecting our earnings from these assets. We actively seek to offset the loss of volumes due to natural depletion by adding connections to new customers and fields.

The following table summarizes our onshore natural gas pipeline transportation and distribution networks at December 31, 2003. Our ownership interest in each pipeline is held directly through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method.

| **Onshore Natural Gas Pipelines** | **Length in Miles** | **Our Ownership Interest at December 31, 2003** |
|---|---|---|
| Acadian Gas System: | | |
| Cypress | 577 | 100.0% |
| Acadian | 438 | 100.0% |
| Evangeline | 27 | 49.5% |
| Total Acadian Gas System | 1,042 | |

*Acadian Gas System*. The Acadian Gas System is a 1,042-mile pipeline system consisting of three natural gas pipelines that we operate: the 577-mile Cypress pipeline, 438-mile Acadian pipeline, and the 27-mile Evangeline pipeline. This system is involved in the purchase, sale, transportation and storage of natural gas in Louisiana. We also lease a natural gas storage facility with approximately 3 Bcf of capacity that is an integral part of this system.

The Acadian Gas System links supplies of natural gas from Gulf of Mexico production (through connections with offshore pipelines) and various onshore developments to industrial, electric and local gas distribution customers primarily located in Louisiana. In addition, this system has interconnects with twelve interstate and four intrastate pipeline companies and a bi-directional interconnect with the U.S. natural gas marketplace at the Henry Hub. In general, the natural gas transported by the Acadian Gas System originates from onshore Louisiana sources and offshore Gulf of Mexico production areas.

*Natural gas pipeline utilization*

The exact capacity of a system cannot be practically determined due to the same limitations and complicating factors discussed above within the *Offshore natural gas pipeline utilization* section of this *Item 1 and 2. Business and Properties* section. As shown in the following table, the utilization rates of our onshore natural gas pipelines are measured in terms of throughput (in BBtus per day, on a net basis).

| | **For Year Ended December 31,** | | |
|---|---|---|---|
| | **2003** | **2002** | **2001** |
| Acadian Gas System | 599 | 701 | 783 |

**NGL Pipelines & Services**

At December 31, 2003, our NGL Pipelines & Services business segment is comprised of (i) our natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating an approximate 11,644 miles and related storage facilities, and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our NGL import and export terminaling operations.

*Natural Gas Processing and related NGL marketing activities*

At the core of our natural gas processing business are twelve processing plants located on the Louisiana and Mississippi Gulf Coast with a total natural gas processing capacity of 11.56 Bcf/d. The following table lists our natural gas processing plants, gross and net processing capacities and our ownership interest in each facility at December 31, 2003.

| Natural Gas Processing Facility | Location | Total Plant Gas Processing Capacity (Bcf/d) | Our Ownership Interest at December 31, 2003 (1) | Net Gas Processing Capacity (Bcf/d) (2) |
|---|---|---|---|---|
| Yscloskey | Louisiana | 1.85 | 30.4% | 0.56 |
| Toca | Louisiana | 1.10 | 59.9% | 0.51 |
| Venice | Louisiana | 1.30 | 13.1% | 0.48 |
| North Terrebonne | Louisiana | 1.30 | 31.3% | 0.41 |
| Pascagoula | Mississippi | 1.00 | 40.0% | 0.40 |
| Calumet | Louisiana | 1.60 | 32.4% | 0.33 |
| Neptune | Louisiana | 0.30 | 66.0% | 0.20 |
| Sea Robin | Louisiana | 0.90 | 15.5% | 0.21 |
| Burns Point | Louisiana | 0.16 | 50.0% | 0.08 |
| Blue Water | Louisiana | 0.95 | 7.4% | 0.06 |
| Iowa | Louisiana | 0.50 | 2.0% | 0.01 |
| Patterson II | Louisiana | 0.60 | 1.9% | 0.01 |
| | Total | 11.56 | | 3.26 |

(1) We own direct consolidated interests in these facilities with the exception of Venice, which is part of our investment in VESCO.
(2) Net gas processing capacity does not necessarily correspond to our ownership interest. It is based on a variety of factors including volumes processed at facility, ownership interest, contractual arrangements and other factors.

Our natural gas processing facilities are primarily straddle plants situated on mainline natural gas pipelines that bring unprocessed natural gas production from the Gulf of Mexico onshore. These facilities allow us to extract NGLs from a raw natural gas stream which enable the natural gas to meet pipeline quality specifications. After extraction, we typically transport the mixed NGLs to a centralized facility for fractionation into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets.

In general, we provide natural gas processing services under three types of arrangements: margin-band/keepwhole contracts, percent-of-liquids contracts and fee-based contracts. The key features of each type of contract are described below:

*Margin-band/keepwhole contracts*. Under this type of agreement, we take ownership of mixed NGLs extracted from a producer s natural gas stream. In return, we pay the producer for the energy value of the mixed NGLs we extract from the natural gas stream and that of the fuel consumed by our plant in the extraction process. Collectively, these energy values are referred to as plant thermal reduction ( PTR ).

The payment we make to a producer for PTR is generally based on the price of natural gas multiplied by the quantity of PTR extracted or used. We derive a profit from these arrangements to the extent that revenues from our sale and delivery of the mixed NGLs we extracted exceed the sum of the PTR costs (which are generally limited, see CAONO below) paid to the producer, our plant operating costs and any other costs such as fractionation and pipeline fees that we might incur.

The most significant contract affecting our natural gas processing business is the Shell agreement, which is a margin band, or modified keepwhole arrangement which grants us the right to process Shell s current and future production within state and federal waters of the Gulf of Mexico. The Shell processing agreement includes a life of lease dedication, which may extend the agreement well beyond its initial 20-year term ending in 2019. This contract was amended effective March 1, 2003. In general, the amended contract includes the following rights and obligations:

- the exclusive right, but not the obligation in all cases, to process substantially all of Shell s Gulf of Mexico natural gas production; plus
- the exclusive right, but not the obligation in all cases, to process all natural gas production from leases dedicated by Shell for the life of such leases; plus
- the right to all title, interest and ownership in the mixed NGLs extracted by our gas processing plants from Shell s natural gas production from such leases; with
- the obligation to re-deliver to Shell the natural gas stream after any mixed NGLs are extracted.

The amended contract contains a mechanism (termed Consideration Adjustment Outside of Normal Operations or CAONO ) to adjust the value of the PTR we reimburse to Shell. The CAONO, in effect, protects us from processing Shell s natural gas at an economic loss when the value of the mixed NGLs we extract is less than the sum of the cost of the PTR reimbursement, operating costs of the gas processing facility and other costs such as NGL fractionation and pipeline fees.

Approximately 50% of the natural gas volumes we currently process are covered by the margin-band arrangement that we have with Shell. During 2003, we reduced our use of traditional keepwhole arrangements from approximately 70% to less than 5%, which excludes the 50% we process under Shell s margin-band arrangement. Prior to its amendment in March 2003, the Shell contract was a traditional keepwhole arrangement.

*Percent-of-liquids contracts.* Under this type of agreement, we take ownership of a percentage of mixed NGLs extracted from a producer s natural gas stream. The producer retains title to the remaining percentage of mixed NGLs extracted and is responsible for the cost of PTR with respect to 100% of the mixed NGLs extracted. We derive a profit from percent-of-liquids arrangements to the extent that revenues from our sale and delivery of the mixed NGLs we extracted exceed the sum of our plant operating costs and any other costs such as fractionation and pipeline fees that we might incur.

As of December 31, 2003, approximately 40% of the natural gas volumes we process are done so under percent-of-liquids contracts. During 2003, we increased the volume of natural gas processed under these arrangements from approximately 30% to 40% in an effort to reduce our use of traditional keepwhole arrangements.

*Fee-based contracts*. Under this type of agreement, we earn a fee based on the volume of natural gas we process. The producer retains title to any mixed NGLs extracted and is responsible for all PTR costs. We derive a profit from fee-based arrangements to the extent that the fees we earn are greater than our plant operating costs.

As of December 31, 2003, approximately 15% of the natural gas volumes we process are done so under fee-based contracts. During 2003, we increased the volume of natural gas processed under these arrangements from less than 5% to approximately 15% in an effort to reduce our use of traditional keepwhole contracts.

In general, keepwhole and percent-of-liquids contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs we would take ownership of. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

Due to the increase in natural gas prices relative to NGL prices in recent years, there is an industry trend that new gas processing contracts on the U.S. Gulf Coast are being structured as either percent-of-liquids arrangements, fee-based arrangements or hybrid arrangements. A hybrid arrangement typically calls for the processor to provide processing services under a percent-of-liquids arrangement with the producer having the processing election. If the producer elects to not process under the percent-of-liquids arrangement, the processor has the option to process the gas under a keepwhole arrangement. If the processor elects to not exercise its option to process under a keepwhole arrangement, the gas is processed under a fee-based arrangement. We believe that providing natural gas processing services under these types of arrangements significantly reduces the risk and inherent fluctuation in our gross operating margin from natural gas processing caused by changes in natural gas and NGL prices.

The following table shows our net natural gas processing volumes and the corresponding overall utilization rates of our net natural gas processing capacity for each of the last three years. The table also shows our equity NGL production for each of the last three years. Equity NGL production is defined as the volume of mixed NGLs extracted by the gas plants to which we take title under the terms of processing agreements or as a result of plant ownership interests.

| | **For Year Ended December 31,** | | |
|---|---|---|---|
| | **2003** | **2002** | **2001** |
| Net natural gas processing volume (Bcf/d) | 2.06 | 2.15 | 2.28 |
| Net natural gas processing capacity (Bcf/d) | 3.26 | 3.37 | 3.25 |
| Utilization rate | 63% | 64% | 70% |
| Equity NGL production (MBPD) (1) | 56 | 73 | 63 |

(1) Equity NGL production rates for 2003 and 2001 were adversely affected by high natural gas prices relative to the value of NGLs extracted. For additional information regarding natural gas and NGL prices, please review the *Product and Commodity Price Information* table in *Management s Discussion and Analysis of Financial Condition and Results of Operations - Our Results of Operations* on page 51 of this current report.

As noted previously, under certain processing arrangements, we take title to a portion of the mixed NGLs that are extracted by our natural gas processing plants. Once this mixed NGL volume is fractionated into purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline), we use them to meet contractual requirements or sell them on spot and forward markets as part of our NGL marketing activities. As part of these marketing activities, we have a number of isobutane sales contracts. To fulfill our obligations under these sales contracts, we can purchase isobutane on the open market for resale, sell isobutane from our inventory or pay our isomerization business (which is part of the Petrochemical Services segment) a toll processing fee to process our inventories of imported or domestically-sourced normal and mixed butanes into isobutane. The intersegment expense and revenue recorded as a result of utilizing the services of our isomerization business are eliminated in consolidation.

In support of its commercial goals, our NGL marketing activities within this segment rely on inventories of mixed NGLs and purity NGL products. These inventories are the result of accumulated equity NGL production volumes, imports and other spot and contract purchases. Our inventories of ethane, propane and normal butane are typically higher in summer months as each are in higher demand and at higher price levels during winter months. Isobutane and natural gasoline inventories are generally stable throughout the year. Our inventory cycle begins in late-February to mid-March (the seasonal low point); builds through September; remains level until early December; before being drawn down through winter until the seasonal low is reached again.

To the extent that we are obligated under our margin-band/keepwhole gas processing contracts to pay market value for or replace the PTR extracted from the natural gas stream, we are exposed to various risks, primarily that of commodity price fluctuations. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity financial instruments.

Some of our exposure to commodity price risk is mitigated because natural gas with a high content of NGLs must be processed in order to meet pipeline quality specifications and to be suitable for ultimate consumption. To the extent that natural gas is not processed and does not meet pipeline quality specifications, this unprocessed natural gas and its associated crude oil production may be subject to being shut-in (i.e., not produced). Therefore, producers are motivated to reach contractual arrangements that are acceptable to gas processors in order for gas processing services to be available on a continuous basis (e.g., through contracts that do not expose the processors to natural gas price fluctuations). During periods of extreme commodity price fluctuations, we generally have the right under margin band/keepwhole arrangements to withhold processing services from a customer should we and the producer be unsuccessful in reaching acceptable contractual arrangements.

Our gas processing business and NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each of our competitors has varying levels of financial and personnel resources and competition generally revolves around price, service and location issues. Our integrated system affords us flexibility in meeting our customers needs. While many companies participate in the gas processing business, few have a presence in significant downstream activities such as NGL fractionation and transportation, import/export services and NGL marketing as we do. Our competitive and/or leading strategic position and sizeable presence in these downstream businesses allows us to extract incremental value while offering our customers enhanced services, including comprehensive service packages.

At December 31, 2003, our NGL marketing activities utilize a fleet of approximately 670 railcars, the majority of which are under short and long-term leases. These railcars are used to deliver feedstocks to our facilities and to transport NGL products throughout the United States. We have rail loading/unloading facilities at Mont Belvieu, Texas; Breaux Bridge, Louisiana; Sorrento, Louisiana and Petal, Mississippi. These facilities service both our rail shipments and those of our customers.

This segment includes our 13.1% investment in VESCO, which owns an integrated complex comprised of the Venice gas processing plant, a fractionation facility, storage assets and gas gathering pipelines in the Gulf of Mexico. In addition, we own four NGL terminals (primarily in propane service) located in Bakersfield and Rocklin, California; Reno, Nevada and Albertville, Alabama that have an aggregate storage capacity of 0.1 million barrels of NGLs.

*NGL pipelines and storage*

Our NGL pipelines transport mixed NGLs and other hydrocarbons to fractionation plants, distribute and collect NGL products to and from petrochemical plants and refineries and deliver propane to customers along the Dixie pipeline and certain sections of the Mid-America Pipeline System. Our pipelines provide transportation services to customers on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including our NGL and petrochemical marketing activities, which are eliminated in consolidation). Typically, our NGL pipelines do not take title to the products they transport; rather, the shipper retains title and the associated commodity price risk.

In the markets we serve, we compete with a number of intrastate and interstate liquids pipeline companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operators. In general, our NGL pipelines compete with these entities in terms of transportation rates and service. We believe that our pipeline systems offer significant flexibility in rendering transportation services for our customers due to the large number of receipt and delivery points that we can offer to them.

Taken as a whole, this business area has not exhibited a significant degree of seasonality. However, propane transportation volumes are generally higher in the October through March timeframe due to increased use of propane for heating in the upper Midwest and southeastern United States. Conversely, mixed NGL transportation volumes are generally lower during the winter months as traditionally higher natural gas prices negatively affect NGL extraction economics at natural gas processing plants connected to the pipelines. In addition, volumes on the Lou-Tex NGL pipeline are generally higher during the April through September period due to gasoline blending activities at refineries in anticipation of the summer driving season.

The following table summarizes our NGL pipeline transportation and distribution networks at December 31, 2003. Our ownership interest in each pipeline is held either directly through a consolidated subsidiary or indirectly through a company in which we have an investment accounted for under the equity method.

| NGL and Petrochemical Pipelines | Length in Miles | Our Ownership Interest at December 31, 2003 |
|---|---|---|
| Mid-America Pipeline System | 7,226 | 98.0% |
| Dixie | 1,301 | 19.9% |
| Seminole | 1,281 | 78.4%(1) |
| Louisiana Pipeline System | 655 | Various(2) |
| Promix(3) | 410 | 33.3% |
| Lou-Tex NGL | 206 | 100.0% |
| HSC | 175 | 100.0% |
| Tri-States | 169 | 50.0%(4) |
| Chunchula | 143 | 100.0% |
| Belle Rose | 48 | 41.7% |
| Wilprise | 30 | 74.7%(5) |
| Total NGL and petrochemical pipelines | 11,644 | |

(1) We acquired an additional 10% ownership interest in Seminole from Texaco in May 2004, which increased our ownership interest in Seminole to 88.4%.
(2) Of the 655 total miles for this system, we own 100% of 559 miles; 32.2% of 43 miles; and 31.3% of the remaining 53 miles.
(3) The Promix gathering pipeline is an integral component of the NGL fractionation activities of Promix.
(4) We acquired an additional 16.7% ownership interest in Tri-States from Williams in October 2003 and an additional 16.7% ownership interest in Tri-States from Koch in April 2004. We currently have a 66.7% ownership interest in Tri-States
(5) We acquired an additional 37.4% ownership interest in Wilprise from Williams in October 2003.

*Mid-America Pipeline System*. The Mid-America Pipeline System (or Mid-America ) is a regulated 7,226-mile 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 Mid-America system crosses thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. We have operated this system since February 2003.

The Rocky Mountain 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 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 third-party pipeline connections. The Conway South pipeline connects the Conway hub with Kansas refineries and transports mixed NGLs from Conway, Kansas to the Hobbs hub (with interconnections to the Seminole Pipeline System at the Hobbs hub). We also own fifteen unregulated propane terminals that are an integral part of the Mid-America system.

Approximately 60% of the volumes transported on the Mid-America system are mixed NGLs originating from natural gas processing plants located in the Permian Basin in West Texas, the Hugoton Basin of southwestern Kansas, the San Juan Basin of northwest New Mexico, and the Green River Basin of southwestern Wyoming. The remaining volumes are generally purity NGL products originating from NGL fractionators in the mid-continent areas of Kansas, Oklahoma, and Texas, as well as deliveries from Canada.

*Dixie*. The Dixie pipeline is a regulated 1,301-mile propane pipeline system extending from Mont Belvieu, Texas and Louisiana to markets in the southeastern United States. Propane supplies transported on this system primarily originate from southeast Texas, southern Louisiana and Mississippi. We currently estimate that Dixie transports approximately 50% of the propane requirements in the markets it serves. An affiliate of ConocoPhillips operates the pipeline.

*Seminole*. Seminole is a regulated 1,281-mile pipeline that transports mixed NGLs and NGL products from the Hobbs hub on the Texas-New Mexico border and the Permian Basin area to Mont Belvieu, Texas. The Seminole pipeline is interconnected with the Mid-America system at the Hobbs hub. The primary source of throughput for Seminole is the volume originating from the Mid-America system. In general, volumes transported by Seminole are ultimately used by petrochemical plants that manufacture various products in southeast Texas. We have operated this pipeline since February 2003.

*Louisiana Pipeline System*. The Louisiana Pipeline System is a 655-mile network of nine NGL pipelines located in Louisiana. This system transports mixed NGLs and NGL products originating in southern Louisiana and Texas and serves a variety of customers including major refineries and petrochemical companies along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other facilities located in Louisiana. We operate all but 43 miles of this system.

*Promix.* The Promix pipeline is a 410-mile NGL gathering pipeline that gathers mixed NGLs from 12 natural gas processing plants in Louisiana for delivery to the Promix NGL fractionator. This pipeline is an integral part of the Promix NGL fractionation facility.

*Lou-Tex NGL.* The Lou-Tex NGL pipeline system consists of a 206-mile NGL pipeline used to provide transportation services for NGL products and refinery grade propylene between the Louisiana and Texas markets. We also use this pipeline to transport mixed NGLs from certain of our Louisiana gas processing plants to our Mont Belvieu NGL fractionation facility. We operate this pipeline.

*HSC*. The HSC pipeline system is a collection of NGL and petrochemical pipelines aggregating 175 miles in length extending from our Houston Ship Channel import/export terminal facility to Mont Belvieu, Texas. These pipelines are used to deliver NGL products to third-party petrochemical plants and refineries as well as to deliver feedstocks to our Mont Belvieu facilities. This system is also used to transport MTBE produced by BEF to delivery locations along the Houston Ship Channel. We operate this system.

*Tri-States, Belle Rose and Wilprise*. We have ownership interests in the Tri-States, Belle Rose and Wilprise NGL pipelines, which supply mixed NGLs to the BRF, Norco and Promix NGL fractionators. The mixed NGLs transported on these systems originate from gas processing facilities located along the Mississippi, Alabama and Louisiana Gulf Coast.

The Tri-States pipeline is a l69-mile NGL pipeline that extends from Mobile Bay, Alabama to near Kenner, Louisiana and is operated by BP. The Belle Rose pipeline is a 48-mile NGL pipeline operated by us that extends from the interconnect with the Tri-States pipeline near Kenner, Louisiana to the Promix NGL fractionator. The Wilprise pipeline is a 30-mile NGL pipeline that extends from the interconnect with the Tri-States pipeline near Kenner, Louisiana to Sorrento, Louisiana. We have operated the Wilprise pipeline since February 2003.

*Chunchula*. The Chunchula pipeline system is a 143-mile NGL pipeline extending from the Alabama-Florida border to our storage facilities in Petal, Mississippi for further distribution. We operate this pipeline.

*NGL pipeline utilization*

The maximum number of barrels that these systems can transport per day depends upon the operating balance achieved at a given time between various segments of the system. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacity of the systems cannot be stated. As shown in the following table, the utilization rates of our principal NGL pipelines are measured in terms of throughput (in MBPD, on a net basis).

| | For Year Ended December 31, | | |
|---|---|---|---|
| **NGL and Petrochemical Pipelines** | **2003** | **2002** | **2001** |
| Mid-America Pipeline System (1) | 580 | 641 | n/a |
| Dixie | 21 | 21 | 26 |
| Seminole (1) | 194 | 202 | n/a |
| Louisiana Pipeline System | 190 | 179 | 138 |
| Lou-Tex NGL | 36 | 38 | 29 |
| HSC | 136 | 134 | 133 |
| Tri-States, Wilprise and Belle Rose | 35 | 44 | 36 |
| Chunchula | 4 | 5 | 5 |
| Total net volume of NGL and petrochemical pipelines | 1,196 | 1,264 | 367 |

(1) We acquired ownership interests in these systems in July 2002. The 2002 throughput rates reflect the five-month period that we owned interests in these assets (August 2002 through December 2002).

When compared to 2002, throughput rates for certain of our NGL pipelines in 2003 were lower due to a combination of (i) decreased demand for NGLs by the petrochemical industry and (ii) lower NGL extraction rates at domestic natural gas processing facilities. Volumes recorded for the Mid-America and Seminole systems were particularly affected by lower NGL extraction rates by natural gas processing facilities located in the Rocky Mountains.

*NGL and petrochemical storage*

Our NGL and petrochemical storage facilities are integral parts of our pipeline operations. In general, our underground storage wells are used to store mixed NGLs, NGL products and petrochemical products for customers and ourselves. The profitability of our storage operations is primarily dependent upon the volume of material stored and the level of fees charged.

Our principal storage operations are primarily determined by the operational requirements of our customers in the petrochemical industry. We usually experience an increase in the demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn down for heating needs.

The following table summarizes the practical (or useable) capacity of the storage assets we utilize and our ownership of such practical capacity by state at December 31, 2003.

| NGL and Petrochemical Storage Assets by State | Practical Capacity, MMBbls | Our Ownership of Practical Capacity, MMBbls |
|---|---|---|
| Texas | 94.1 | 93.8 |
| Louisiana | 32.5 | 14.3 |
| Mississippi | 12.0 | 9.5 |
| Iowa | 0.5 | 0.5 |
| Nebraska | 0.3 | 0.3 |
| Oklahoma | 0.1 | 0.1 |
| Total NGL and petrochemical storage capacity | 139.5 | 118.5 |

Our primary storage facilities are located at Mont Belvieu, Texas. We own and operate 90.5 MMBbls of practical storage capacity at Mont Belvieu. We also own storage facilities located at Breaux Bridge, Napoleonville, Sorrento and Venice, Louisiana having a practical capacity of 32.5 MMBbls. Our Mississippi storage assets are comprised of facilities located at or near Petal and Hattiesburg having a practical capacity of 12 MMBbls. Of the facilities located in Louisiana and Mississippi, we operate those located in Breaux Bridge and Napoleonville, Louisiana and Petal, Mississippi. Affiliates of Dynegy and Shell operate the remaining facilities. In connection with our Mid-America and Seminole pipeline systems, we own 20 underground NGL and petrochemical storage wells located in four states. The Mid-America and Seminole storage facilities have a practical storage capacity of 4.5 MMBbls.

Our storage wells allow us to optimize throughput on our pipeline systems and maintain operational efficiency. When used in conjunction with our processing plant operations, storage wells allow us to mix various batches of feedstock and maintain both a sufficient supply and stable composition of feedstock to our fractionation facilities. At times, we provide some of our processing customers with short-term storage services (typically 30 days or less) at nominal fees when they cannot take immediate delivery of products. Segment revenues include fees charged to our NGL and petrochemical marketing activities for their use of the storage facilities. These intrasegment revenues and expenses are eliminated in consolidation.

We also store products for customers in our wells for a fee. The amount of storage capacity available for this type of storage activity varies daily depending on our processing requirements. Our competitors in this area are other storage and pipeline companies such as TEPPCO and Dynegy. Major oil and gas companies such as Exxon Mobil and ConocoPhillips occasionally use their proprietary storage assets in this role, thereby entering into competition with us and other providers. We compete with other service providers primarily in terms of the fees charged, pipeline connections and dependability. We believe that the integrated nature of our processing, pipeline and import/export operations provide our storage customers access to a competitively priced, flexible and dependable network of assets.

*NGL import and export facilities*

*Houston Ship Channel Import/Export Terminal.* We lease and operate an NGL import facility located on the Houston Ship Channel that enables NGL tankers to be offloaded at their maximum unloading rate of 10,000 barrels per hour, thus minimizing the amount of time that a tanker is idle and increasing the number of vessels that can be offloaded. This facility is primarily used to offload volumes bound for our facilities in Mont Belvieu. Import volumes are usually at their highest levels from April through September of each year due to lower international demand and pricing for NGLs relative to domestic levels in those months. Typically, our import cargoes originate from North Africa and North Sea production areas.

In addition, we own an NGL export facility located at the same terminal as our import facility. Our export facility includes an NGL products chiller and related equipment used for loading refrigerated marine tankers for third-party exporters. Our export facility can load vessels with refrigerated propane and butane at rates up to 5,000 barrels per hour. In general, export cargoes shipped from this facility are destined for Mexico, Central and South America, Europe and the Far East (Japan, Korea and China). Export volumes are generally higher during the winter months due to increased propane exports.

Dynegy and Dow own facilities that are the primary competitors of our NGL import facility. Our primary competitors in the NGL export services market are Dynegy and ChevronTexaco. Both the import and export operations compete with third-party operations primarily in terms of service, such as the ability to quickly load or offload vessels. Our competitive position is enhanced because our extensive storage and pipeline assets at Mont Belvieu allow us to load and offload ships very efficiently. The profitability of import and export activities primarily depends upon the quantities loaded and offloaded and the fees we charge associated with each activity.

Due to the timing and logistics of ship and barge loading and offloading activities, we measure utilization in terms of volumes loaded and offloaded through our import/export facilities. The following table shows the volume for each facility over the last three years (in MBPD, on a net basis):