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

FORM 10-K

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

For the fiscal year ended December 31, 2002

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0582150**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

333 Clay Street, Suite 1600
Houston, Texas 77002
(Address of principal executive offices)
(Zip Code)

(713) 646-4100
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Units	New York Stock Exchange

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

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

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

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

The aggregate value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $644,934,579 on June 28, 2002, based on $25.79 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 21, 2003, there were outstanding 38,240,939 Common Units, 1,307,190 Class B Common Units and 10,029,619 Subordinated Units.

DOCUMENTS INCORPORATED BY REFERENCE: None

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
2002 FORM 10-K ANNUAL REPORT

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FORWARD-LOOKING STATEMENTS

All statements, other than statements of historical fact, included in this report are forward-looking statements, including, but not limited to, statements identified by the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast," and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- abrupt or severe production declines or production interruptions in outer continental shelf production located offshore California and transported on the All American Pipeline;
- declines in volumes shipped on the Basin Pipeline and our other pipelines by third party shippers;
- the availability of adequate supplies of and demand for crude oil in the areas in which we operate;
- the effects of competition;
- the success of our risk management activities;
- the impact of crude oil price fluctuations;
- the availability (or lack thereof) of acquisition or combination opportunities;
- successful integration and future performance of acquired assets;
- continued creditworthiness of, and performance by, counterparties;
- successful third-party drilling efforts in areas in which we operate pipelines or gather crude oil;
- our levels of indebtedness and our ability to receive credit on satisfactory terms;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- the impact of current and future laws and governmental regulations;
- the currency exchange rate of the Canadian dollar;
- environmental liabilities that are not covered by an indemnity or insurance;
- fluctuations in the debt and equity markets; and
- general economic, market or business conditions.

Other factors described herein, such as the recent disruptions in industry credit markets discussed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read "Risk Factors Related to Our Business" discussed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations." Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

PART I

Items 1 and 2. *Business And Properties*

General

We are a publicly traded Delaware limited partnership (the “Partnership”) engaged in interstate and intrastate marketing, transportation and terminalling of crude oil and marketing of liquefied petroleum gas (“LPG”). We were formed in September 1998 to acquire and operate the midstream crude oil business and assets of Plains Resources Inc. and its wholly-owned subsidiaries (“Plains Resources”) as a separate, publicly traded master limited partnership. We completed our initial public offering in November 1998. Immediately after our initial public offering, Plains Resources owned 100% of our general partner interest and an overall effective ownership in the Partnership of 57% (including the 2% general partner interest and common and subordinated units owned by it). As discussed below, Plains Resources’ effective ownership interest in the Partnership has been reduced substantially.

In May 2001, senior management and a group of financial investors entered into a transaction with Plains Resources to acquire majority control of our general partner and a majority of the outstanding subordinated units. The transaction closed in June 2001 and, for purposes of this report, is referred to as the “General Partner Transition.” As a result of this transaction and subsequent equity offerings, Plains Resources’ overall effective ownership in us was reduced to approximately 25%. See Item 12. “Security Ownership of Certain Beneficial Owners and Management.” In addition, certain senior officers of the general partner that previously were also officers of Plains Resources, terminated their affiliation with Plains Resources and now devote 100% of their efforts to the management of the Partnership.

The general partner interest is now held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.’s general partner. Plains All American GP LLC manages our operations and activities and employs our officers and personnel. Unless the context otherwise requires, we use the term “general partner” to refer to both Plains AAP, L.P. and Plains All American GP LLC. We use the phrase “former general partner” to refer to the subsidiary of Plains Resources that formerly held the general partner interest.

Our operations are concentrated in Texas, Oklahoma, California and Louisiana and in the Canadian provinces of Alberta and Saskatchewan, and can be categorized into two primary business activities:

- *Crude Oil Pipeline Transportation Operations*. We own and operate over 5,600 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting crude oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.
- *Gathering, Marketing, Terminalling and Storage Operations*. We own and operate approximately 22.7 million barrels of above-ground crude oil terminalling and storage facilities, including tankage associated with our pipeline systems. These facilities include a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to in this report as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for NYMEX crude oil futures contracts. Our terminalling and storage operations generate revenue through a combination of storage and throughput charges to third parties. We also utilize our storage tanks to counter-cyclically balance our gathering and marketing operations and to execute different hedging strategies to stabilize profits and reduce the negative impact of crude oil market volatility. See “—Crude Oil Volatility; Counter-Cyclical Balance; Risk Management.” Our gathering and marketing operations include:
  - the purchase of crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities;
  - the transportation of crude oil on trucks, barges and pipelines;

- the subsequent resale or exchange of crude oil at various points along the crude oil distribution chain; and
- the purchase of LPG from producers, refiners and other marketers, and the sale of LPG to wholesalers, retailers and industrial end users.

Business Strategy

Our business strategy is to capitalize on the regional crude oil and LPG supply and demand imbalances that exist in the United States and Canada by combining the strategic location and unique capabilities of our transportation and terminalling assets with our extensive marketing and distribution expertise to generate sustainable earnings and cash flow.

We intend to execute our business strategy by:

- increasing and optimizing throughput on our existing pipeline and gathering assets and realizing cost efficiencies through operational improvements;
- utilizing and expanding our Cushing Terminal and our other assets to service the needs of refiners and to profit from merchant activities that take advantage of crude oil pricing and quality differentials;
- selectively pursuing strategic and accretive acquisitions of crude oil and LPG transportation assets, including pipelines, gathering systems, terminalling and storage facilities and other assets that complement our existing asset base and distribution capabilities; and
- optimizing and expanding our Canadian operations to take advantage of anticipated increases in the volume and qualities of crude oil produced in Canada and exported to U.S. markets.

Financial Strategy

We believe that a major factor in our continued success will be our ability to maintain a low cost of capital and access to the capital markets. Since our initial public offering in 1998, we have consistently communicated to the financial community our intention to maintain a strong credit profile that we believe is consistent with our goal of achieving and maintaining an investment grade credit rating. We have targeted a general credit profile with the following attributes:

- an average long-term debt-to-total capitalization ratio of approximately 60% or less;
- an average long-term debt-to-EBITDA ratio of approximately 3.5x or less; and
- an average EBITDA-to-interest coverage ratio of approximately 3.3x or better.

As of December 31, 2002, we were within our targeted credit profile. In order for us to maintain our targeted credit profile and achieve growth through acquisitions, we intend to fund acquisitions using approximately equal proportions of equity and debt. Because it is likely that acquisitions will initially be financed using debt and it is difficult to predict the actual timing of accessing the market to raise equity, from time to time we may be temporarily outside the parameters of our targeted credit profile.

In February 2003, Standard & Poor’s upgraded our corporate credit rating to investment grade, assigning us a rating of BBB-, stable outlook. In September 2002, Moody’s Investor Services upgraded our senior implied credit rating to Ba1, stable outlook. You should note that a credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time.

Competitive Strengths

We believe that the following competitive strengths position us to successfully execute our business strategy:

- ***Our pipeline assets are strategically located and have additional capacity***. Our primary crude oil pipeline transportation and gathering assets are located in prolific oil producing regions and are connected, directly or indirectly, with our terminalling and storage assets that service major North American refinery and distribution markets, where we have strong business relationships. These assets are strategically positioned to maximize the value of our crude oil by transporting it to major trading locations and premium markets. Our pipeline networks currently possess additional capacity that can accommodate increased demand.
- ***Our Cushing Terminal is strategically located, operationally flexible and readily expandable***. Our Cushing Terminal interconnects with the Cushing Interchange's major inbound and outbound pipelines, providing access to both foreign and domestic crude oil. Our Cushing Terminal is the most modern large-scale terminalling and storage facility at the Cushing Interchange, incorporating (1) operational enhancements designed to safely and efficiently terminal, store, blend and segregate large volumes and multiple varieties of crude oil and (2) extensive environmental safeguards. Collectively, our Phase II expansion project, which became operational in July 2002, and our Phase III expansion project, which became operational in January 2003, increased the total capacity of our Cushing Terminal by approximately 70% to approximately 5.3 million barrels. We believe that the facility can be further expanded to meet additional demand should market conditions warrant. In addition, we own approximately 17.4 million barrels of above-ground crude oil terminalling and storage assets elsewhere in the United States and Canada that complement our Cushing Terminal and enable us to serve the needs of our customers.
- ***We possess specialized crude oil market knowledge***. We believe our business relationships with participants in all phases of the crude oil distribution chain, from crude oil producers to refiners, as well as our own industry expertise, provide us with an extensive understanding of the North American physical crude oil markets.
- ***Our business activities are counter-cyclically balanced***. We believe that our terminalling and storage activities and our gathering and marketing activities are counter-cyclical. We believe that this balance of activities, combined with pipeline transportation operations, has a stabilizing effect on our cash flow from operations.
- ***We have the financial flexibility to continue to pursue expansion and acquisition opportunities***. We believe we have significant resources to finance strategic expansion and acquisition opportunities, including our ability to issue additional partnership units, borrow under our credit facility and issue additional notes in the long-term debt capital markets. The amount of unused capacity available under our revolving credit facility at December 31, 2002, was approximately $436.9 million. Our usage is subject to covenant compliance. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities and Long-Term Debt."
- ***We have an experienced management team whose interests are aligned with those of all of our stakeholders***. Our executive management team has an average of more than 20 years industry experience, with an average of over 15 years with us or our predecessors and affiliates. Members of our senior management team own a 4% interest in our general partner and, through restricted unit grants and options, own significant contingent equity incentives that vest only if we achieve specified performance objectives. In addition, our senior management team collectively owns approximately 300,000 common and subordinated units.

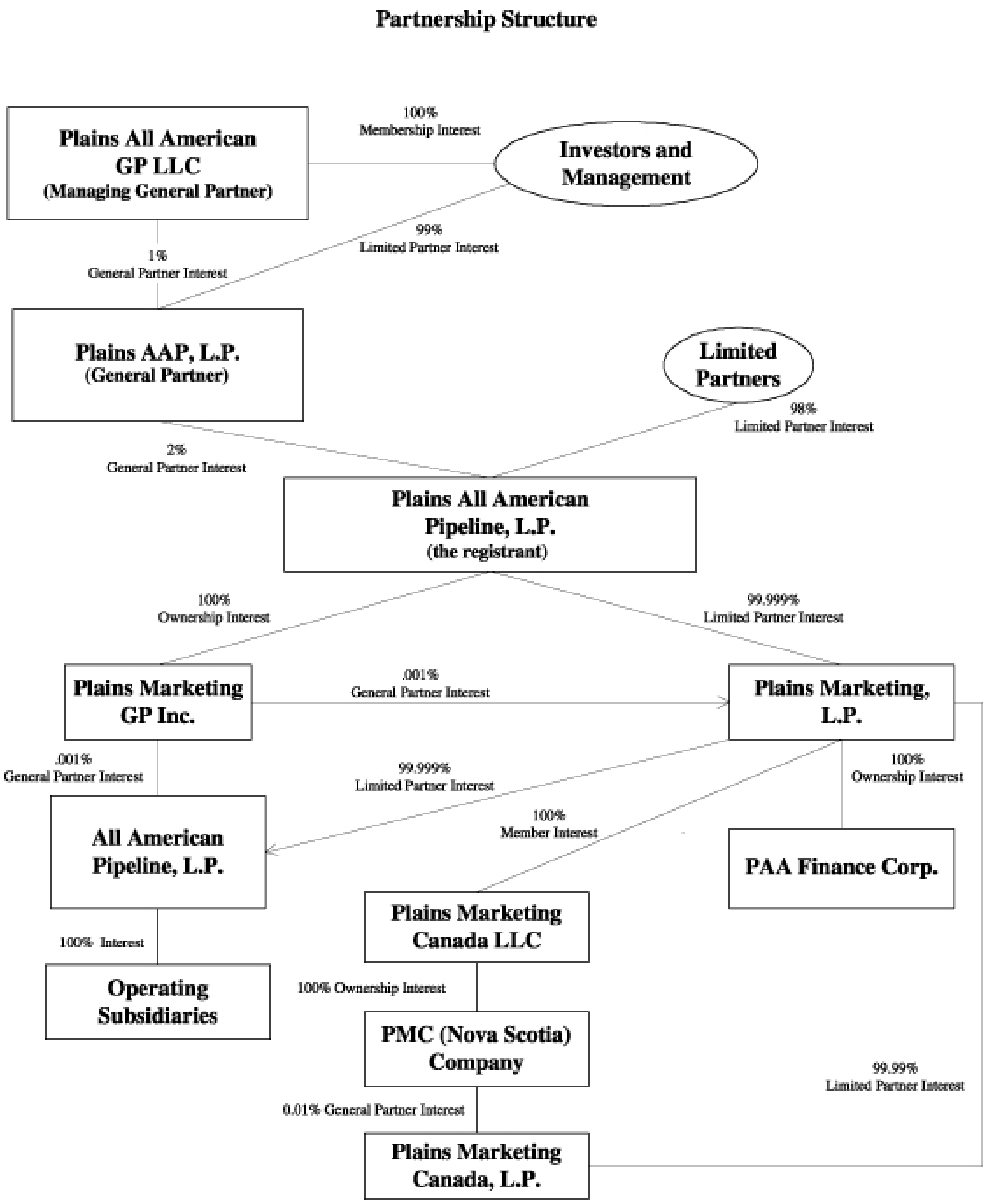
Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our interests in our subsidiaries through two operating partnerships, Plains Marketing, L.P. and All American Pipeline, L.P. Our Canadian operations are conducted through Plains Marketing Canada, L.P.

Our general partner, Plains AAP, L.P., is a limited partnership. Our general partner is managed by its general partner, Plains All American GP LLC, which has ultimate responsibility for conducting our business and managing our operations. Our general partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf. Canadian personnel are employed by Plains Marketing Canada L.P.'s general partner, PMC (Nova Scotia) Company.

Our general partner has responsibility for conducting our business and managing our operations, and owns all of the incentive distribution rights. These rights provide that our general partner receives an increasing percentage of cash distributions (in addition to its 2% general partner interest) as distributions reach and exceed certain threshold levels. See Item 5. "Market for the Registrant's Common Units and Related Unitholder Matters—Cash Distribution Policy."

The chart below depicts the current organization and ownership of Plains All American Pipeline, the operating partnerships and the subsidiaries.



Major Acquisitions and Dispositions

An integral component of our business strategy and growth objective is to acquire assets and operations that are strategic and complementary to our existing operations. We have established a target to make $200 million to $300 million per year in acquisitions, subject to availability of attractive assets on acceptable terms. Since 1998, we have completed numerous acquisitions for an aggregate purchase price of approximately $1.1 billion. In addition, from time to time we have sold assets that are no longer considered essential to our operations. Following is a brief description of major acquisitions and dispositions that have occurred since our initial public offering in November 1998.

Shell West Texas Assets

On August 1, 2002, we acquired interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas from Shell Pipeline Company LP and Equilon Enterprises LLC (the “Shell acquisition”). The primary assets included in the transaction are interests in the Basin Pipeline System (“Basin System”), the Permian Basin Gathering System (“Permian Basin System”) and the Rancho Pipeline System (“Rancho System”). The total purchase price of $324.4 million consisted of (i) $304.0 million in cash, which was borrowed under our revolving credit facility, (ii) approximately $9.1 million related to the settlement of pre-existing accounts receivable and inventory balances and (iii) approximately $11.3 million of estimated transaction and closing costs.

The acquired assets are primarily fee-based mainline crude oil pipeline transportation assets that gather crude oil in the Permian Basin and transport that crude oil to major market locations in the Mid-Continent and Gulf Coast regions. The acquired assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we provide storage and terminalling services. In addition, we believe that the Basin system is poised to benefit from potential shut-downs of refineries and other pipelines due to the shifting market dynamics in the West Texas area. As was contemplated at the time of the acquisition, the Rancho system will be taken out of service in March 2003, pursuant to the terms of its operating agreement. See “—Pipeline Operations—Pipeline Assets—Southwest U.S.—Rancho Pipeline System.”

Canadian Expansion

In early 2000, we articulated to the financial community our intent to establish a strong Canadian operation that substantially mirrors our operations in the United States. After evaluating the marketplace and analyzing potential opportunities, we consummated the two transactions detailed below in 2001. The combination of these assets, an established fee-based pipeline transportation business and a rapidly-growing, entrepreneurial gathering and marketing business, allowed us to optimize both businesses and establish a solid foundation for future growth in Canada.

CANPET Energy Group, Inc.

In July 2001, we purchased substantially all of the assets of CANPET Energy Group Inc., a Calgary-based Canadian crude oil and LPG marketing company, for approximately $42.0 million plus $25.0 million for additional inventory owned by CANPET. Approximately $18.0 million of the purchase price, payable in common units, was deferred subject to various performance standards being met. See Note 8 “Partners’ Capital and Distributions” in the “Notes to the Consolidated Financial Statements.” The principal assets acquired include a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and operating inventory.

Murphy Oil Company Ltd. Midstream Operations

In May 2001, we completed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately $161.0 million in cash, including financing and transaction costs. The purchase price included $6.5 million for excess inventory in the systems. The principal assets acquired include approximately 560 miles of crude oil and condensate mainlines (including dual lines on which condensate is shipped for blending purposes and blended crude is shipped in the opposite direction) and associated gathering and lateral lines, approximately 1.1 million barrels of crude oil storage and terminalling capacity located primarily in Kerrobert, Saskatchewan, approximately 254,000 barrels of pipeline linefill and tank inventories, and 121 trailers used primarily for crude oil transportation.

West Texas Gathering System

In July 1999, we completed the acquisition of the West Texas Gathering System from Chevron Pipe Line Company for approximately $36.0 million, including transaction costs. Financing for the amounts paid at closing was provided by a draw under a previous credit facility. The assets acquired include approximately 420 miles of crude oil mainlines, approximately 295 miles of associated gathering and lateral lines, and approximately 2.9 million barrels of tankage located along the system.

Scurlock Permian

In May 1999, we completed the acquisition of Scurlock Permian LLC ("Scurlock") and certain other pipeline assets from Marathon Ashland Petroleum LLC. Including working capital adjustments and closing and financing costs, the cash purchase price was approximately $141.7 million. Financing for the acquisition was provided through $117.0 million of borrowings and the sale of 1.3 million Class B Common Units to our former general partner for total cash consideration of $25.0 million.

Scurlock, previously a wholly owned subsidiary of Marathon Ashland Petroleum, was engaged in crude oil transportation, gathering and marketing. The assets acquired included approximately 2,300 miles of active pipelines, numerous storage terminals and a fleet of trucks. The largest asset consisted of an approximately 920-mile pipeline and gathering system located in the Spraberry Trend in West Texas that extends into Andrews, Glasscock, Martin, Midland, Regan and Upton Counties, Texas. The assets we acquired also included approximately one million barrels of crude oil linefill.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of midstream crude oil assets. Such acquisition efforts involve participation by us in processes that have been made public, involve a number of potential buyers and are commonly referred to as "auction" processes, as well as situations where we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. In connection with these activities, we routinely incur third party costs, which are capitalized and deferred pending final outcome of the transaction. Deferred costs associated with successful transactions are capitalized as part of the transaction, while deferred costs associated with unsuccessful transactions are expensed at the time of such final determination. We can give you no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

All American Pipeline Linefill Sale and Asset Disposition

In March 2000, we sold to a unit of El Paso Corporation for $129.0 million the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas. Except for minor third party volumes, one of our subsidiaries, Plains Marketing, L.P., was the sole shipper on this segment of the pipeline since its predecessor acquired the line from the Goodyear Tire & Rubber Company in July 1998. We realized net proceeds of approximately $124.0 million after the associated transaction costs and estimated costs to remove equipment. We used the proceeds from the sale to reduce outstanding debt. We recognized a gain of approximately $20.1 million in connection with the sale.

We had suspended shipments of crude oil on this segment of the pipeline in November 1999. At that time, we owned approximately 5.2 million barrels of crude oil in the segment of the pipeline. We sold this crude oil from November 1999 to February 2000 for net proceeds of approximately $100.0 million, which were used for working capital purposes. We recognized an aggregate gain of approximately $44.6 million, of which approximately $28.1 million was recognized in 2000 in connection with the sale of the linefill.

Description of Segments and Associated Assets

Our business activities are conducted through two primary segments, Pipeline Operations, which for the year ended 2002 comprised approximately 55% of our Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"), and Gathering, Marketing, Terminalling and Storage Operations, which comprised the remaining 45%. Our operations are conducted in approximately 40 states in the United States and three provinces in Canada. The majority of our operations are conducted in Texas, Oklahoma, California, Louisiana and in the Canadian provinces of Alberta and Saskatchewan.

Following is a description of the activities and assets for each of our business segments:

Pipeline Operations

We own and operate over 5,600 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting crude oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.

Substantially all of our pipeline systems are operated from one of two central control rooms with computer systems designed to continuously monitor real-time operational data, including measurement of crude oil quantities injected in and delivered through the pipelines, product flow rates and pressure and temperature variations. This monitoring and measurement technology allows us to efficiently batch differing crude oil types with varying characteristics through the pipeline systems. The systems are designed to enhance leak detection capabilities, sound automatic alarms in the event of operational conditions outside of pre-established parameters and provide for remote-controlled shut-down of pump stations on the pipeline systems. Pump stations, storage facilities and meter measurement points along the pipeline systems are linked by telephone, microwave, satellite or radio communication systems for remote monitoring and control, which reduces our requirement for full-time site personnel at most of these locations.

We perform scheduled maintenance on all of our pipeline systems and make repairs and replacements when necessary or appropriate. We attempt to control corrosion of the mainlines through the use of corrosion inhibiting chemicals injected into the crude stream, external coatings and anode bed based or impressed current cathodic protection systems. Maintenance facilities containing equipment for pipe repairs, spare parts and trained response personnel are strategically located along the pipelines and in concentrated operating areas. We believe that all of our pipelines have been constructed and are maintained in all material respects in accordance with applicable federal, state and local laws and regulations, standards prescribed by the American Petroleum Institute and accepted industry practice. See "—Regulation—Pipeline and Storage Regulation."

Following is a description of our major pipeline assets in the United States and Canada, grouped by geographic location:

Pipeline Assets

Southwest U.S.

Basin Pipeline System. The Basin System, acquired in the Shell acquisition, is a 514-mile mainline, telescoping crude oil system with a capacity ranging from approximately 144,000 barrels per day to 394,000 barrels per day depending on the segment. System throughput (as measured by system deliveries) was approximately 221,000 barrels per day (net to our interest) from the acquisition date to the end of 2002. The Basin System consists of three primary movements of crude oil: (1) barrels are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland, where they are exchanged and/or further shipped to refining centers; (2) barrels are shipped by refiners to the Mid-Continent region on the Midland to Wichita Falls segment and the Wichita Falls to Cushing segment; and (3) foreign and Gulf of Mexico barrels are delivered into Basin at Wichita Falls and shipped to Cushing for further distribution to Mid-Continent or Midwest refineries. The size of the pipe ranges from 20 to 24 inches in diameter. The Basin system also includes approximately 5.8 million barrels (5.0 million barrels, net to our interest) of crude oil storage capacity located along the system. Our ownership interest in the system is approximately 87%. TEPPCO Partners, L.P. owns the remaining interest in the system. The Basin system is subject to tariff rates regulated by the Federal Energy Regulatory Commission (the "FERC"). See "—Regulation—Transportation Regulation."

West Texas Gathering System. The West Texas Gathering System is a common carrier crude oil pipeline system located in the heart of the Permian Basin producing area, and includes approximately 420 miles of crude oil mainlines and approximately 295 miles of associated gathering and lateral lines. The West Texas Gathering System has the capability to transport approximately 190,000 barrels per day. Total system volumes were approximately 78,000 barrels per day in 2002. Chevron USA has agreed to transport its equity crude oil production from fields connected to the West Texas Gathering System on the system through July 2011 (representing approximately 20,000 barrels per day, or 26% of the total system volumes during 2002). The system also includes approximately 2.9 million barrels of crude oil storage capacity, located primarily in Monahans, Midland, Wink and Crane, Texas.

Permian Basin Gathering System. The Permian Basin System, acquired in the Shell acquisition, is comprised of approximately 17 gathering systems and nine trunk lines with connecting injection stations and storage facilities. In total, the system consists of 927 miles of pipe and primarily transports crude oil from wells in the Permian Basin to the Basin System. The Permian Basin System gathered approximately 62,000 barrels per day from the acquisition date to the end of 2002. The Permian Basin System includes approximately 3.2 million barrels of crude oil storage capacity.

Spraberry Pipeline System. The Spraberry Pipeline System, acquired in the Scurlock acquisition, gathers crude oil from the Spraberry Trend of West Texas and transports it to Midland, Texas, where it interconnects with the West Texas Gathering System and other pipelines. The Spraberry Pipeline System consists of approximately 920 miles of pipe of varying diameter, and has a throughput capacity of approximately 50,000 barrels of crude oil per day. The Spraberry Trend is one of the largest producing areas in West Texas, and we are one of the largest gatherers in the Spraberry Trend. For the year ended December 31, 2002, the Spraberry Pipeline System gathered approximately 35,000 barrels per day of crude oil. The Spraberry Pipeline System also includes approximately 364,000 barrels of tank capacity located along the pipeline.

Rancho Pipeline System. The Rancho System, acquired in the Shell acquisition, is a 24-inch, 458-mile mainline crude oil system with a capacity of approximately 187,000 barrels per day. During 2002, the system operated at approximately 50% of capacity. We operate the Rancho System which transports crude oil from McCamey, Texas, to the Houston Ship Channel where it connects to the Houston refining complex. The Rancho System includes approximately 1.2 million barrels of crude oil storage capacity (0.7 million barrels, net to our interest). Our ownership interest in the system ranges from approximately 46% to 59% depending upon the segment. The remaining interests in the system are owned by BP Amoco, Marathon Ashland, Crown Central and TEPPCO. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminates in March 2003. Upon termination, the agreement requires the owners to take the pipeline system out of service. Accordingly, we have notified our shippers that we will not accept nominations for movements after February 28, 2003. As contemplated at the time of the Shell acquisition, plans are currently under way to purge and idle portions of the pipeline system subject to final determination of the disposition of the system. During 2001, total volumes shipped from West Texas to the Houston Ship Channel on the Rancho system approximated 83,000 barrels per day. These volumes averaged approximately 91,000 barrels per day from the acquisition date to the end of 2002. Once the Rancho System is shut down, these volumes become candidates for shipment on the Basin System.

Dollarhide Pipeline System. The Dollarhide Pipeline System, acquired from Unocal Pipeline Company in October 2001, is a common carrier pipeline system that is located in West Texas. In 2002, the Dollarhide Pipeline System delivered approximately 6,000 barrels of crude oil per day into the West Texas Gathering System. The system also includes approximately 55,000 barrels of crude oil storage capacity along the system and in Midland.

Western U.S.

All American Pipeline System. The segment of the All American Pipeline that we retained following the sale of the line segment to El Paso is a common carrier crude oil pipeline system that transports crude oil produced from certain outer continental shelf, or OCS, fields offshore California to locations in California. See "—Major Acquisitions and Dispositions—All American Pipeline Linefill Sale and Asset Disposition." This segment is subject to tariff rates regulated by the FERC.

We own and operate the segment of the system that extends approximately 10 miles along the California coast from Las Flores to Gaviota (24-inch diameter pipe) and continues from Gaviota approximately 130 miles to our station in Emidio, California (30-inch pipe). Between Gaviota and our Emidio Station, the All American Pipeline interconnects with our San Joaquin Valley, or SJV, Gathering System as well as various third party intrastate pipelines, including the Unocap Pipeline System, the Equilon Pipeline System and the Pacific Pipeline.

The All American Pipeline currently transports OCS crude oil received at the onshore facilities of the Santa Ynez field at Las Flores and the onshore facilities of the Point Arguello field located at Gaviota. ExxonMobil, which owns all of the Santa Ynez production, and Plains Exploration and Production Company ("PXP") and other producers, which together own approximately 75% of the Point Arguello production, have entered into transportation agreements committing to transport all of their production from these fields on the All American Pipeline. These agreements, which expire in August 2007, provide for a minimum tariff with annual escalations based on specific composite indices. The producers from the Point Arguello field who do not have contracts with us have no other means of transporting their production and, therefore, ship their volumes on the All American Pipeline at the posted tariffs. Volumes attributable to PXP are purchased and sold to a third party under our marketing agreement with PXP before such volumes enter the All American Pipeline. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—General." The third party pays the same tariff as required in the transportation agreements. At December 31, 2002, the tariffs averaged $1.71 per barrel. The agreements do not require these owners to transport a minimum volume. A significant portion of our gross margin is derived from pipeline transportation margins associated with these two fields. For the year ended December 31, 2002, approximately $30 million, or 17%, of our gross margin was attributable to the Santa Ynez field and approximately $9 million, or 5% was attributable to the Point Arguello field.

The relative contribution to our gross margin from these fields has decreased from approximately 46% in the second half of 1998 to 22% in 2002, as the Partnership has grown and diversified through acquisitions and organic expansions and as a result of declines in volumes produced and transported from these fields, offset somewhat by an increase in pipeline tariffs. Over the last several years, transportation volumes received from the Santa Ynez and Point Arguello fields have declined from 92,000 and 60,000 average daily barrels, respectively, in 1995 to 50,000 and 16,000 average daily barrels, respectively, for the year ended December 31, 2002. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline tariff revenues of approximately $3.1 million, based on an annual tariff of $1.71 per barrel.

The table below sets forth the historical volumes received from both of these fields for the past five years.

	Year Ended December 31,				
	2002	2001	2000	1999	1998
	(barrels in thousands)				
Average daily volumes received from:					
Port Arguello (at Gaviota)	16	18	18	20	26
Santa Ynez (at Las Flores)	50	51	56	59	68
Total	66	69	74	79	94

SJV Gathering System. The SJV Gathering System is connected to most of the major fields in the San Joaquin Valley. The SJV Gathering System was constructed in 1987 with a design capacity of approximately 140,000 barrels per day. The system consists of a 16-inch pipeline that originates at the Belridge station and extends 45 miles south to a connection with the All American Pipeline at the Pentland station. The SJV Gathering System also includes approximately 600,000 barrels of tank capacity, which can be used to facilitate movements along the system as well as to support our other activities.

The table below sets forth the historical volumes received into the SJV Gathering System for the past five years.

	Year Ended December 31,				
	2002	2001	2000	1999	1998
	(barrels in thousands)				
Total average daily volumes	73	61	60	84	85

Butte Pipeline System. We own an approximate 22% equity interest in Butte Pipe Line Company, which in turn owns the Butte Pipeline System, a 373-mile mainline system that runs from Baker, Montana to Guernsey, Wyoming. The Butte Pipeline System is connected to the Poplar Pipeline System, which in turn is connected to the Wascana Pipeline System, which is located in our Canadian Region and is wholly owned by us. The total system volumes for Butte Pipeline System during 2002 were approximately 71,000 barrels of crude oil per day (approximately 16,000 barrels per day, net to our 22% interest).

U.S. Gulf Coast

Sabine Pass Pipeline System. The Sabine Pass Pipeline System, acquired in the Scurlock acquisition, is a common carrier crude oil pipeline system. The primary purpose of the Sabine Pass Pipeline System is to gather crude oil from onshore facilities of offshore production near Johnson's Bayou, Louisiana, and deliver it to tankage and barge loading facilities in Sabine Pass, Texas. The Sabine Pass Pipeline System consists of approximately 35 miles of pipe ranging from 4 to 10 inches in diameter and has a throughput capacity of approximately 26,000 barrels of crude oil per day. In 2002, the system transported approximately 19,000 barrels of crude oil per day. The Sabine Pass Pipeline System also includes 245,000 barrels of tank capacity located along the pipeline.

Ferriday Pipeline System. The Ferriday Pipeline System, acquired in the Scurlock acquisition, is a common carrier crude oil pipeline system located in eastern Louisiana and western Mississippi. The Ferriday Pipeline System consists of approximately 570 miles of pipe ranging from 2 inches to 12 inches in diameter. In 2002, the Ferriday Pipeline System delivered approximately 9,000 barrels of crude oil per day to third party pipelines that supplied refiners in the Midwest. The Ferriday Pipeline System also includes approximately 332,000 barrels of tank capacity located along the pipeline.

East Texas Pipeline System. The East Texas Pipeline System, acquired in the Scurlock acquisition, is a proprietary crude oil pipeline system that in 2002 gathered approximately 20,000 barrels per day of crude oil in

East Texas and transported approximately 24,000 barrels of crude oil per day to Crown Central’s refinery in Longview, Texas. Crown Central’s deliveries are subject to a throughput and deficiency agreement, which extends through 2004. The East Texas Pipeline System also includes approximately 266,000 barrels of tank capacity located along the pipeline.

Red River Pipeline System. The Red River Pipeline System, acquired in 2003, is a 347-mile crude oil pipeline system that originates at Sabine in East Texas, and terminates near Cushing, Oklahoma. The Red River system has a capacity of up to 22,000 barrels of crude oil per day, depending upon the type of crude oil being transported. During 2002, the system transported approximately 8,000 barrels of crude oil per day while being operated by BP. The system also includes approximately 695,000 barrels of crude oil storage capacity. In 2003, we intend to connect the pipeline system to our Cushing Terminal.

Central U.S.

Illinois Basin Pipeline System. The Illinois Basin Pipeline System, acquired with the Scurlock acquisition, consists of common carrier pipeline and gathering systems and truck injection facilities in southern Illinois. The Illinois Basin Pipeline System consists of approximately 80 miles of pipe of varying diameter and in 2002 delivered approximately 3,500 barrels of crude oil per day to third party pipelines that supply refiners in the Midwest. For the year ended December 31, 2002, approximately 3,000 barrels of crude oil per day of the supply on this system came from fields operated by PXP, formerly Plains Resources.

Canada

Manito Pipeline System. The Manito Pipeline System, acquired in the Murphy acquisition, is a provincially regulated system located in Saskatchewan, Canada. The Manito Pipeline System is a 101-mile crude oil pipeline and a parallel 101-mile condensate pipeline that connects the North Saskatchewan Pipeline System and multiple gathering lines to the Enbridge system at Kerrobert. The Manito Pipeline System volumes were approximately 66,000 barrels of crude oil and condensate per day in 2002.

Milk River Pipeline System. The Milk River Pipeline System, acquired in the Murphy acquisition, is a National Energy Board (“NEB”) regulated system located in Alberta, Canada. The Milk River Pipeline System consists of three parallel 11-mile crude oil pipelines that connect the Bow River Pipeline in Alberta to the Cenex Pipeline at the United States border. The Milk River Pipeline System transported approximately 97,000 barrels of crude oil per day in 2002.

North Saskatchewan Pipeline System. The North Saskatchewan Pipeline System, acquired in the Murphy acquisition, is a provincially regulated system located in Saskatchewan, Canada. We operate the North Saskatchewan Pipeline System, which is a 34-mile crude oil pipeline and a parallel 34-mile condensate pipeline that connects to the Manito Pipeline at Dulwich. In 2002, the North Saskatchewan Pipeline System delivered approximately 6,000 barrels of crude oil and condensate per day into the Manito Pipeline. Our ownership interest in the North Saskatchewan Pipeline System is approximately 36%.

Cactus Lake/Bodo Pipeline System. The Cactus Lake/Bodo Pipeline System, acquired in the Murphy acquisition, is located in Alberta and Saskatchewan, Canada. The Bodo portion of the system is NEB-regulated, and the remainder is provincially regulated. We operate the Cactus Lake/Bodo Pipeline System, which is a 55-mile crude oil pipeline and a parallel 55-mile condensate pipeline that connects to our storage and terminalling facility at Kerrobert. In 2002, the Cactus Lake/Bodo Pipeline System transported approximately 26,000 barrels per day of crude oil and condensate. Our ownership interest in the Cactus Lake segment is 13.125% and our ownership interest in the Bodo Pipeline is 76.25%. We own various interests in the lateral lines in these systems.

Wascana Pipeline System. The Wascana Pipeline System, acquired in the Murphy acquisition, is an NEB-regulated system located in Saskatchewan, Canada. The Wascana Pipeline System is a 107-mile crude oil pipeline that connects to the Shell Pipeline system at the United States border near Raymond, Montana. In 2002, the Wascana Pipeline System transported approximately 10,000 barrels of crude oil per day.

Wapella Pipeline System. The Wapella Pipeline System is an approximately 79 mile, NEB-regulated system located in southeastern Saskatchewan and southwestern Manitoba. In 2002, the Wapella Pipeline System delivered approximately 10,000 barrels of crude oil per day to the Enbridge Pipeline at Cromer, Manitoba. The system also includes approximately 18,500 barrels of crude oil storage capacity.

Gathering, Marketing, Terminalling and Storage Operations

The combination of our gathering and marketing operations and our terminalling and storage operations provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. The strategic use of our terminalling and storage assets in conjunction with our gathering and marketing operations provides us with the flexibility to optimize margins irrespective of whether a strong or weak market exists. Following is a description of our activities with respect to this segment.

Gathering and Marketing Operations

Crude Oil. The majority of our gathering and marketing activities are in the geographic locations previously discussed. These activities include:

- purchasing crude oil from producers at the wellhead and in bulk from aggregators at major pipeline interconnects and trading locations;
- transporting this crude oil on our own proprietary gathering assets or, when necessary or cost effective, assets owned and operated by third parties;
- exchanging this crude oil for another grade of crude oil or at a different geographic location, as appropriate, in order to maximize margins or meet contract delivery requirements; and
- marketing crude oil to refiners or other resellers.

We purchase crude oil from many independent producers and believe that we have established broad-based relationships with crude oil producers in our areas of operations. Gathering and marketing activities involve relatively large volumes of transactions with lower margins compared to pipeline and terminalling and storage operations.

The following table shows the average daily volume of our lease gathering and bulk purchases from 1998 through 2002:

	Year Ended December 31,				
	2002	2001	2000	1999	1998
	(barrels in thousands)				
Lease gathering purchases(1)	410	348	262	265	88
Bulk purchases(1)	80	46	28	138	98
Total volumes	490	394	290	403	186

(1) Prior period volume amounts have been adjusted (i) so that volumes associated with acquisitions represent weighted average daily amounts during the year of acquisition, and (ii) for consistency of comparison between years.

Crude Oil Purchases. We purchase crude oil from producers under contracts that range in term from a thirty-day evergreen to three years. In a typical producer’s operation, crude oil flows from the wellhead to a separator where the petroleum gases are removed. After separation, the crude oil is treated to remove water, sand and other contaminants and is then moved into the producer’s on-site storage tanks. When the tank is full, the producer contacts our field personnel to purchase and transport the crude oil to market. We utilize our truck fleet and gathering pipelines and third party pipelines, trucks and barges to transport the crude oil to market. We own or lease approximately 300 trucks used for gathering crude oil.

We have a marketing agreement with Plains Resources, under which we are the exclusive marketer and purchaser for all of Plains Resources' equity crude oil production (including its subsidiaries that conduct exploration and production activities.) The marketing agreement provides that we will purchase for resale at market prices all of Plains Resources' equity crude oil production, for which we charge a fee of $0.20 per barrel. This fee will be adjusted every three years based upon then existing market conditions. The marketing agreement will terminate upon a "change of control" of Plains Resources or our general partner. In November 2001, the marketing agreement automatically extended for an additional three-year period. On December 18, 2002, Plains Resources completed a spin-off of one of its subsidiaries, PXP, to its shareholders. PXP is a successor participant to this marketing agreement. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—General."

Bulk Purchases. In addition to purchasing crude oil at the wellhead from producers, we purchase crude oil in bulk at major pipeline terminal locations. This oil is transported from the wellhead to the pipeline by major oil companies, large independent producers or other gathering and marketing companies. We purchase crude oil in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

Crude Oil Sales. The marketing of crude oil is complex and requires detailed current knowledge of crude oil sources and end markets and a familiarity with a number of factors including grades of crude oil, individual refinery demand for specific grades of crude oil, area market price structures for the different grades of crude oil, location of customers, availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil to the appropriate customer. We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions, at market prices for terms ranging from one month to three years.

We establish a margin for crude oil we purchase by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX and over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil futures contracts as hedging devices. Except for pre-defined inventory positions, our policy is generally to purchase only crude oil for which we have a market, to structure our sales contracts so that crude oil price fluctuations do not materially affect the gross margin we receive, and to not acquire and hold crude oil, futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses. See "Crude Oil Volatility; Counter-Cyclical Balance; Risk Management." In November 1999, we discovered that this policy was violated, and we incurred $174.0 million in unauthorized trading losses, including estimated associated costs and legal expenses. In 2000, we recognized an additional $7.0 million charge related to the settlement of litigation for an amount in excess of established reserves. See "—Unauthorized Trading Losses."

Crude Oil Exchanges. We pursue exchange opportunities to enhance margins throughout the gathering and marketing process. When opportunities arise to increase our margin or to acquire a grade of crude oil that more closely matches our physical delivery requirement or the preferences of our refinery customers, we exchange physical crude oil with third parties. These exchanges are effected through contracts called exchange or buy-sell agreements. Through an exchange agreement, we agree to buy crude oil that differs in terms of geographic location, grade of crude oil or physical delivery schedule from crude oil we have available for sale. Generally, we enter into exchanges to acquire crude oil at locations that are closer to our end markets, thereby reducing transportation costs and increasing our margin. We also exchange our crude oil to be physically delivered at a later date, if the exchange is expected to result in a higher margin net of storage costs, and enter into exchanges based on the grade of crude oil, which includes such factors as sulfur content and specific gravity, in order to meet the quality specifications of our physical delivery contracts.

Producer Services. Crude oil purchasers who buy from producers compete on the basis of competitive prices and highly responsive services. Through our team of crude oil purchasing representatives, we maintain ongoing relationships with producers in the United States and Canada. We believe that our ability to offer high-quality field and administrative services to producers is a key factor in our ability to maintain volumes of purchased crude oil and to obtain new volumes. Field services include efficient gathering capabilities, availability of trucks, willingness to construct gathering pipelines where economically justified, timely pickup of crude oil from tank batteries at the lease or production point, accurate measurement of crude oil volumes received, avoidance of spills and effective management of pipeline deliveries. Accounting and other administrative services include securing division orders (statements from interest owners affirming the division of ownership in crude oil purchased by us), providing statements of the crude oil purchased each month, disbursing production proceeds to interest owners, and calculation and payment of ad valorem and production taxes on behalf of interest owners. In order to compete effectively, we must maintain records of title and division order interests in an accurate and timely manner for purposes of making prompt and correct payment of crude oil production proceeds, together with the correct payment of all severance and production taxes associated with such proceeds.

Liquefied Petroleum Gas and Other Petroleum Products. We also gather and market LPG and other petroleum products throughout the United States and Canada, concentrated primarily in Washington, California, Kansas, Michigan, Texas, Montana, Nebraska and the Canadian provinces of Alberta and Ontario. These activities include:

- purchasing LPG (primarily propane and butane) from producers at gas plants and in bulk at major pipeline terminal points and storage locations;
- transporting the LPG via common carrier pipelines, railcars and trucks to our own terminals and third party facilities for subsequent resale by them to retailers and other wholesale customers; and
- exchanging product to other locations to maximize margins and/or to meet contract delivery requirements.

We purchase LPG from numerous producers and have established long-term, broad-based relationships with LPG producers in our areas of operation. We purchase LPG directly from gas plants, major pipeline terminals and storage locations. Gathering and marketing activities for LPG typically consist of smaller volumes and generally higher margin per barrel transactions relative to crude oil.

LPG Purchases. We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that range from immediate delivery to one year in term. In a typical producer’s or refiner’s operation, LPG that is produced at the gas plant or refinery is fractionated into various components including propane and butane and then purchased by us for movement via tank truck, railcar or pipeline.

In addition to purchasing LPG at gas plants or refineries, we also purchase LPG in bulk at major pipeline terminal points and storage facilities from major oil companies, large independent producers or other LPG marketing companies. We purchase LPG in bulk when we believe additional opportunities exist to realize margins further downstream in our LPG distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

LPG Sales. The marketing of LPG is complex and requires detailed current knowledge of LPG sources and end markets and a familiarity with a number of factors including the various modes and availability of transportation, area market prices and timing and costs of delivering LPG to customers.

We sell LPG primarily to industrial end users and retailers, and limited volumes to other marketers. Propane is sold to small independent retailers who then transport the product via bobtail truck to residential consumers for home heating and to some light industrial users such as forklift operators. Butane is used by refiners for gasoline blending and as a diluent for the movement of conventional heavy oil production. Butane demand for use as heavy oil diluent has increased as supplies of Canadian condensate have declined.

We establish a margin for propane by transporting it in bulk, via various transportation modes, to our controlled terminals where we deliver the propane to our retailer customers for subsequent delivery to their individual heating customers. We also create margin by selling propane for future physical delivery to third party users, such as retailers and industrial users. Through these transactions, we seek to maintain a position that is substantially balanced between propane purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including floating price collar arrangements, financial swaps and crude oil and LPG-related futures contracts as hedging devices. Except for pre-defined inventory positions, our policy is generally to purchase only LPG for which we have a market, and to structure our sales contracts so that LPG spot price fluctuations do not materially affect the gross margin we receive. Margin is created on the butane purchased by delivering large volumes during the short refinery blending season through the use of our extensive leased railcar fleet and the use of third party storage facilities. We also create margin on butane by capturing the difference in price between condensate and butane when butane is used to replace condensate as a diluent for the movement of Canadian heavy oil production. While we seek to maintain a position that is substantially balanced within our LPG activities, as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions, from time to time we experience net unbalanced positions for short periods of time. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, our policies provide that any net imbalance may not exceed 200,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations.

LPG Exchanges. We pursue exchange opportunities to enhance margins throughout the gathering and marketing process. When opportunities arise to increase our margin or to acquire a volume of LPG that more closely matches our physical delivery requirement or the preferences of our customers, we exchange physical LPG with third parties. These exchanges are effected through contracts called exchange or buy-sell agreements. Through an exchange agreement, we agree to buy LPG that differs in terms of geographic location, type of LPG or physical delivery schedule from LPG we have available for sale. Generally, we enter into exchanges to acquire LPG at locations that are closer to our end markets in order to meet the delivery specifications of our physical delivery contracts.

Credit. Our merchant activities involve the purchase of crude oil for resale and require significant extensions of credit by our suppliers of crude oil. In order to assure our ability to perform our obligations under crude oil purchase agreements, various credit arrangements are negotiated with our crude oil suppliers. Such arrangements include open lines of credit directly with us, and standby letters of credit issued under our letter of credit facility.

When we market crude oil, we must determine the amount, if any, of the line of credit to be extended to any given customer. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. If we determine that a customer should receive a credit line, we must then decide on the amount of credit that should be extended. Since our typical sales transactions can involve tens of thousands of barrels of crude oil, the risk of nonpayment and nonperformance by customers is a major consideration in our business. We believe our sales are made to creditworthy entities or entities with adequate credit support.

We also have credit risk with respect to our sales of LPG; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that we have material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as sell LPG on a current basis to local distributors and retailers. In certain cases our customers prepay for their purchases, in amounts ranging from $0.05 per gallon to 100% of their contracted amounts. Generally, sales of LPG are settled within 30 days of the date of invoice.

During 2002, announcements of business failures, revelations of material misrepresentations and related financial restatements adversely affected several companies within the energy industry, resulting in a rapid deterioration in credit ratings. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Contingencies—Recent Disruptions in Industry Credit Markets."

Terminalling and Storage Operations

We own approximately 22.7 million barrels of terminalling and storage assets, including tankage associated with our pipeline and gathering systems. Our storage and terminalling operations increase our margins in our business of purchasing and selling crude oil and also generate revenue through a combination of storage and throughput charges to third parties. Storage fees are generated when we lease tank capacity to third parties. Terminalling fees, also referred to as throughput fees, are generated when we receive crude oil from one connecting pipeline and redeliver crude oil to another connecting carrier in volumes that allow the refinery to receive its crude oil on a ratable basis throughout a delivery period. Both terminalling and storage fees are generally earned from:

- refiners and gatherers that segregate or custom blend crudes for refining feedstocks;
- pipeline operators, refiners or traders that need segregated tankage for foreign cargoes;
- traders who make or take delivery under NYMEX contracts; and
- producers and resellers that seek to increase their marketing alternatives.

The tankage that is used to support our arbitrage activities positions us to capture margins in a contango market (when the oil prices for future deliveries are higher than the current prices) or when the market switches from contango to backwardation (when the oil prices for future deliveries are lower than the current prices). See "—Crude Oil Volatility; Counter-Cyclical Balance; Risk Management."

Our most significant terminalling and storage asset is our Cushing Terminal located at the Cushing Interchange. The Cushing Interchange is one of the largest wet-barrel trading hubs in the U.S. and the delivery point for crude oil futures contracts traded on the NYMEX. The Cushing Terminal has been designated by the NYMEX as an approved delivery location for crude oil delivered under the NYMEX light sweet crude oil futures contract. As the NYMEX delivery point and a cash market hub, the Cushing Interchange serves as a primary source of refinery feedstock for the Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. Our Cushing Terminal was constructed in 1993 to capitalize on the crude oil supply and demand imbalance in the Midwest. The Cushing Terminal is also used to support and enhance the margins associated with our merchant activities relating to our lease gathering and bulk purchasing activities. See "—Gathering and Marketing Operations—Bulk Purchases." In 1999, we completed our 1.1 million barrel Phase I expansion project, which increased the facility's total storage capacity to 3.1 million barrels. On July 1, 2002, we placed in service approximately 1.1 million barrels of tank capacity associated with our Phase II expansion of the Cushing Terminal, raising the facility's total storage capacity to approximately 4.2 million barrels. In January 2003, we placed in service our 1.1 million barrel Phase III expansion. The Phase II and III expansions increased the capacity of the Cushing Terminal by approximately 70% to a total of approximately 5.3 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks and twelve 270,000-barrel tanks, all of which are used to store and terminal crude oil. The Cushing Terminal also includes a pipeline manifold and pumping system that has an estimated throughput capacity of approximately 800,000 barrels per day. The Cushing Terminal is connected to the major pipelines and other terminals in the Cushing Interchange through pipelines that range in size from 10 inches to 24 inches in diameter.

The Cushing Terminal is designed to serve the needs of refiners in the Midwest. In order to service an expected increase in the volumes as well as the varieties of foreign and domestic crude oil projected to be transported through the Cushing Interchange, we incorporated certain attributes into the design of the Cushing Terminal including:

- multiple, smaller tanks to facilitate simultaneous handling of multiple crude varieties in accordance with normal pipeline batch sizes;
- dual header systems connecting most tanks to the main manifold system to facilitate efficient switching between crude grades with minimal contamination;
- bottom drawn sumps that enable each tank to be efficiently drained down to minimal remaining volumes to minimize crude oil contamination and maintain crude oil integrity during changes of service;
- mixer(s) on each tank to facilitate blending crude oil grades to refinery specifications; and
- a manifold and pump system that allows for receipts and deliveries with connecting carriers at their maximum operating capacity.

As a result of incorporating these attributes into the design of the Cushing Terminal, we believe we are favorably positioned to serve the needs of Midwest refiners to handle an increase in the number of varieties of crude oil transported through the Cushing Interchange. The pipeline manifold and pumping system of our Cushing Terminal is designed to support more than 10 million barrels of tank capacity and we have sufficient land holdings in and around the Cushing Interchange on which to construct additional tankage. Our tankage in Cushing ranges in age from brand new to approximately 10 years old and the average age is approximately 4.7 years old. In contrast, we estimate that of the approximately 21 million barrels of remaining tanks in Cushing owned by third parties, the average age is approximately 50 years and of that, approximately 9 million barrels has an average age of over 70 years. We believe that provides us with a competitive advantage over our competitors. In addition, we believe that we are well positioned to accommodate construction of replacement tankage that may be required as a result of the imposition of stricter regulatory standards and related attrition among our competitors' tanks in connection with the requirements of API 653. See "—Regulation—Pipeline and Storage Regulation."

Our Cushing Terminal also incorporates numerous environmental and operational safeguards. We believe that our terminal is the only one at the Cushing Interchange in which each tank has a secondary liner (the equivalent of double bottoms), leak detection devices and secondary seals. The Cushing Terminal is the only terminal at the Cushing Interchange equipped with aboveground pipelines. Like the pipeline systems we operate, the Cushing Terminal is operated by a computer system designed to monitor real-time operational data and each tank is cathodically protected. In addition, each tank is equipped with an audible and visual high-level alarm system to prevent overflows; a double seal floating roof designed to minimize air emissions and prevent the possible accumulation of potentially flammable gases between fluid levels and the roof of the tank; and a foam dispersal system that, in the event of a fire, is fed by a fully-automated fire water distribution network.

The following table sets forth throughput volumes for our terminalling and storage operations and quantity of tankage leased to third parties for our Cushing Terminal from 1998 through 2002.

	Year Ended December 31,				
	2002	2001	2000	1999	1998
	(barrels in thousands)				
Throughput volumes (average daily volumes)	110	94	59	72	69
Storage leased to third parties (average monthly volumes)[1]	1,067	2,136	1,437	1,743	890

(1) The level of tankage at Cushing that we allocate for our arbitrage activities (and therefore is not available for lease to third parties) varies throughout crude oil price cycles.

Crude Oil Volatility; Counter-Cyclical Balance; Risk Management

Crude oil prices have historically been very volatile and cyclical, with NYMEX benchmark prices ranging from as high as $40.00 per barrel to as low as $10.00 per barrel over the last 13 years. Gross margin from terminalling and storage activities is dependent on the throughput volume of crude oil stored, capacity leased to third parties, capacity that we use for our own activities, and the level of other fees generated at our terminalling and storage facilities. Gross margin from our gathering and marketing activities is dependent on our ability to sell crude oil at a price in excess of our aggregate cost. Although margins may be affected during transitional periods, these operations are not directly affected by the absolute level of crude oil prices, but are affected by overall levels of supply and demand for crude oil and relative fluctuations in market-related indices.

During periods when supply exceeds the demand for crude oil, the market for crude oil is often in contango, meaning that the price of crude oil for future deliveries is higher than current prices. A contango market has a generally negative impact on marketing margins, but is favorable to the storage business, because storage owners at major trading locations (such as the Cushing Interchange) can simultaneously purchase production at current prices for storage and sell at higher prices for future delivery.

When there is a higher demand than supply of crude oil in the near term, the market is backwardated, meaning that the price of crude oil for future deliveries is lower than current prices. A backwardated market has a positive impact on marketing margins because crude oil gatherers can capture a premium for prompt deliveries. In this environment, there is little incentive to store crude oil as current prices are above future delivery prices.

The periods between a backwardated market and a contango market are referred to as transition periods. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial affect on our aggregate gross margin. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the most difficult environment for our gathering, marketing, terminalling and storage activities. When the market is in contango, we will use our tankage to improve our gathering margins by storing crude oil we have purchased for delivery in future months that are selling at a higher price. In a backwardated market, we use and lease less storage capacity but increased marketing margins provide an offset to this reduced cash flow. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. References to counter-cyclical balance elsewhere in this report are referring to this relationship between our terminalling and storage activities and our gathering and marketing activities in transitioning crude oil markets.

As use of the financial markets for crude oil has increased by producers, refiners, utilities and trading entities, risk management strategies, including those involving price hedges using NYMEX futures contracts and derivatives, have become increasingly important in creating and maintaining margins. Such hedging techniques require significant resources dedicated to managing these positions. Our risk management policies and procedures are designed to monitor both NYMEX and over-the-counter positions and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities are implemented in accordance with such policies. We have a risk management function that has direct responsibility and authority for our risk policies, our trading controls and procedures and certain other aspects of corporate risk management.

Our policy is to purchase only crude oil for which we have a market, and to structure our sales contracts so that crude oil price fluctuations do not materially affect the gross margin we receive. Except for inventory transactions not to exceed 500,000 barrels, we do not acquire and hold crude oil futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses.

As a result of production and delivery variances associated with our lease purchase activities, from time to time we experience net unbalanced positions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in this controlled trading program for up to 500,000 barrels. This activity is monitored independently by our risk management function and must take place within predefined limits and authorizations. In order to hedge margins involving our physical assets and manage risks associated with our crude oil purchase and sale obligations, we use derivative instruments, including regulated futures and options transactions, as well as over-the-counter instruments. In analyzing our risk management activities, we draw a distinction between enterprise-level risks and trading-related risks. Enterprise-level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading-related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the core business; rather, those risks arise as a result of engaging in the trading activity. We have a Risk Management Committee that approves all new risk management strategies through a formal process. With the partial exception of the limited 500,000-barrel program, our approved strategies are intended to mitigate enterprise-level risks that are inherent in our core businesses of crude oil gathering and marketing and storage. Similarly, while we seek to maintain a position that is substantially balanced within our LPG activities, as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions, from time to time we experience net unbalanced positions for short periods of time. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, our policies provide that any net imbalance may not exceed 200,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility than in the past. This accounting treatment is discussed further in Note 2 “Summary of Significant Accounting Policies” in the “Notes to the Consolidated Financial Statements.”

Geographic Data

See Note 17 “Operating Segments” in the “Notes to the Consolidated Financial Statements.”

Customers

See Note 11 “Major Customers and Concentration of Credit Risk” in the “Notes to the Consolidated Financial Statements.”

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and demand for the crude oil by end users. We believe that high capital requirements, environmental considerations and the difficulty in acquiring rights-of-way and related permits make it unlikely that competing pipeline systems comparable in size and scope to our pipeline systems will be built in the foreseeable future. However, to the extent there are already third-party owned pipelines with excess capacity in the vicinity of our operations, we will be exposed to significant competition based on the incremental cost of moving an incremental barrel of crude oil.

We face intense competition in our gathering, marketing, terminalling and storage operations. Our competitors include other crude oil pipeline companies, the major integrated oil companies, their marketing affiliates and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours, and control greater supplies of crude oil.

Regulation

Our operations are subject to extensive regulations. We estimate that we are subject to regulatory oversight by over 70 federal, state, provincial and local departments and agencies, many of which are authorized by statute to issue and have issued laws and regulations binding on the oil pipeline industry, related businesses and individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, except for certain exemptions that apply to smaller companies, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Due to the myriad of complex federal, state, provincial and local regulations that may affect us, directly or indirectly, you should not rely on the following discussion of certain laws and regulations as an exhaustive review of all regulatory considerations affecting our operations.

Pipeline and Storage Regulation

Some of our petroleum pipelines and storage tanks in the United States are subject to regulation by the U.S. Department of Transportation ("DOT") with respect to the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. In addition, we must permit access to and copying of records, and must make certain reports available and provide information as required by the Secretary of Transportation. Comparable regulation exists in Canada and in some states in which we conduct intrastate common carrier or private pipeline operations.

Pipeline safety issues are currently receiving significant attention in various political and administrative arenas at both the state and federal levels. For example, recent federal rule changes require pipeline operators to: (1) develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities, and (2) establish pipeline integrity management programs. In particular, during 2000, the DOT adopted new regulations requiring operators of interstate pipelines to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could affect so-called "high consequence areas," including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release, and commercially navigable waterways. Segments of our pipelines are located in high consequence areas. The DOT rule requires us to evaluate pipeline conditions by means of periodic internal inspection, pressure testing, or other equally effective assessment means, and to correct identified anomalies. If, as a result of our evaluation process, we determine that there is a need to provide further protection to high consequence areas, then we will be required to implement additional spill prevention, mitigation and risk control measures for our pipelines, including enhanced damage prevention programs, corrosion control program improvements, leak detection system enhancements, installation of emergency flow restricting devices, and emergency preparedness improvements. The DOT rule also requires us to evaluate and, as necessary, improve our management and analysis processes for integrating available integrity-related data relating to our pipeline segments and to remediate potential problems found as a result of the required assessment and evaluation process. Based on currently available information, we estimate that the costs to implement this program will average approximately $1.9 million per year in 2003 and 2004. Such amounts incorporate approximately $1.0 million per year associated with the assets acquired in the Shell acquisition. Although we believe that our pipeline operations are in substantial compliance with applicable regulatory requirements, these requirements increase the potential for incurring significant expenses if additional safety requirements are imposed that exceed our current pipeline control system capabilities. We will continue to refine our estimates as data from initial assessments are collected.

The DOT has adopted API 653 as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks subject to DOT jurisdiction (approximately 61% of our 22.7 million barrels). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required by 2009. We have commenced our compliance activities and, based on currently available information, we estimate that we will spend approximately $1.0 million per year in 2003 and 2004 in connection with these activities. Such amounts incorporate the costs associated with the assets acquired in the Shell acquisition. We will continue to refine our estimates as data from initial assessments are collected.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we operate.

In the wake of the September 11, 2001 terrorist attacks on the United States, the DOT has developed a security guidance document and has issued a security circular that defines critical pipeline facilities and appropriate countermeasures for protecting them, and explains how DOT plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the DOT, we have specifically identified certain of our facilities as DOT “critical facilities” and therefore potential terrorist targets. In compliance with DOT guidance, we are performing vulnerability analyses on such facilities. Additional security measures and procedures may be adopted or implemented upon completion of these analyses, and any such measures or procedures have the potential for increasing our costs of doing business. Regardless of the steps taken to increase security, however, we cannot assure you that our facilities will not become the subject of a terrorist attack. See “—Operational Hazards and Insurance.”

Transportation Regulation

General Interstate Regulation. Our interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines, which includes crude oil, as well as refined product and petrochemical pipelines, be just and reasonable and non-discriminatory.

State Regulation. Our intrastate pipeline transportation activities are subject to various state laws and regulations, as well as orders of regulatory bodies.

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these agencies has the power, upon application by a third party, to determine the rates we are allowed to charge for transportation on, and set other terms of access to, such pipeline. In such circumstances, if the relevant regulatory agency determines that the applicable terms and conditions of service are not just and reasonable, the agency can amend the offending provisions of an existing transportation contract.

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992, which among other things, required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing several orders, including Order No. 561. Beginning January 1, 1995, Order No. 561 enables petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline’s increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline’s filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. The Energy Policy Act deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of the Energy Policy Act or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable under the Interstate Commerce Act. Generally, complaints against such “grandfathered” rates may only be pursued if the complainant can show either that a substantial change in the economic circumstances or the nature of the services has occurred since enactment or that a provision of the tariff is unduly discriminatory or preferential.

In a proceeding involving Lakehead Pipe Line Company, Limited Partnership (Opinion No. 397), the FERC concluded that there should not be a corporate income tax allowance built into a petroleum pipeline's rates to reflect income attributable to noncorporate partners because noncorporate partners, unlike corporate partners, do not pay a corporate income tax. On January 13, 1999, the FERC issued Opinion No. 435 in a proceeding involving SFPP, L.P., which, among other things, affirmed Opinion No. 397's determination that there should not be a corporate income tax allowance built into a petroleum pipeline's rates to reflect income attributable to noncorporate partners. Additionally, on rehearing of Opinion No. 397, the FERC affirmed its position regarding appropriate income tax allowance. Petitions for review of Opinion No. 435 and subsequent FERC opinions in that case are before the D.C. Circuit Court of Appeals, but some issues are being held in abeyance pending FERC action on certain requests. Once the rehearing process is completed, the FERC's position on the income tax allowance and on other rate issues could be subject to judicial review.

Our Pipelines. The FERC generally has not investigated rates on its own initiative when those rates have not been the subject of a protest or complaint by a shipper. Substantially all of our gross margins on transportation are produced by rates that are either grandfathered or set by agreement of the parties. Rates for OCS crude are set by transportation agreements with shippers that do not expire until 2007 and provide for a minimum tariff with the potential for annual escalation. The FERC has twice approved the agreed OCS rates, although application of the indexing method would have required their reduction. When these OCS agreements expire in 2007, they will be subject to renegotiation or to any of the other methods for establishing rates under Order No. 561. As a result, we believe that the rates now in effect can be sustained, although no assurance can be given that the rates currently charged would ultimately be upheld if challenged.

Trucking Regulation

We operate a fleet of trucks to transport crude oil and oilfield materials as a private, contract and common carrier. We are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the Department of Transportation. The trucking regulations cover, among other things, driver operations, maintaining log books, truck manifest preparations, the placement of safety placards on the trucks and trailer vehicles, drug and alcohol testing, safety of operation and equipment, and many other aspects of truck operations. We are also subject to the Occupational Safety and Health Act, as amended ("OSHA"), with respect to our trucking operations.

Our trucking assets in Canada are subject to regulation by provincial agencies in the provinces in which they are operated. These regulatory agencies do not set freight rates, but do establish and administer rules and regulations relating to other matters including equipment and driver licensing, equipment inspection, hazardous materials and safety.

Cross-Border Regulation

As a result of our Canadian acquisitions and cross-border activities, we are subject to regulatory matters including export licenses, tariffs, Canadian and U.S. customs and tax issues and toxic substance certifications. Regulations include the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these license, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties. Furthermore, the failure to comply with U.S., Canadian, state and local tax requirements could lead to the imposition of additional taxes, interest and penalties.

Environmental, Health and Safety Regulation

General

Numerous federal, state and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect our operations and costs. In particular, our activities in connection with storage and transportation of crude oil and other liquid hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and wastes are subject to stringent environmental laws and regulations. As with the industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Although these regulations affect our capital expenditures and earnings, we believe that they do not affect our competitive position because our competitors that comply with such laws and regulations are similarly affected. Environmental laws and regulations have historically been subject to change, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of such laws and regulations on our operations. Violation of environmental laws and regulations and any associated permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions and construction bans or delays. A discharge of petroleum hydrocarbons or hazardous substances into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and claims made by neighboring landowners and other third parties for personal injury and property damage.

Water

The Oil Pollution Act, as amended (“OPA”), was enacted in 1990 and amends provisions of the Federal Water Pollution Control Act of 1972, as amended (“FWPCA”), and other statutes as they pertain to prevention and response to oil spills. The OPA subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. The OPA establishes a liability limit of $350 million for onshore facilities; however, a party cannot take advantage of this liability limit if the spill is caused by gross negligence or willful misconduct or resulted from a violation of a federal safety, construction, or operating regulation. If a party fails to report a spill or cooperate in the cleanup, the liability limits likewise do not apply. In the event of an oil spill into navigable waters, substantial liabilities could be imposed upon us. States in which we operate have also enacted similar laws. Regulations have been or are currently being developed under OPA and state laws that may also impose additional regulatory burdens on our operations. We believe that we are in substantial compliance with applicable OPA requirements.

The FWPCA imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA imposes substantial potential liability for the costs of removal, remediation and damages. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

Some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in substantial compliance with these state requirements.

Air Emissions

Our operations are subject to the Federal Clean Air Act, as amended, and comparable state, local and provincial statutes. We believe that our operations are in substantial compliance with these statutes in all areas in which we operate.

Amendments to the Federal Clean Air Act enacted in 1990 (the “1990 Federal Clean Air Act Amendments”) as well as recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional non-attainment areas require or will require most industrial operations in the U.S. to incur capital expenditures in order to meet air emission control standards developed by the U.S. Environmental Protection Agency (the "EPA") and state environmental agencies. The 1990 Federal Clean Air Act Amendments also imposed an operating permit requirement for major sources of air emissions ("Title V permits"), which applies to some of our facilities. We will be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with obtaining or maintaining permits and approvals addressing air emission related issues. Although we can give no assurances, we believe on-going compliance with the 1990 Federal Clean Air Act Amendments will not have a material adverse effect on our financial condition or results of operations.

Solid Waste

We generate wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA is considering the adoption of stricter disposal standards for non-hazardous wastes, including oil and gas wastes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. However, it is possible that additional wastes, which could include wastes generated by our operations that are currently classified as non-hazardous wastes, will in the future be designated as "hazardous wastes." Hazardous wastes are subject to more rigorous and costly disposal requirements than are non-hazardous wastes. Such changes in the regulations could result in additional capital expenditures or operating expenses for us as well as the industry in general.

Hazardous Substances

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site or sites where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we may generate waste that falls within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such hazardous substances have been disposed of or released into the environment.

We currently own or lease, and have in the past owned or leased, properties where hydrocarbons are being or have been handled. Although we have utilized operating and disposal practices that were standard in the industry at the time, waste hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. We are currently involved in remediation activities at a number of sites, which involve potentially significant expense. See "—Environmental Remediation."

OSHA

We are subject to the requirements of OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

Endangered Species Act

The federal Endangered Species Act, as amended ("ESA"), restricts activities that may affect endangered species or their habitats. Although certain of our facilities are in areas that may be designated as habitat for endangered species, we believe that we are in substantial compliance with the ESA. However, the discovery of previously unidentified endangered species could cause us to incur additional costs or operation restrictions or bans in the affected area.

Hazardous Materials Transportation Requirements

The DOT regulations affecting pipeline safety require pipeline operators to implement measures designed to reduce the environmental impact of oil discharge from onshore oil pipelines. These regulations require operators to maintain comprehensive spill response plans, including extensive spill response training for pipeline personnel. In addition, DOT regulations contain detailed specifications for pipeline operation and maintenance. We believe our operations are in substantial compliance with such regulations. See "—Regulation—Pipeline and Storage Regulation."

Environmental Remediation

In connection with our acquisition of Scurlock Permian, we identified a number of areas of potential environmental exposure. Under the terms of our acquisition agreement, Marathon Ashland is fully indemnifying us for areas of environmental exposure which were identified at the time of the acquisition, including any and all liabilities associated with two Superfund sites at which it is alleged Scurlock Permian deposited waste oils as well as any potential liability for hydrocarbon soil and water contamination at a number of Scurlock Permian facilities. For environmental liabilities which were not identified at the time of the acquisition but which occurred prior to the closing, we have agreed to pay the costs relating to matters that are under $25,000. Our liabilities relating to matters discovered prior to May 2003 and that exceed $25,000, is currently limited to an aggregate of $1.0 million, with Marathon Ashland indemnifying us for any excess amounts. Marathon Ashland's indemnification obligations for identified sites extend indefinitely while its obligations for non-identified sites extend to matters discovered within four years of the date of acquisition (May 12, 1999) of Scurlock Permian.

In connection with our acquisition of Murphy Oil Company Ltd.'s midstream operations in Canada, we identified a limited number of environmental deficiencies during due diligence. Under the terms of our acquisition agreement, Murphy, at its sole cost and expense, agreed to remediate (to the minimum standards required by applicable environmental law) the identified environmental deficiencies. For environmental deficiencies that were not identified at the time of acquisition, but which occurred prior to closing, and were identified to Murphy prior to January 31, 2002, we have agreed to be responsible up to an aggregate amount of $300,000. Thereafter, Murphy Oil Company Ltd., agreed to remain solely responsible for the costs to remediate that exceed $20,000 for each environmental deficiency for a total of not more than ten (10) environmental deficiencies as chosen by us. Except for the environmental deficiencies identified at the time of acquisition, Murphy's maximum liability for environmental deficiencies identified post-acquisition cannot exceed $2.25 million.

In connection with our acquisition of the West Texas Gathering System, we agreed to be responsible for pre-acquisition environmental liabilities up to an aggregate amount of $1.0 million, while Chevron Pipe Line Company agreed to remain solely responsible for liabilities discovered prior to July 2002 that exceed this $1.0 million threshold.

Based on our investigations of the assets acquired from Marathon Ashland, Murphy and Chevron, we have identified several sites that exceed the threshold limitations under the various indemnities. Although we have not yet determined the total cost of remediation of these sites, we believe our indemnification arrangements should prevent such costs from having a material adverse effect on our financial condition, results of operations or cash flows.

In connection with the Shell Acquisition in 2002, Shell purchased an environmental insurance policy covering known and unknown environmental matters under which we are a named beneficiary. The policy has a $100,000 deductible per site and an aggregate coverage limit of $70 million and expires in 2012.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover releases that were previously unidentified. Although we maintain an extensive inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any future environmental releases from our assets may substantially affect our business.

Operational Hazards and Insurance

A pipeline, terminal or other facilities may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers all of our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. The events of September 11, 2001, and their overall effect on the insurance industry have adversely impacted the availability and cost of coverage. Due to these events, insurers have excluded acts of terrorism and sabotage from our insurance policies. On certain of our key assets, we have purchased a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets (including our nation’s pipeline infrastructure) may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. The DOT has developed a security guidance document and has issued a security circular that defines critical pipeline facilities and appropriate countermeasures for protecting them, and explains how DOT plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the DOT, we have specifically identified certain of our facilities as DOT “critical facilities” and therefore potential terrorist targets. In compliance with DOT guidance, we are performing vulnerability analyses on such facilities. Upon completion of such analyses, we will institute as appropriate any indicated security measures or procedures that are not already in place. We cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

Title to Properties and Rights-of-Way

We believe that we have satisfactory title to all of our assets. Although title to such properties are subject to encumbrances in certain cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens and minor easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or us, we believe that none of these burdens will materially detract from the value of such properties or from our interest therein or will materially interfere with their use in the operation of our business.

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property and, in some instances, such rights-of-way are revocable at the election of the grantor. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of majority interests have been obtained. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor’s election. In some cases, property for pipeline purposes was purchased in fee. All of the pump stations are located on property owned in fee or property under long-term leases. In certain states and under certain circumstances, we have the right of eminent domain to acquire rights-of-way and lands necessary for our common carrier pipelines.

Some of the leases, easements, rights-of-way, permits and licenses transferred to us, upon our formation in 1998 and in connection with acquisitions we have made since that time, required the consent of the grantor to transfer such rights, which in certain instances is a governmental entity. We believe that we have obtained such third party consents, permits and authorizations as are sufficient for the transfer to us of the assets necessary for us to operate our business in all material respects as described in this report. With respect to any consents, permits or authorizations that have not yet been obtained, we believe that such consents, permits or authorizations will be obtained within a reasonable period, or that the failure to obtain such consents, permits or authorizations will have no material adverse effect on the operation of our business.

Employees

To carry out our operations, our general partner or its affiliates employed approximately 1,200 employees at December 31, 2002. None of the employees of our general partner were represented by labor unions, and our general partner considers its employee relations to be good.

Summary of Tax Considerations

The tax consequences of ownership of common units depends in part on the owner’s individual tax circumstances. However, the following is a brief summary of material tax consequences of owning and disposing of common units.

Partnership Status; Cash Distributions

We are classified for federal income tax purposes as a partnership based upon our meeting certain requirements imposed by the Internal Revenue Code (the "Code"), which we must meet each year. The owners of common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we pay no federal income taxes, and a common unitholder is required to report on the unitholder's federal income tax return the unitholder's share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and to the extent that, they exceed the tax basis in the common units held.

Partnership Allocations

In general, our income and loss is allocated to the general partner and the unitholders for each taxable year in accordance with their respective percentage interests in the Partnership (including, with respect to the general partner, its incentive distribution right), as determined annually and prorated on a monthly basis and subsequently apportioned among the general partner and the unitholders of record as of the opening of the first business day of the month to which they relate, even though unitholders may dispose of their units during the month in question. A unitholder is required to take into account, in determining federal income tax liability, the unitholder's share of income generated by us for each taxable year of the Partnership ending within or with the unitholder's taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder's share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us. At any time distributions are made on the common units in excess of distributions on the subordinated units, or incentive distributions are made to the general partner, gross income will be allocated to the recipient to the extent of those distributions.

Basis of Common Units

A unitholder's initial tax basis for a common unit is generally the amount paid for the common unit. A unitholder's basis is generally increased by the unitholder's share of our income and decreased, but not below zero, by the unitholder's share of our losses and distributions.

Limitations on Deductibility of Partnership Losses

In the case of taxpayers subject to the passive loss rules (generally, individuals and closely held corporations), any partnership losses are only available to offset future income generated by us and cannot be used to offset income from other activities, including passive activities or investments. Any losses unused by virtue of the passive loss rules may be fully deducted if the unitholder disposes of all of the unitholder's common units in a taxable transaction with an unrelated party.

Section 754 Election

We have made the election provided for by Section 754 of the Code, which will generally result in a unitholder being allocated income and deductions calculated by reference to the portion of the unitholder's purchase price attributable to each asset of the Partnership.

Disposition of Common Units

A unitholder who sells common units will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis of those common units. A unitholder may not be able to trace basis to particular common units for this purpose. Thus, distributions of cash from us to a unitholder in excess of the income allocated to the unitholder will, in effect, become taxable income if the unitholder sells the common units at a price greater than the unitholder's adjusted tax basis even if the price is less than the unitholder's original cost. Moreover, a portion of the amount realized (whether or not representing gain) will be ordinary income.

Foreign, State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as foreign, state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we do business or own property. We own property and conduct business in five provinces in Canada as well as in most states in the United States. All but four of those states and all of the provinces currently impose a personal income tax that would generally require a unitholder to file a return and pay taxes in that state or province, as well as in Canada. Of the states in which we primarily do business, only Texas does not have a personal income tax. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder. Withholding, the amount of which may be more or less than a particular unitholder's income tax liability owed to the state, may not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

It is the responsibility of each prospective unitholder to investigate the legal and tax consequences, under the laws of Canada and those states and localities, of the unitholder's investment in us. Further, it is the responsibility of each unitholder to file all U.S. federal, Canadian, state, provincial and local tax returns that may be required of the unitholder.

Ownership of Common Units by Tax-Exempt Organizations and Certain Other Investors

An investment in common units by tax-exempt organizations (including IRAs and other retirement plans), regulated investment companies (mutual funds) and foreign persons raises issues unique to such persons. Virtually all of our income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. Furthermore, no significant amount of our gross income is qualifying income for purposes of determining whether a unitholder will qualify as a regulated investment company, and a unitholder who is a nonresident alien, foreign corporation or other foreign person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder's share of our taxable income. Finally, distributions to foreign unitholders are subject to federal income tax withholding.

Tax Shelter Registration

The Code generally requires that "tax shelters" be registered with the Secretary of the Treasury. We are registered as a tax shelter with the Secretary of the Treasury. Our tax shelter registration number is 99061000009. Issuance of the registration number does not indicate that an investment in the Partnership or the claimed tax benefits have been reviewed, examined or approved by the Internal Revenue Service.

Unauthorized Trading Loss

Background

In November 1999, we discovered that a former employee had engaged in unauthorized trading activity, resulting in losses of approximately $174.0 million, which includes associated costs and legal expenses. A full investigation into the unauthorized trading activities by outside legal counsel and independent accountants and consultants determined that the vast majority of the losses occurred from March through November 1999, and the impact warranted a restatement of previously reported financial information for 1999 and 1998. Approximately $7.1 million of the unauthorized trading losses was recognized in 1998 and the remainder in 1999. In 2000, we recognized an additional $7.0 million charge for settlement of litigation related to the unauthorized trading losses.

Normally, as we purchase crude oil, we establish a margin by selling crude oil for physical delivery to third parties, or by entering into future delivery obligations with respect to futures contracts. The employee in question violated our policy of maintaining a substantially balanced position between purchases and sales (or future delivery obligations) by negotiating one side of a transaction without negotiating the other, leaving the position “open.” The trader concealed his activities by hiding open trading positions, by rolling open positions forward using off-market, inter-month transactions, and by providing to counter-parties forged documents that purported to authorize such transactions. An “inter-month” transaction is one in which the receipt and delivery of crude oil are scheduled in different months. An “off-market” transaction is one in which the price is higher or lower than the prices available in the market on the day of the transaction. By matching one side of an inter-month transaction with an open position, and using off-market pricing to match the pricing of the open position, the trader could present documentation showing both a purchase and a sale, creating the impression of compliance with our policy. The offsetting side of the inter-month transaction became a new, hidden open position.

Investigation; Enhancement of Procedures

Upon discovery of the violation and related losses, we engaged an outside law firm to lead the investigation of the unauthorized trading activities. The law firm retained specialists from an independent accounting firm to assist in the investigation. In parallel effort with the investigation mentioned above, the role of the accounting firm specialists was expanded to include reviewing and making recommendations for enhancement of our systems, policies and procedures. As a result, we have developed and adopted a written policy document and manual of procedures designed to enhance our processes and procedures and improve our ability to detect any activity that might occur at an early stage. See “—Gathering, Marketing, Terminalling and Storage Operations—Crude Oil Volatility; Counter-Cyclical Balance; Risk Management.”

To specifically address the methods used by the trader to conceal the unauthorized trading, in January 2000, we sent a notice to each of our material counter-parties that no person at Plains All American Pipeline, L.P. was authorized to enter into off-market transactions. In addition, we have taken the following actions:

- We have communicated our hedging and trading strategies and risk tolerance to our traders by more clearly and specifically defining approved strategies and risk limits in our written procedures.
- Our procedures include (i) more comprehensive and frequent reporting that will allow our officers to evaluate risk positions in greater detail, and (ii) enhanced procedures to check compliance with these reporting requirements and to confirm that trading activity was conducted within guidelines.
- The procedures provide a system to educate each employee who is involved, directly or indirectly, in our crude oil transaction activities with respect to policies and procedures, and impose an obligation to notify the Risk Manager directly of any questionable transactions or failure of others to adhere to the policies, practices and procedures.
- Finally, following notification to each of our material counter-parties that off-market trading is against our policy and that any written evidence to the contrary is unauthorized and false, the Risk Manager and our other representatives have communicated our policies and enhanced procedures to our counter- parties to advise them of the information we will routinely require from them to assure timely recording and confirmation of trades.

We can give no assurance that the above steps will serve to detect and prevent all violations of our trading policy; however, we believe that such steps substantially reduce the possibility of a recurrence of unauthorized trading activities, and that any unauthorized trading that does occur would be detected before any material loss could develop.

Effects of the Loss

The unauthorized trading and associated losses resulted in a default of certain covenants under our then-existing credit facilities and significant short-term cash and letter of credit requirements.

In December 1999, we executed amended credit facilities and obtained default waivers from all of our lenders. We paid approximately $13.7 million to our lenders in connection with the amended credit facilities. In connection with the amendments, our former general partner loaned us approximately $114.0 million.

On May 8, 2000, we entered into new credit agreements to refinance our existing debt and repay the $114.0 million owed to our former general partner. The new credit agreements also provided us with additional flexibility for working capital, capital expenditures and other general corporate purposes. At closing, we had $256.0 million outstanding under a senior secured revolving credit facility. We also had at closing letters of credit of approximately $173.8 million and borrowings of approximately $20.3 million outstanding under a separate senior secured letter of credit and borrowing facility. We have since refinanced the credit facilities we entered into on May 8, 2000. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities and Long-term Debt.”

In the period immediately following the disclosure of the unauthorized trading losses, a significant number of our suppliers and trading partners reduced or eliminated the open credit previously extended to us. Consequently, the amount of letters of credit we needed to support the level of our crude oil purchases then in effect increased significantly. In addition, the cost of letters of credit increased under our credit facility. Some of our purchase contracts were terminated. We believe that by the year 2001, the effects of the loss on our cost of credit and operations were minimal and the requirement for us to issue letters of credit was reduced to levels lower than existed before the unauthorized trading loss.

After the public announcement of the trading losses, class action lawsuits were filed against us and Plains Resources. Derivative lawsuits were also filed. All of the cases have been settled and paid.

Available Information

We make available free of charge on our website (www.paalp.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file the material with, or furnish it to, the SEC.

Item 3. *Legal Proceedings*

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the short supply controls of the Export Administration Regulations (“EAR”) and must be licensed by the Bureau of Industry and Security (the “BIS”) of the U.S. Department of Commerce. We have determined that we may have exceeded the quantity of crude oil exports authorized by previous licenses. Export of crude oil in excess of the authorized amounts is a violation of the EAR. On October 18, 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and have received a new license allowing for exports of volumes more than adequately reflecting our anticipated needs. At this time, we have received no indication whether the BIS intends to charge us with a violation of the EAR or, if so, what penalties would be assessed. As a result, we cannot estimate the ultimate impact of these potential violations.

Other. We, in the ordinary course of business, are a claimant and/or a defendant in various other legal proceedings. We do not believe that the outcome of these other legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Item 4. *Submission of Matters to a Vote of Security Holders*

No matters were submitted to a vote of the security holders, through solicitation of proxies or otherwise, during the fiscal year covered by this report.

PART II

Item 5. *Market For the Registrant's Common Units and Related Unitholder Matters*

The common units, excluding the Class B common units, are listed and traded on the New York Stock Exchange under the symbol "PAA". On February 21, 2003, the market price for the common units was $25.40 per unit and there were approximately 17,126 record holders and beneficial owners (held in street name).

The following table sets forth high and low sales prices for the common units and the cash distributions paid per common unit for the periods indicated:

	Common Unit Price Range		
	High	Low	Cash Distributions
2001			
1st Quarter	$ 23.63	$ 19.06	$ 0.4750
2nd Quarter	28.00	22.15	0.5000
3rd Quarter	29.65	23.10	0.5125
4th Quarter	28.00	24.35	0.5125
2002			
1st Quarter	$ 26.79	$ 23.60	$ 0.5250
2nd Quarter	27.30	24.60	0.5375
3rd Quarter	26.38	19.54	0.5375
4th Quarter	24.44	22.04	0.5375

The Class B common units are pari passu with common units with respect to quarterly distributions, and are convertible into common units upon approval of a majority of the common unitholders. The Class B unitholders may request that we call a meeting of common unitholders to consider approval of the conversion of Class B units into common units. If the approval of a conversion by the common unitholders is not obtained within 120 days of a request, each Class B unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, the Class B units have the same voting rights as the common units. As of February 21, 2003, there was one Class B unitholder. We have also issued and outstanding 10,029,619 subordinated units, for which there is no established public trading market.

Cash Distribution Policy

We distribute on a quarterly basis all of our available cash. Available cash generally means, for any of our fiscal quarters, all cash on hand at the end of the quarter less the amount of cash reserves that is necessary or appropriate in the reasonable discretion of our general partner to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to unitholders and our general partner for any one or more of the next four quarters.

Minimum quarterly distributions are $0.45 for each full fiscal quarter. Distributions of available cash to the holders of subordinated units are subject to the prior rights of the holders of common units to receive the minimum quarterly distributions for each quarter during the subordination period, and to receive any arrearages in the distribution of minimum quarterly distributions on the common units for prior quarters during the subordination period. In addition to distributions on its 2% general partner interest, our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit. See Item 13. “Certain Relationships and Related Transactions—Our General Partner.”

Under the terms of our credit facility agreements, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities and Long-term Debt.”

Conversion of Subordinated Units

The subordination period will end if certain financial tests contained in the partnership agreement are met for three consecutive four-quarter periods (the “testing period”), but no sooner than December 31, 2003. During the first quarter after the end of the subordination period, all of the subordinated units will convert into common units. Early conversion of a portion of the subordinated units may occur if the testing period is satisfied before December 31, 2003. We are now in the testing period and, if we continue to meet the requirements, 25% of the subordinated units will convert into common units in the fourth quarter of 2003 and the remainder will convert in the first quarter of 2004. Our ability to meet these requirements is subject to a number of economic and operational contingencies. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors Related to Our Business” and “Forward Looking Statements” at the beginning of this report.

Item 6. *Selected Financial and Operating Data*

The historical financial information below for Plains All American Pipeline, L.P. was derived from our audited consolidated financial statements as of December 31, 2002, 2001, 2000, 1999 and 1998, and for the years ended December 31, 2002, 2001, 2000 and 1999 and for the period from November 23, 1998, through December 31, 1998. The financial information below for our predecessor was derived from the audited combined financial statements of our predecessor, for the period from January 1, 1998, through November 22, 1998, including the notes thereto. The operating data for all periods is derived from our records as well as those of our predecessor. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, included elsewhere in this report, and Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

“EBITDA” means earnings before interest expense, income taxes, depreciation and amortization. Adjusted EBITDA excludes the impact of unusual and non-recurring items and the impact of Statement of Financial Accounting Standards (“SFAS”) No. 133, “Accounting for Derivative Instruments and Hedging Activities.” Adjusted EBITDA is not presented in accordance with generally accepted accounting principles and is not intended to be used in lieu of GAAP presentations of results of operations or cash provided by operating activities. Adjusted EBITDA is presented because we believe it provides additional information with respect to our ability to meet our future debt service, capital expenditures and working capital requirements, and is commonly used by debt holders to analyze company performance. When evaluating Adjusted EBITDA, investors should consider, among other factors:

- increasing or decreasing trends in Adjusted EBITDA;
- whether Adjusted EBITDA has remained at positive levels historically; and
- how Adjusted EBITDA compares to levels of interest expense and long-term debt.

However, Adjusted EBITDA does not necessarily indicate whether cash flow will be sufficient for such items as working capital requirements, capital expenditures or to react to changes in our industry or the economy in general, as certain functional or legal requirements of our business may require us to use our available funds for other purposes. These measures may not be comparable to measures of other companies.

	Year Ended December 31,					Predecessor
	2002	2001	2000	1999	November 23 to December 31, 1998	January 1 to November 22, 1998
	(in millions except per unit data)					
Statement of Operations Data:						
Revenues	$8,384.2	$6,868.2	$6,641.2	$ 10,910.4	$ 398.9	$ 3,118.4
Cost of sales and operations	8,209.9	6,720.9	6,506.5	10,800.1	391.4	3,087.4
Unauthorized trading losses and related expenses	—	—	7.0	166.4	2.4	4.7
Inventory valuation adjustment	—	5.0	—	—	—	—
Gross margin	174.3	142.3	127.7	(56.1)	5.1	26.3
General and administrative expenses	45.7	46.6	40.8	23.2	0.8	4.5
Depreciation and amortization	34.0	24.3	24.5	17.3	1.2	4.2
Restructuring expense	—	—	—	1.4	—	—
Total expenses	79.7	70.9	65.3	41.9	2.0	8.7
Operating income (loss)	94.6	71.4	62.4	(98.0)	3.1	17.6
Interest expense	(29.1)	(29.1)	(28.7)	(21.1)	(1.4)	(11.3)
Gain on sale of assets	—	1.0	48.2	16.4	—	—
Interest and other income (loss)	(0.2)	0.4	10.8	0.9	0.1	0.6
Income (loss) before provision in lieu of income taxes, extraordinary item and cumulative effect of accounting change	65.3	43.7	92.7	(101.8)	1.8	6.9
Provision in lieu of income taxes	—	—	—	—	—	2.6
Income (loss) before extraordinary item and cumulative effect of accounting change	$ 65.3	$ 43.7	$ 92.7	(101.8)	$ 1.8	$ 4.3
Basic and diluted net income (loss) per limited partner unit before extraordinary item and cumulative effect of accounting change	$ 1.34	$ 1.12	$ 2.64	$ (3.16)	$ 0.06	$ 0.25
Weighted average number of limited partner units outstanding	45.5	37.5	34.4	31.6	30.1	17.0
Balance Sheet Data:						
(at end of period):						
Working capital[1]	$ (34.3)	$ 52.9	$ 47.1	$ 101.5	$ 2.2	N/A
Total assets	1,666.6	1,261.2	885.8	1,223.0	607.2	N/A
Related party debt—Long-term	—	—	—	114.0	—	N/A
Long-term debt[2]	509.7	354.7	320.0	310.1	175.0	N/A
Partners' capital	511.6	402.8	214.0	193.0	270.5	N/A
Other Data:						
Adjusted EBITDA[3]	$ 130.4	$ 109.6	$ 103.0	$ 89.1	$ 6.7	$ 27.0
Maintenance capital expenditures	6.0	3.4	1.8	1.7	0.2	1.5
Net cash provided by (used in) operating activities	173.9	(30.0)	(33.5)	(71.2)	7.2	21.4
Net cash provided by (used in) investing activities	(363.8)	(249.5)	211.0	(186.1)	(3.1)	(399.6)
Net cash provided by (used in) financing activities	189.5	279.5	(227.8)	305.6	1.4	386.2

(Table continued on following page)

	Year Ended December 31,					Predecessor
	2002	2001	2000	1999	November 23 to December 31, 1998	January 1 to November 22, 1998
				(in thousands)		
Operating Data:						
Volumes (barrels per day):						
Pipeline segment:						
Tariff activities						
All American	65	69	74	103	110	114
Basin	93	N/A	N/A	N/A	N/A	N/A
Other domestic	228	144	130	61	—	—
Canada	187	132	N/A	N/A	N/A	N/A
Margin activities	73	61	60	54	51	49
Total	646	406	264	218	161	163
Gathering, marketing, terminalling and storage segment:						
Lease gathering	410	348	262	265	126	87
Bulk purchases	80	46	28	138	134	95
Total	490	394	290	403	260	182
Cushing terminal throughput	110	94	59	72	62	81

(1) At December 31, 1999, working capital included $37.9 million of pipeline linefill and $103.6 million for a segment of the All American Pipeline, both of which were sold in the first quarter of 2000.

(2) Includes current maturities of long-term debt of $9.0 million, $3.0 million, $0.0 million, $50.7 million and $0.0 million at December 31, 2002, 2001, 2000, 1999 and 1998, respectively. In addition, long-term debt in 1999 excludes related party debt.

(3) For the year ended December 31, 2002, Adjusted EBITDA excludes the impact of:

- noncash reserve for potential environmental obligations of $1.2 million;
- noncash SFAS 133 gain of $0.3 million; and
- write-off of deferred acquisition-related costs of $1.0 million.

For the year ended December 31, 2001, Adjusted EBITDA excludes the impact of:

- noncash reserve for receivables of $3.0 million;
- noncash cumulative effect of accounting change gain of $0.5 million;
- noncash SFAS 133 gain of $0.2 million;
- noncash compensation expense of $5.7 million;
- gain on sale of assets of $1.0 million; and
- noncash mark-to-market inventory charge of $5.0 million.

For the year ended December 31, 2000, Adjusted EBITDA excludes the impact of:

- extraordinary loss on early extinguishment of debt of $15.1 million;
- unauthorized trading losses and related expenses of $7.0 million;
- noncash reserve for receivables of $5.0 million;
- noncash compensation expense of $3.1 million;
- gain on sale of assets of $48.2 million; and
- gain on interest rate swap of $9.7 million.

For the year ended December 31, 1999, Adjusted EBITDA excludes the impact of:

- unauthorized trading losses and related expenses of $166.4 million;
- restructuring expense of $1.4 million;
- noncash compensation expense of $1.0 million;
- gain on sale of assets of $16.4 million; and
- extraordinary loss on early extinguishment of debt of $1.5 million.

For the period from November 23 to December 31, 1998, Adjusted EBITDA excludes the impact of:

- Unauthorized trading losses and related expenses of $2.4 million.

For the period from January 1 to November 22, 1998, Adjusted EBITDA excludes the impact of:

- Unauthorized trading losses and related expenses of $4.7 million.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion of our financial condition and results of our operations should be read in conjunction with our historical consolidated financial statements and accompanying notes. For more detailed information regarding the basis of presentation for the following financial information, see the "Notes to the Consolidated Financial Statements."

Overview

Plains All American Pipeline, L.P. is a Delaware limited partnership (the "Partnership") formed in September of 1998. On November 23, 1998, we completed our initial public offering ("IPO") and the transactions whereby we became the successor to the midstream crude oil business and assets of Plains Resources Inc. and its wholly owned subsidiaries ("Plains Resources"). Immediately after our IPO, Plains Resources Inc. owned 100% of our general partner interest and an overall effective ownership in the Partnership of 57% (including its 2% general partner interest and common and subordinated units owned). As discussed below, Plains Resources' effective ownership interest in the Partnership has been reduced substantially.

In May 2001, senior management and a group of financial investors entered into a transaction with Plains Resources to acquire majority control of our general partner and a majority of the outstanding subordinated units. The transaction closed in June 2001 and, for purposes of this report, is referred to as the "General Partner Transition." As a result of this transaction and subsequent equity offerings, Plains Resources' overall effective ownership has been reduced to approximately 25%. See Item 12. "Security Ownership of Certain Beneficial Owners and Management." In addition, certain officers of the general partner who previously were also officers of Plains Resources terminated their affiliation with Plains Resources and as a result now devote 100% of their efforts to the management of the Partnership.

Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., All American Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil pipeline transportation as well as gathering, marketing, terminalling and storage of crude oil and liquefied petroleum gas ("LPG"). We own an extensive network in the United States and Canada of pipeline transportation, storage and gathering assets in key oil producing basins and at major market hubs. Our operations are conducted primarily in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan and consist of two operating segments: (i) Pipeline Operations and (ii) Gathering, Marketing, Terminalling and Storage Operations. Our operating segments are discussed further in the "Results of Operations" section below.

Acquisitions

We completed a number of acquisitions in 2002 and 2001 that have impacted the results of operations and liquidity discussed herein. The following acquisitions were accounted for, and the purchase price was allocated, in accordance with the purchase method of accounting. We adopted Statement of Financial Accounting Standards ("SFAS") No. 141, "Business Combinations" in 2001 and followed the provisions of that statement for all business combinations initiated after June 30, 2001. Our ongoing acquisition activity is discussed further in "Liquidity and Capital Resources" below.

Shell West Texas Assets

On August 1, 2002, we acquired interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas from Shell Pipeline Company LP and Equilon Enterprises LLC (the "Shell acquisition"). The primary assets included in the transaction are interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. The total purchase price of $324.4 million consisted of (i) $304.0 million in cash, which was borrowed under our revolving credit facility,

(ii) approximately $9.1 million related to the settlement of pre-existing accounts receivable and inventory balances and (iii) approximately $11.3 million of estimated transaction and closing costs. The entire purchase price was allocated to property and equipment. We are in the process of evaluating certain estimates made in the purchase price allocation, including costs associated with the shutdown of the Rancho Pipeline System; thus the allocation is subject to refinement.

The acquired assets are primarily fee-based mainline crude oil pipeline transportation assets that gather crude oil in the Permian Basin and transport the crude oil to major market locations in the Mid-Continent and Gulf Coast regions. The Permian Basin has long been one of the most stable crude oil producing regions in the United States, dating back to the 1930s. The acquired assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we provide storage and terminalling services. In addition, we believe that the Basin Pipeline System is poised to benefit from potential shut-downs of refineries and other pipelines due to the shifting market dynamics in the West Texas area. The Rancho Pipeline System will be taken out of service in March 2003, pursuant to the operating agreement. See Items 1 and 2. “Business and Properties—Pipeline Operations—Pipeline Assets—Southwest U.S.—Rancho Pipeline System.”

For more information on this transaction, as well as historical financial information on the businesses acquired and pro forma financial information reflecting the acquisition of the businesses, please refer to our Form 8-K dated August 9, 2002, which was filed with the Securities and Exchange Commission.

Coast Energy Group and Lantern Petroleum

In March 2002, we completed the acquisition of substantially all of the domestic crude oil pipeline, gathering and marketing assets of Coast Energy Group and Lantern Petroleum, divisions of Cornerstone Propane Partners, L.P., for approximately $8.3 million in cash net of liabilities assumed and transaction costs (the “Cornerstone acquisition”). The principal assets acquired are located in West Texas and include several gathering lines, crude oil contracts and a small truck and trailer fleet. The acquired assets serve to expand our core market in West Texas and give us access to more volumes in the area.

Butte Pipe Line Company

In February 2002, we acquired an approximate 22% equity interest in Butte Pipe Line Company from Murphy Ventures, a subsidiary of Murphy Oil Corporation (the “Butte acquisition”). The total cost of the acquisition, including various transaction and related expenses, was approximately $7.6 million. Butte Pipe Line Company owns the 373-mile Butte Pipeline System, principally a mainline system, that runs from Baker, Montana to Guernsey, Wyoming. The Butte Pipeline is connected to the Poplar Pipeline System, which in turn is connected to the Wascana Pipeline System, which is 100% wholly owned by us. We believe these pipeline systems will play an important role in moving increasing volumes of Canadian crude oil into markets in the United States.

Wapella Pipeline System

In December 2001, we consummated the acquisition of the Wapella Pipeline System from private investors for approximately $12.0 million, including transaction costs (the “Wapella acquisition”). The entire purchase price was allocated to property and equipment. The system is located in southeastern Saskatchewan and southwestern Manitoba and further expands our market in Canada. In 2001, the Wapella Pipeline System delivered approximately 11,000 barrels per day of crude oil to the Enbridge Pipeline at Cromer, Manitoba. The acquisition also includes approximately 21,500 barrels of crude oil storage capacity located along the system, as well as a truck terminal.

CANPET Energy Group

In July 2001, we acquired the assets of CANPET Energy Group Inc., a Calgary-based Canadian crude oil and LPG marketing company (the “CANPET acquisition”), for approximately $42.0 million plus excess inventory at the closing date of approximately $25.0 million. Approximately $18.0 million of the purchase price, payable in common units, was deferred subject to various performance standards being met. In addition, an amount will be paid equivalent to the distributions that would have been paid on the common units had they been outstanding since the acquisition was consummated. See Note 8 —“Partners’ Capital and Distributions” in the “Notes to the Consolidated Financial Statements.” At the time of the acquisition, CANPET’s activities consisted of gathering approximately 75,000 barrels per day of crude oil and marketing an average of approximately 26,000 barrels per day of natural gas liquids. The principal assets acquired include a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and operating inventory. The acquired assets are part of our establishment of a Canadian operation that substantially mirrors our operations in the United States. The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Inventory	$	28.1
Goodwill		11.1
Intangible assets (contracts)		1.0
Pipeline linefill		4.3
Crude oil gathering, terminalling and other assets		5.1
Total	$	49.6

Murphy Oil Company Ltd. Midstream Operations

In May 2001, we completed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately $161.0 million in cash ($158.4 million after post-closing adjustments), including financing and transaction costs (the “Murphy acquisition”). Initial financing for the acquisition was provided through borrowings under our credit facilities. The purchase price included $6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 560 miles of crude oil and condensate mainlines (including dual lines on which condensate is shipped for blending purposes and blended crude is shipped in the opposite direction) and associated gathering and lateral lines, approximately 1.1 million barrels of crude oil storage and terminalling capacity located primarily in Kerrobert, Saskatchewan, approximately 254,000 barrels of pipeline linefill and tank inventories, and 121 trailers used primarily for crude oil transportation. The acquired assets are part of our establishment of a Canadian operation that substantially mirrors our operations in the United States.

Murphy agreed to continue to transport production from fields previously delivering crude oil to these pipeline systems, under a long-term contract. At the time of acquisition, these volumes averaged approximately 11,000 barrels per day. Total volumes transported on the pipeline system in 2001 were approximately 223,000 barrels per day of light, medium and heavy crudes, as well as condensate.

The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Crude oil pipeline, gathering and terminal assets	$	148.0
Pipeline linefill		7.6
Net working capital items		2.0
Other property and equipment		0.5
Other assets, including debt issue costs		0.3
Total	$	158.4

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. The critical accounting policies that we have identified are discussed below.

Depreciation, Amortization and Impairment of Long-Lived Assets

We calculate our depreciation and amortization based on estimated useful lives and salvage values of our assets. When assets are put into service, we make estimates with respect to useful lives that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

Additionally, we assess our long-lived assets for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include changes in our business plans, a change in the extent or manner in which a long-lived asset is being used or in its physical condition, or a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge would be recorded for the excess of the carrying value of the asset over its fair value. Determination as to whether and how much an asset is impaired would necessarily involve numerous management estimates. Any impairment reviews and calculations would be based on assumptions that are consistent with our business plans and long-term investment decisions.

Allowance for Doubtful Accounts Receivable

We routinely review our receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such uncollected amounts involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered, received or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. Based on these analyses, we have established an allowance for doubtful accounts receivable and consider the reserve adequate, however, there is no assurance that actual amounts will not vary significantly from estimated amounts.

Revenue and Expense Accruals

We routinely make accruals for both revenues and expenses due to the timing of compiling billing information, receiving third party information and reconciling our records with those of third parties. In situations where we are required to make mark-to-market estimates pursuant to SFAS 133, the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. A portion of the estimates we use are based on internal models or models of third parties because they are not quoted on a national market. Additionally, values may vary among different models and may not be reflective of the price at which they can be settled due to the lack of a liquid market. We believe our estimates for these items are reasonable, but there is no assurance that actual amounts will not vary significantly from estimated amounts.

Liability and Contingency Accruals

We accrue reserves for contingent liabilities including, but not limited to, environmental remediation and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. These estimates will be increased or decreased as additional information is obtained or resolution is achieved.

Determination of Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets

In conjunction with each acquisition, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. We also estimate the amount of transaction costs that will be incurred in connection with each acquisition. As additional information becomes available, we may adjust the original estimates within a short time subsequent to the acquisition. In addition, in conjunction with the recent adoption of SFAS 141, we are required to recognize intangible assets separately from goodwill. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment. The impairment testing entails estimating future net cash flows relating to the asset, based on management's estimate of market conditions including pricing, demand, competition, operating costs and other factors. Intangible assets with finite lives are amortized over the estimated useful life determined by management. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired. We believe our estimates for these items are reasonable, but there is no assurance that actual amounts will not vary significantly from estimated amounts.

Results of Operations

Analysis of Three Years Ended December 31, 2002

Our operating results were impacted by acquisitions made during 2002 and 2001. These acquisitions include the assets acquired in the Shell acquisition, which are included in our results of operations as of August 1, 2002, and the Murphy and CANPET acquisitions, which are included in our results of operations as of April 1, 2001 and July 1, 2001, respectively.

We reported net income for the year ended December 31, 2002, of $65.3 million on total revenues of $8.4 billion compared to net income for the same period in 2001 and 2000 of $44.2 million and $77.5 million on total revenues of $6.9 billion and $6.6 billion, respectively. When we evaluate our results for performance against expectations, public guidance and trend analysis, we exclude the impact of SFAS 133 resulting from (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. The majority of these instruments serve as economic hedges which offset future physical positions not reflected in current results. Therefore, the SFAS 133 adjustment to net income is not a complete depiction of the economic substance of the transaction, as it only represents the derivative side of these transactions and does not take into account the offsetting physical position. Also, the impact will vary from quarter to quarter based on market prices at the end of the quarter. In addition, we exclude the impact of other unusual or nonrecurring items within each period.

The following table reconciles our reported net income to our net income before unusual or nonrecurring items and the impact of SFAS 133 (in millions):

	Year Ended December 31,		
	2002	2001	2000
Reported Net Income	$ 65.3	$ 44.2	$ 77.5
Write-off of deferred acquisition-related costs	1.0	—	—
Noncash reserve for potential environmental obligations	1.2	—	—
Noncash mark-to-market inventory charge	—	5.0	—
Noncash compensation expense	—	5.7	3.1
Gain on sale of assets	—	(1.0)	(48.2)
Gain on interest rate swap	—	—	(9.7)
Extraordinary loss on early extinguishment of debt	—	—	15.1
Unauthorized trading losses and related expenses	—	—	7.0
Noncash reserve for receivables	—	3.0	5.0
Noncash amortization of debt issues cost	—	—	4.6
Noncash cumulative effect of accounting change	—	(0.5)	—
Noncash SFAS 133 adjustment	(0.3)	(0.2)	—
Net Income before unusual or nonrecurring items and the impact of SFAS 133	$ 67.2	$ 56.2	$ 54.4

Our operations consist of two operating segments: (1) Pipeline Operations—engages in interstate and intrastate crude oil pipeline transportation and certain related merchant activities; and (2) Gathering, Marketing, Terminalling and Storage Operations—engages in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets. A discussion of the results of operations of each segment follows.

Pipeline Operations

We own and operate over 5,600 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee, third-party leases of pipeline capacity, barrel exchanges and buy/sell arrangements. We also use our pipelines in our merchant activities conducted under our gathering and marketing business. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The gross margin generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable costs of operating the pipeline. Gross margin from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

The following table sets forth our operating results from our Pipeline Operations segment for the periods indicated:

	Year ended December 31,		
	2002	2001	2000
Operating Results (in millions):			
Revenues (including intersegment)	$ 486.2	$ 357.4	$ 574.4
Gross margin	$ 83.9	$ 71.3	$ 51.8
General and administrative expenses(1)	13.2	12.4	12.7
Gross profit	$ 70.7	$ 58.9	$ 39.1
Average Daily Volumes (thousands of barrels per day)(2):			
Tariff activities			
All American	65	69	74
Basin	93	—	—
Other domestic	228	144	130
Canada(3)	187	132	—
Merchant margin activities	73	61	60
Total	646	406	264

(1) General and Administrative ("G&A") expenses reflect direct costs attributable to each segment and an allocation of other G&A expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A expenses by segment for 2001 and 2000 to conform to the refined presentation used in 2002. The proportional allocations by segment will continue to be based on the business activities that exist during each period.

(2) Volumes associated with acquisitions represent weighted average daily amounts during the year of acquisition.

(3) 2001 volume information has been adjusted for consistency of comparison with 2002 presentation.

As discussed above, we have completed a number of acquisitions in 2002 and 2001 that have impacted the results of operations herein. The following table adjusts our total average daily volumes for acquisitions made in each period for comparison purposes:

	Year ended December 31,		
	2002	2001	2000
		(barrels in thousands)	
Total average daily volumes(1)	646	406	264
Less volumes from:			
2002 Acquisitions(2)	(171)	—	—
2001 Acquisitions(2)(3)	(193)	(134)	—
Total adjusted average daily volumes	282	272	264

(1) Volumes associated with acquisitions represent weighted average daily amounts during the year of acquisition.

(2) The 2002 acquisitions include the Shell acquisition and Butte acquisition. The 2001 acquisitions includes the Murphy acquisition and other minor acquisitions.

(3) The increase in average daily volumes from 2001 to 2002 is primarily due to the inclusion of the Murphy acquisition for a full year in 2002 compared to only a portion of the year in 2001.

Adjusted average daily volumes transported on our pipelines increased approximately 10,000 barrels per day for the year ended December 31, 2002 as compared to the year ended December 31, 2001. The increase was primarily due to higher volumes from our merchant activities partially offset by an approximate 4,000 barrel per day decrease in our All American tariff volumes attributable to California outer continental shelf ("OCS") production and various small decreases on other domestic pipelines. Volumes from the Santa Ynez and Point Arguello fields, both offshore California, have steadily declined from 1995 through 2002. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline tariff revenues of approximately $3.1 million, based on the 2002 average tariff rate. Adjusted average daily volumes transported on our pipelines increased approximately 8,000 barrels per day for the year ended December 31, 2001 as compared to the year ended December 31, 2000. The increase was primarily related to increases in the volumes transported on the West Texas Gathering system and various other domestic pipelines partially offset by an approximate 4,500 barrel per day decrease in our All American tariff volumes attributable to California OCS production.

As discussed above, the revenues from our pipeline operations are comprised of pipeline margin revenue from our merchant activities and tariff and fee revenues from volumes transported on our pipelines. Tariffs are typically indexed to the Producer Price Index. The following table details our Pipeline Operations revenues and adjusts our tariff and fee revenue for acquisitions made in each period for comparison purposes:

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
Pipeline margin revenue	$ 382.5	$ 288.0	$ 515.6
Tariff and fee revenue	103.7	69.4	58.8
Total pipeline operations revenue	$ 486.2	$ 357.4	$ 574.4
Adjustments to tariff and fee revenue for acquisitions			
Tariff and fee revenue	$ 103.7	$ 69.4	$ 58.8
Less revenue from:			
2002 acquisitions	(23.1)	—	—
2001 acquisitions(1)	(21.6)	(9.9)	—
Total adjusted tariff and fee revenue	$ 59.0	$ 59.5	$ 58.8

(1) The increase in revenue from 2001 to 2002 is primarily due to the inclusion of the Murphy acquisition for a full year in 2002 and increases in the tariffs of certain pipeline systems acquired in the Murphy acquisition.

Pipeline margin revenues from our merchant activities were approximately $382.5 million for the year ended December 31, 2002 compared to $288.0 million and $515.6 million for the years ending December 31, 2001 and 2000, respectively. The increase in 2002 revenues over the prior year period is primarily related to our merchant activities on our San Joaquin Valley gathering system. This increase was related to both increased volumes and higher average prices on our buy/sell arrangements in the 2002 period. However, this business is a margin business and although revenues and cost of sales are impacted by the absolute level of crude oil prices, crude oil prices have a limited impact on gross margin. Similarly, the decrease in revenues from our merchant activities for the year ended December 31, 2001 from the year ended December 31, 2000 was related to our merchant activities on our San Joaquin Valley gathering system. The decrease in this period was related to lower volumes of buy/sell arrangements coupled with lower average prices on those arrangements in the 2001 period compared to the 2000 period, as well as a decrease in activity due to the sale of a segment of the All American Pipeline in March 2000. Adjusted tariff and fee revenue was relatively flat for all of the comparable periods as the decrease in volumes attributable to OCS production was offset in each period by other increases, including increases in the tariffs for OCS volumes transported.

Gross margin from pipeline operations was $83.9 million for the year ended December 31, 2002 compared to $71.3 million and $51.8 million for the years ended December 31, 2001 and 2000, respectively. The increase of approximately $12.6 million in 2002 over 2001 resulted primarily from our tariff and fee related activities and was due to the following offsetting items:

- increased volumes on our U.S. pipelines resulting from the businesses acquired during 2002
- increased volumes on our Canadian pipelines due to the inclusion of the pipelines results for the entire 2002 period compared to only a portion of 2001
- a decrease in our volumes attributable to California OCS production that was generally offset with an increase in the tariff per barrel of OCS production transported
- an increase in operating expenses to $40.1 million in the 2002 period from $19.4 million in the 2001 period.

The increase in operating expenses was primarily related to the acquisition of various businesses in 2002 and late 2001 and the inclusion of the results of the Murphy acquisition for all of 2002 compared to only a portion of 2001. Operating expense for the 2002 period also includes a $1.2 million noncash charge associated with the establishment of a liability for potential cleanup of environmental conditions associated with our 1999 acquisitions. We reassessed the previous investigations and completed environmental studies during 2002, and remediation activities are on-going. This amount is approximately equal to the threshold amounts the partnership must incur before the sellers' indemnities take effect. In many cases, the actual cash expenditures may not occur for ten years.

The increase in pipeline gross margin of $19.5 million in the 2001 period compared to the 2000 period is primarily attributable to increased margin from our tariff and fee related activities. The increase in our tariff and fee related activities were primarily due to the impact of the Canadian acquisitions. Excluding the Canadian acquisitions, gross margin from pipeline operations would have increased approximately 8%, due to slightly higher volumes and tariffs, while maintaining operating expenses at a fairly constant level.

General and administrative expense ("G&A") includes the costs directly associated with the segment, as well as a portion of corporate overhead costs considered allocable. See—"Other Income and Expenses—Unallocated G&A Expense." G&A expense related to our pipeline operations was $13.2 million for the year ended December 31, 2002 compared to $12.4 million and $12.7 million for the years ended December 31, 2001 and 2000, respectively. The increase in G&A expense of approximately $0.8 million in the 2002 period was partially due to increased costs from the assets acquired in the Canadian acquisitions due to the inclusion of those assets for the entire 2002 period compared to only a portion of 2001. G&A expense related to pipeline operations decreased approximately $0.3 million in the year ended December 31, 2001 from the year ended December 31, 2000. The decrease was primarily related to lower reserves for potentially uncollectible receivables included in G&A in the 2001 period. This decrease was partially offset by G&A expense of approximately $0.7 million from the assets acquired in the Canadian acquisition and increased personnel costs associated with the General Partner Transition.

Gathering, Marketing, Terminalling and Storage Operations

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased barrels plus the sale of additional barrels exchanged through buy/sell arrangements entered into to enhance the margins of the gathered and bulk-purchased crude oil. Gross margin from our gathering and marketing activities is dependent on our ability to sell crude oil at a price in excess of our aggregate cost. These operations are margin businesses, and are not directly affected by the absolute level of crude oil prices, but are affected by overall levels of supply and demand for crude oil and fluctuations in market-related indices. Accordingly, an increase or decrease in revenues is not necessarily an indication of segment performance.

We own and operate approximately 22.7 million barrels of above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called "terminalling." Gross margin from terminalling and storage activities is dependent on the throughput volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. We also use our storage tanks to counter-cyclically balance our gathering and marketing operations and to execute different hedging strategies to stabilize margins and reduce the negative impact of crude oil market volatility.

During periods when supply exceeds the demand for crude oil, the market for crude oil is often in contango, meaning that the price of crude oil for future deliveries is higher than current prices. A contango market has a generally negative impact on marketing margins, but is favorable to the storage business, because storage owners at major trading locations (such as the Cushing Interchange) can simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. When there is a higher demand than supply of crude oil in the near term, the market is backward, meaning that the price of crude oil for future deliveries is lower than current prices. A backwardated market has a positive impact on marketing margins because crude oil gatherers can capture a premium for prompt deliveries. In this environment, there is little incentive to store crude oil, as current prices are above future delivery prices. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow.

We establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX and over-the-counter. Through these transactions, we establish on a monthly basis a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. We purchase crude oil on both a fixed and floating price basis. As fixed price barrels are purchased, we enter into sales arrangements with refiners, trade partners or on the NYMEX, which establishes a margin and protects us against future price fluctuations. When floating price barrels are purchased, we match those contracts with similar type sales agreements with our customers, or likewise establish a hedge position using the NYMEX futures market. From time to time, we enter into arrangements that expose us to basis risk. Basis risk occurs when crude oil is purchased based on a crude oil specification and location that differs from the countervailing sales arrangement. In order to protect profits involving our physical assets and to manage risks associated with our crude purchase obligations, we use derivative instruments. Except for pre-defined inventory transactions as discussed below, our policy is only to purchase crude oil for which we have a market and to structure our sales contracts so that crude oil price fluctuations do not materially affect the gross margin which we receive. In November 1999, we discovered that this policy was violated. See Items 1 and 2. "Business and Properties—Unauthorized Trading Losses". Except for crude oil inventory transactions that do not exceed 500,000 barrels, we do not acquire and hold crude oil futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses. Similarly, while we seek to maintain a position that is substantially balanced within our LPG activities, as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions, from time to time we experience net unbalanced positions for short periods of time. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, our policies provide that any net imbalance may not exceed 200,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations.

The following table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage operations segment for the periods indicated:

	Year Ended December 31,		
	2002	2001	2000
Operating Results (in millions):			
Revenues	$ 7,921.8	$ 6,528.3	$ 6,135.5
Gross margin	$ 90.4	$ 71.0	$ 75.9
General and administrative expenses[(1)]	31.5	28.5	25.0
Gross profit	$ 58.9	$ 42.5	$ 50.9
Average Daily Volumes (thousands of barrels per day)[(2)]:			
Lease gathering	410	348	262
Bulk purchases	80	46	28
Total	490	394	290
Terminal throughput[(3)]	110	94	59
Storage leased to third parties, monthly average volumes[(3)(4)]	1,067	2,136	1,437

(1) G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A expenses by segment for all periods presented to conform to the refined presentation used in 2002. The proportional allocations by segment will continue to be based on the business activities that exist during each period.

(2) Volumes associated with acquisitions represent weighted average daily amounts during the year of acquisition.
(3) Throughput and storage amounts for Cushing facility.
(4) The level of tankage at Cushing that we allocate for our arbitrage activities (and therefore is not available for lease to third parties) varies throughout crude oil price cycles.

Average daily volumes of crude oil gathered from producers, using our assets or third-party assets, totaled approximately 410,000 barrels per day for the year ended December 31, 2002 compared to 348,000 barrels per day and 262,000 barrels per day for the years ended December 31, 2001 and 2000, respectively. Average daily volumes of crude oil purchased in bulk, primarily at major trading locations, for each of the three years in the period ending December 31, 2002, totaled approximately 80,000 barrels per day, 46,000 barrels per day and 28,000 barrels per day, respectively. Storage leased to third parties at our Cushing Terminal decreased to an average of 1.1 million barrels per month for the year ended December 31, 2002 from an average of 2.1 million barrels per month and 1.4 million barrels per month in the years ended December 31, 2001 and 2000, respectively. Average storage leased to third parties decreased during the period as we used an increased amount of our capacity for our own account due to contango market activities and our hedging strategies in the current year period. A contango market exists when oil prices for future deliveries are higher than current prices thereby making it profitable to store crude oil for future delivery. Terminal throughput volumes at our Cushing terminal averaged approximately 110,000, 94,000 and 59,000 barrels per day for the years ended December 31, 2002, 2001 and 2000, respectively.

Revenues from our gathering, marketing, terminalling and storage operations in each of the three years in the period ended December 31, 2002 totaled approximately $7.9 billion, $6.5 billion and $6.1 billion, respectively. The increase in 2002 resulted from higher average volumes from our Canadian and U.S. operations. Revenues from our Canadian operations were approximately $1.6 billion for the 2002 period compared to $0.8 billion in 2001. The increase was primarily related to the inclusion of the CANPET acquisition for all of 2002 compared to only a portion of 2001. This resulted in an increase in 2002 gathered volumes of approximately 47,000 barrels per day and bulk purchases of approximately 18,000 barrels per day over the 2001 period. The remaining increase was primarily related to higher U.S. volumes during 2002. The average NYMEX settlement price for crude oil was $26.10 per barrel in 2002 compared to $25.98 per barrel in 2001. The increase in 2001 as compared to 2000 was primarily due to the impact of the Canadian acquisitions offset by lower oil prices in the 2001 period. The average NYMEX settlement price for crude oil was $30.25 per barrel in 2000. As noted previously, revenues are also impacted by buy/sell arrangements entered into to enhance the margins of our lease gathered and bulk purchased barrels. We have not included the volumes associated with these buy/sell arrangements.

Gross margin from gathering, marketing, terminalling and storage operations totaled approximately $90.4 million in the year ended December 31, 2002 compared to approximately $71.0 million and $75.9 million in the years ended December 31, 2001 and 2000, respectively. As discussed above, we exclude the impact of SFAS 133 and other unusual or nonrecurring items when evaluating our results. The table below reconciles our reported gross margin for the segment to gross margin before unusual or nonrecurring items and the impact of SFAS 133 (“Adjusted Gross Margin”). Included in the reconciling items below is a $5.0 million noncash writedown of operating crude oil inventory in the fourth quarter of 2001 to reflect prices at December 31, 2001. See Note 2 “Summary of Significant Accounting Policies” in the “Notes to the Consolidated Financial Statements.” Additionally, in 2000, we recognized a $7.0 million charge for the settlement of litigation related to the unauthorized trading by a former employee. See Items 1 and 2. “Business and Properties—Unauthorized Trading Losses.”

	Year Ended December 31,		
	2002	2001	2000
Reported Gross Margin (in millions)	$ 90.4	$ 71.0	$ 75.9
Noncash mark-to-market inventory charge	—	5.0	—
Unauthorized trading losses and related expenses	—	—	7.0
Noncash reserve for receivables	—	2.0	—
Noncash SFAS 133 adjustment	(0.3)	(0.2)	—
Gross margin before unusual or nonrecurring items and the impact of SFAS 133 (“Adjusted Gross Margin”)	$ 90.1	$ 77.8	$ 82.9

Adjusted Gross Margin increased approximately $12.3 million in the 2002 period as compared to the 2001 period primarily due to higher average daily volumes as discussed above. The decrease in Adjusted Gross Margin in 2001 as compared to the 2000 period is primarily attributable to a relatively weak environment for gathering and marketing due to market conditions. The market conditions during 2000 were favorable for gathering and marketing margins.

G&A includes the costs directly associated with the segment, as well as a portion of corporate overhead costs considered allocable. See “—Other Income and Expenses—Unallocated G&A Expense.” G&A expense related to our gathering, marketing, terminalling and storage operations was $31.5 million for the year ended December 31, 2002 compared to $28.5 million and $25.0 million for the years ended December 31, 2001 and 2000, respectively. The increase in G&A expense of approximately $3.0 million in the 2002 period was primarily due to increased costs of $5.6 million from the assets acquired in the Canadian acquisition due to the inclusion of those assets for the entire 2002 period compared to only a portion of 2001 partially offset by decreased G&A of $2.6 million from our domestic operations. This decrease was partially related to a reduction in accounting and consulting costs in the 2002 period from those that had been incurred in the 2001 period.

G&A expense related to gathering, marketing, terminalling and storage operations increased approximately $3.5 million for the year ended December 31, 2001 from the year ended December 31, 2000. The increase was primarily related to costs of approximately $4.0 million from the assets acquired in the Canadian acquisition and increased personnel costs associated with the General Partner Transition partially offset by lower reserves for potentially uncollectible receivables included in G&A in the 2001 period.

Other Income and Expenses

Unallocated G&A Expenses. Total G&A expenses were $45.7 million, $46.6 million and $40.8 million for the years ended December 31, 2002, 2001 and 2000, respectively. We have included in the above segment discussion the G&A expense for each of these years that were attributable to our segments. During 2002, we incurred charges that were not attributable to a segment of $1.0 million related to the write-off of deferred acquisition-related costs. See “—Outlook—Ongoing Acquisition Activities.” During 2001 and 2000, we incurred charges that were not attributable to a segment of $5.7 million and $3.1 million, respectively, related to incentive compensation paid to certain officers and key employees of Plains Resources and its affiliates. In 1998 (in connection with our IPO) and 2000, Plains Resources granted certain officers and key employees of the former general partner the right to earn ownership in a portion of our common units owned by it. These rights provided for a three-year vesting period, subject to distributions being paid on the common and subordinated units. In connection with the General Partner Transition in 2001, certain equity interests previously granted to management and outside directors vested, resulting in a charge to our 2001 income of approximately $6.1 million, of which Plains Resources funded approximately 94%. Approximately $5.7 million of the 2001 charge and all of the 2000 charge were noncash and were not allocated to a segment.

Depreciation and Amortization. Depreciation and amortization expense was $34.1 million for the year ended December 31, 2002 compared to $24.3 million and $24.5 million for the periods ended December 31, 2001 and 2000, respectively. Excluding depreciation expense of $4.1 million related to the assets acquired in the Shell acquisition, depreciation and amortization expense would have been approximately $30.0 million for the 2002 period. Approximately $3.5 million of the $5.7 million increase in the adjusted depreciation and amortization for the 2002 period is related to the inclusion of the assets acquired in the Canadian acquisition for the entire 2002 period compared to only a portion of 2001. The remainder of the increase is related to an increase in debt issue costs related to the amendment of our credit facilities during 2002 and late 2001, the sale of senior notes in September 2002, and the completion of various capital expansion projects.

Depreciation and amortization expense for the 2000 period includes $4.6 million related to nonrecurring amortization of debt issue costs associated with credit facilities put in place during the fourth quarter of 1999, subsequent to the unauthorized trading losses. Excluding this nonrecurring cost, depreciation and amortization would have been approximately $19.9 million for the 2000 period. The increase of $4.4 million in 2001 from the adjusted 2000 depreciation and amortization expense is primarily related to the assets acquired in the Canadian acquisition.

Interest expense. Interest expense was $29.1 million for the year ended December 31, 2002 compared to $29.1 million and $28.7 million for the years ended December 31, 2001 and 2000, respectively. Interest expense was relatively flat in the 2002 period as compared to the prior year due to the impact of higher debt levels and commitment fees offset by lower average interest rates and the capitalization of interest. The overall increased average debt balance in 2002 is due to the portion of the Shell acquisition in August 2002 which was not refinanced with the issuance of equity. See “—Liquidity and Capital Resources—Liquidity.” During the third quarter of 2001, we issued a $200 million senior secured term B loan, the proceeds of which were used to reduce borrowings under the revolver. As such, our commitment fees on our revolver increased as they are based on unused availability. The lower interest rates in 2002 are due to a decrease in LIBOR and prime rates in the current year. In addition, approximately $0.8 million of interest expense was capitalized during 2002, in conjunction with expansion construction on our Cushing terminal compared to approximately $0.2 million in the 2001 period. Interest expense was slightly higher in the 2001 period as compared to the 2000 period primarily due to higher average debt balances, partially offset by lower average interest rates.

Gain on sale of assets. In March 2000, we sold to a unit of El Paso Corporation for $129.0 million the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas. Except for minor third party volumes, one of our subsidiaries, Plains Marketing, L.P., had been the sole shipper on this segment of the pipeline since its predecessor acquired the line from the Goodyear Tire & Rubber Company in July 1998. We realized net proceeds of approximately $124.0 million after the associated transaction costs and estimated costs to remove equipment. We used the proceeds from the sale to reduce outstanding debt. We recognized a gain of approximately $20.1 million in connection with the sale.

We suspended shipments of crude oil on this segment of the pipeline in November 1999. At that time, we owned approximately 5.2 million barrels of crude oil in the segment of the pipeline. We sold this crude oil from November 1999 to February 2000 for net proceeds of approximately $100.0 million, which were used for working capital purposes. We recognized gains of approximately $28.1 million in 2000 in connection with the sale of the linefill.

Early extinguishment of debt. During 2000, we recognized extraordinary losses, consisting primarily of unamortized debt issue costs, totaling $15.1 million related to the permanent reduction of the All American Pipeline, L.P. term loan facility and the refinancing of our credit facilities. In addition, interest and other income for the year ended December 31, 2000, includes $9.7 million of previously deferred gains from terminated interest rate swaps as a result of debt extinguishment.

Outlook

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of midstream crude oil assets. Such acquisition efforts involve participation by us in processes that have been made public, involve a number of potential buyers and are commonly referred to as "auction" processes, as well as situations where we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. In connection with these activities, we routinely incur third party costs, which are capitalized and deferred pending final outcome of the transaction. Deferred costs associated with successful transactions are capitalized as part of the transaction, while deferred costs associated with unsuccessful transactions are expensed at the time of such final determination. We can give you no assurance that our current or future acquisitions efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

We were very active in 2002 in evaluating several potential acquisitions and an unusually high level of internal and external resources were devoted to that effort. We were unsuccessful in our pursuit of several sizable acquisition opportunities that were evaluated on an auction basis and also one negotiated transaction that had nearly advanced to the execution stage when it was abruptly terminated by the seller. As a result, our fourth quarter results reflect a $1.0 million charge to G&A expenses associated with the third party costs of these unsuccessful transactions. At December 31, 2002, the remaining balance of deferred acquisition-related costs pending final outcome was not material.

Shutdown of Rancho Pipeline System. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminates in March 2003. Upon termination, the agreement requires the owners to take the pipeline system, in which we own an approximate 50% interest, out of service. Accordingly, we have notified our shippers that we will not accept nominations for movements after February 28, 2003. As contemplated at the time of the Shell acquisition, plans are currently under way to purge and idle portions of the pipeline system subject to final determination of the disposition of the system. During 2001, total volumes shipped from West Texas to the Gulf Coast Ship Channel on the Rancho System approximated 83,000 barrels per day. Since acquiring the pipeline in 2002, these volumes averaged approximately 91,000 barrels per day. We estimate that the shut-down of Rancho initially will have a negative influence on operating results in the first and second quarters of 2003 as we take the line out of service and deal with logistical issues. Once the pipeline is shut down, these volumes become candidates for shipment on the Basin system, which we operate and in which we own an approximate 87% interest. We estimate that increased movements on the Basin system will substantially offset the adverse impact on our operating results.

FERC Notice of Proposed Rulemaking. On August 1, 2002, the Federal Energy Regulatory Commission ("FERC") issued a Notice of Proposed Rulemaking that, if adopted, would amend its Uniform Systems of Accounts for oil pipeline companies with respect to participation of a FERC-Regulated subsidiary in the cash management arrangement of its non-FERC-regulated parent. Although it appears that, if adopted, the rule may affect the way in which we manage cash, we believe that the incremental costs will not be significant.

Sarbanes-Oxley Act and New SEC Rules. Several regulatory and legislative initiatives were introduced in 2002 in response to developments during 2001 and 2002 regarding accounting issues at large public companies, resulting disruptions in the capital markets and ensuing calls for action to prevent repetition of those events. We support the actions called for under these initiatives and believe these steps will ultimately be successful in accomplishing the stated objectives. However, implementation of reforms in connection with these initiatives will add to the costs of doing business for all publicly-traded entities, including the Partnership. These costs will have an adverse impact on future income and cash flow, especially in the near term as legal, financial and consultant costs are incurred to analyze the new requirements, formalize current practices and implement required changes to ensure that we maintain compliance with these new rules. We are not able to estimate the magnitude of increase in our costs that will result from such reforms.

Vesting of Unit Grants under LTIP and Conversion of Subordinated Units. In connection with our public offering in 1998, our general partner established a long-term incentive plan, which permits the grant of restricted units and unit options covering an aggregate of approximately 1.4 million units. Grants of approximately 1.0

million restricted units (and no unit options) are outstanding under the plan. A restricted unit grant entitles the grantee to receive a common unit upon the vesting of the restricted unit. Subject to additional vesting requirements, restricted units may vest in the same proportion as the conversion of our outstanding subordinated units into common units. Certain of the restricted unit grants contain additional vesting requirements tied to the Partnership achieving targeted distribution thresholds, generally $2.10, $2.30 and $2.50 per unit, in equal proportions.

Under generally accepted accounting principles, we are required to recognize an expense when the financial tests for conversion of subordinated units and required distribution levels are met. The financial tests involve GAAP accounting concepts as well as complex and esoteric cash receipts and disbursement concepts that are indexed to the minimum quarterly distribution rate of $1.80 per limited partner unit. Because of this complexity, it is difficult to forecast when the vesting of these restricted units will occur. However, at the current annualized distribution level of $2.15 per unit, assuming the subordination conversion test is met, the costs associated with the vesting of up to approximately 845,000 units would be incurred or accrued in the second half of 2003 or the first quarter of 2004. At an annualized distribution level of $2.30 to $2.49, the number of units would be approximately 935,000. At an annualized distribution level at or above $2.50, the number of units would be approximately 1,025,000. We are currently planning to issue units to satisfy the first 975,000 vested and delivered (after any units withheld for taxes) and to purchase units in the open market to satisfy any vesting obligations in excess of that amount. Issuance of units would result in a non-cash compensation expense, while a purchase of units would result in a cash charge to compensation expense. In addition, the "company match" portion of payroll taxes, plus the value of any units withheld for taxes, would result in a cash charge. The amount of the charge to expense will depend on the unit price on the date vesting occurs.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2002, we had a working capital deficit of approximately $34.3 million, approximately $436.9 million of availability under our revolving credit facility and $49.8 million of availability under the letter of credit and hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. In the past, we have generally maintained a positive working capital position. During 2002, we reduced our working capital, primarily through the (i) collection of accounts receivable and certain prepayments and the application of those proceeds to reduce long-term borrowings, and (ii) shifting a portion of our borrowings to finance certain contango inventory and LPG purchase requirements from long-term revolving credit facilities to our hedged inventory and letter of credit facility. The hedged inventory and letter of credit facility requires reduction in outstanding amounts at the time proceeds from the sale of the inventory are collected. Accordingly, amounts drawn under this facility are reflected as a current liability for hedged inventory expected to be sold within one year. In addition, approximately $3.1 million of the company's net liability under SFAS 133 is reflected as current. With respect to collections referred to in (i) above, during 2002, we collected a net amount of approximately $9.1 million of amounts that had been outstanding primarily since 1999 and 2000. In addition, as of December 31, 2002, to reduce credit risk, we had received approximately $21.5 million of payments related to December 2002 business. Typically, accounts receivable are collected within thirty days following the month of business. See "—Contingencies—Recent Disruptions in Industry Credit Markets."

We funded the purchase of the Shell acquisition on August 1, 2002, with funds drawn on our revolving credit facilities. Later in August, we completed a public offering of 6,325,000 common units priced at $23.50 per unit. Net proceeds from the offering, including our general partner's proportionate capital contribution and expenses associated with the offering, were approximately $145.0 million and were used to pay down our revolving credit facilities. During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012, which generated net proceeds of $196.3 million that we used to pay down our revolving credit facilities. See "—Credit Facilities and Long-Term Debt."

We believe that we have sufficient liquid assets, cash from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce a corollary adverse effect on our borrowing capacity.

Cash Flows

Cash flows for the years ended December 31, 2002, 2001 and 2000 were as follows:

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 173.9	$ (30.0)	$ (33.5)
Investing activities	(363.8)	(249.5)	211.0
Financing activities	189.5	279.5	(227.8)

Operating Activities. Net cash provided by operating activities for the year ended December 31, 2002 was $173.9 million as compared to cash used in operating activities of $30.0 million and $33.5 million for the years ended December 31, 2001 and 2000, respectively. Approximately $21.1 million of the increase is due to an increase in net income, predominantly related to our acquisitions completed in April and July 2001 and August 2002. The remainder of the increase is due to changes in working capital items related to the following: (i) the collection of amounts related to prior year balances as discussed above in "—Liquidity" and further below in "—Contingencies—Recent Disruptions in Industry Credit Markets"; (ii) the collection of prepayments due to the increase in credit risk associated with certain counter-parties; and (iii) the sale of hedged crude oil inventory purchased in 2001 and 2002 and the correlated changes in accounts receivable and accounts payable. In addition to the hedged inventory transactions having a positive effect on cash provided by operating activities for the year ended December 31, 2002, similar transactions had a negative effect on the year ended December 31, 2001 as the inventory was being purchased and stored, thus resulting in an even larger variance when comparing the two periods.

Net cash used in operating activities in 2001 is primarily attributable to inventory purchased and stored in our facilities for sale and delivery at a later date. Excluding these inventory purchases, cash provided by operating activities was approximately $88.0 million in 2001. Except for minor amounts, the inventory has been hedged against future price risk by using NYMEX transactions and fixed price sales contracts. Net cash used in operating activities in 2000 resulted primarily from the unauthorized trading losses. The losses were partially offset by increased margins due to the Scurlock and West Texas Gathering System acquisitions.

Investing Activities. Net cash used in investing activities in 2002 includes the payment of $311.4 million related to the Shell acquisition and related transaction costs, $7.1 million for the Butte acquisition and $5.4 million for the Cornerstone acquisition. Investing activities also includes $40.6 million of capital expenditures related to the Cushing expansion, the construction of the Marshall terminal in Canada and other capital projects.

Net cash used in investing activities in 2001 included $229.2 million for the Canadian acquisitions and $21.1 million primarily for other expansion and acquisition projects. Net cash provided by investing activities for 2000 included approximately $224.0 million of proceeds from the sale of the All American Pipeline and pipeline linefill offset by approximately $12.6 million of capital expenditures. Capital expenditures for 2000 included approximately $10.8 million for expansion capital and $1.8 million for maintenance capital.

Financing Activities. Cash provided by financing activities in 2002 consisted of approximately $344.6 million of net proceeds from the issuance of common units and senior unsecured notes, used primarily to fund capital projects and acquisitions and pay down outstanding balances on the revolving credit facility. Net repayments of our short-term and long-term revolving credit facilities during 2002 were $49.9 million. In addition, $99.8 million of distributions were paid to unitholders and the general partner during the year ended December 31, 2002.

Cash provided by financing activities in 2001 consisted primarily of net short-term and long-term borrowings of $134.3 million, proceeds from the issuance of common units of $227.5 million, the payment of $75.9 million in distributions to unitholders and the payment of $6.4 million in financing costs. Cash used in financing activities in 2000 consisted primarily of net short-term and long-term payments of $47.5 million, the repayment of subordinated debt of $114.0 million to our former general partner and distributions to unitholders of $59.6 million. Cash used to reduce the debt primarily came from the asset sales discussed above. Cash used to repay the $114.0 million of subordinated debt to our former general partner came from our revolving credit facility, which was refinanced in May 2000.

Universal Shelf

We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $700 million of debt or equity securities. At December 31, 2002, we have approximately $421 million of remaining availability under this registration statement.

Credit Facilities and Long-term Debt

During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012. The notes were issued by us and a 100% owned finance subsidiary (neither of which have independent assets or operations) at a discount of $0.4 million, resulting in an effective interest rate of 7.78%. Interest payments are due on April 15 and October 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor.

During 2002, we amended our credit facilities to remove a condition requiring us to obtain lender approval before making any acquisition greater than $50.0 million and to accommodate the increased activity level associated with the expanded asset base, while preserving our ability to pursue additional acquisitions.

As amended during 2002 and giving effect to the third quarter capital raising activities, our credit facilities consist of a $350.0 million senior secured letter of credit and hedged inventory facility (with current lender commitments totaling $200.0 million), and a $747.0 million senior secured revolving credit and term loan facility, each of which is secured by substantially all of our assets. The terms of our credit facilities enable us to expand the commitments under the letter of credit and hedged inventory facility from $200.0 million to $350.0 million without additional approval from existing lenders. The revolving credit and term loan facility consists of a $420.0 million domestic revolving facility (with a $10.0 million letter of credit sublimit), a $30.0 million Canadian revolving facility (with a $5.0 million letter of credit sublimit), a $99.0 million term loan, and a $198.0 million term B loan.

The facilities have final maturities as follows:

- as to the $350.0 million senior secured letter of credit and hedged inventory facility and the aggregate $450.0 million domestic and Canadian revolver portions, in April 2005;
- as to the $99.0 million term loan, in May 2006; and
- as to the $198.0 million term B loan, in September 2007.

Our credit facilities and the indenture governing the 7.75% senior notes contain cross default provisions. Our credit facilities prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness;
- grant liens;
- sell assets;
- make investments;
- engage in transactions with affiliates;
- enter into prohibited contracts; and
- enter into a merger or consolidation.

Our credit facilities treat a change of control as an event of default and also require us to maintain:

- a current ratio (as defined) of at least 1.0 to 1.0;
- a debt coverage ratio which will not be greater than: 5.25 to 1.0 on all outstanding debt and 4.0 to 1.0 on secured debt;
- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt to capital ratio of not greater than 0.7 to 1.0 through March 30, 2003, and 0.65 to 1.0 at any time thereafter.

For covenant compliance purposes, letters of credit and borrowings under the letter of credit and hedged inventory facility are excluded when calculating the debt coverage and debt to capital ratios. Additionally, under the covenants, unborrowed availability under the $450 million domestic and Canadian revolving credit facilities is added to working capital to calculate the current ratio for compliance purposes. At December 31, 2002, unborrowed availability was approximately $436.9 for purposes of calculating the current ratio.

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt and to foreclose on the assets securing the credit facilities. As long as we are in compliance with our credit agreements, they do not restrict our ability to make distributions of “available cash” as defined in our partnership agreement. We are currently in compliance with the covenants contained in our credit facilities and 7.75% senior notes credit agreements.

The amended facility permits us to issue up to an aggregate of $400.0 million of senior unsecured debt that has a maturity date extending beyond the maturity date of the existing credit facility, and provides a mechanism to reduce the amount of the domestic revolving credit facility. The foregoing description of the credit facility incorporates the reduction associated with the $200 million senior note offering completed in September 2002. Depending on the amount of additional senior indebtedness incurred, the domestic revolving credit facility will be reduced by an amount equating to 40% to 63% of any incremental indebtedness up to the aggregate $400 million limitation.

The average life of our debt capitalization at December 31, 2002, was approximately 6.3 years. At the end of the year we had approximately $13.1 million outstanding under our $450 million of revolving credit facilities that mature in 2005, approximately $297 million of senior secured term loans with final maturity dates in 2006 and 2007 and $200 million of senior notes which mature in 2012. We have classified the $9 million of term loan payments due in 2003 as long term due to our intent and ability to refinance those maturities using the revolving facility.

Term loan payments are as follows (in millions):

Calendar Year		Payment
2003	$	9.0
2004		10.0
2005		10.0
2006		78.0
2007		190.0
Total	$	297.0

We manage our exposure to increasing interest rates. Based on December 31, 2002, debt balances, floating rate indexes at the end of January 2003, our credit spread under our credit facilities and the combination of our fixed rate debt and current interest rate hedges, the average interest rate was approximately 6.1%, excluding non-use and facilities fees, which will vary based on usage and outstanding balance. Based on current amounts outstanding, we estimate these fees will average approximately $2.2 million per year. We have locked-in interest rates (excluding the credit spread under the credit facilities) for approximately 60% of our total debt for the next year, 50% for the next four years and 40% for the next ten years.

Contingencies

Recent Disruptions in Industry Credit Markets. As a result of business failures, revelations of material misrepresentations and related financial restatements by several large, well-known companies in various industries during 2001 and 2002, there have been significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and troubling disclosures by several large, diversified energy companies, the energy industry has been especially impacted by these developments, with the rating agencies downgrading a number of large, energy-related companies. Accordingly, in this environment we are exposed to an increased level of direct and indirect counterparty credit and performance risk.

The majority of our credit extensions and therefore our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. In transacting business with our counterparties, we must determine the amount, if any, of open credit lines to extend to our counterparties and the form and amount of financial performance assurances we may require. As a result of these developments, during 2002 we modified our ongoing credit arrangements with certain counterparties, reducing or eliminating the amount of open credit we extend and requiring prepayments or standby letters of credit for business activities that exceed these revised credit limits.

The vast majority of our accounts receivable settle monthly and any collection delays generally involve discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered or exchanged and associated billing delays. At December 31, 2002, approximately 99% of our net accounts receivables included in current assets are less than 60 days past scheduled invoice date. The majority of the remaining 1% and the balance of accounts receivable classified as long-term relate to monthly periods leading up to and immediately following the disclosure of unauthorized trading losses that we experienced in late 1999. Such balances are subject to ongoing reconciliations primarily to resolve discrepancies associated with pricing, volumes, quality or crude oil exchange imbalances. Following the unauthorized trading loss disclosure, a significant number of our suppliers and trading partners temporarily reduced or eliminated our open credit and demanded payments or withheld payments due us before disputed amounts or discrepancies were reconciled in accordance with customary industry practices. Because these matters also arose in the midst of various software systems conversions and acquisition integration activities, our effort to resolve outstanding claims and discrepancies has included reprocessing and integrating historical information on numerous software platforms. During 2002, significant, concerted effort was directed to resolving these matters in an ongoing effort to bring substantially all receivable balances to within sixty days of scheduled invoice date. As a result of this effort, the aggregate balance of all account receivable balances greater than sixty days past scheduled invoice date at December 31, 2001 was reduced by approximately 64% and the balance of our accounts receivable included in current assets that were less than 60 days past scheduled invoice date improved to 99% at December 31, 2002 from 93% at December 31, 2001. Based on the work performed to date, we believe net receivable balances greater than sixty days past scheduled invoice date are collectible or subject to offsets and consider our reserves adequate. However, in the event our counterparties experience an unanticipated deterioration in their credit-worthiness, any addition to existing reserves or write-offs in excess of such reserves would result in a noncash charge to earnings. We do not believe any such charge would have a material effect on our cash flow or liquidity.

To date, these market disruptions have not had a material adverse impact on our activities or on obtaining open credit for our account with counterparties. In February 2003 Standard and Poor's upgraded our corporate credit rating to investment grade, assigning us a rating of BBB-, stable outlook. In September 2002, Moody's Investor Services upgraded our senior implied credit rating to Ba1, stable outlook. You should note that a credit rating is not a recommendation to buy, sell, or hold securities, and may be subject to revision or withdrawal at any time.

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the short supply controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Department of Commerce. We have determined that we may have exceeded the quantity of crude oil exports authorized by previous licenses. Export of crude oil in excess of the authorized amounts is a violation of the EAR. On October 18, 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and have received a new license allowing for exports of volumes more than adequately reflecting our anticipated needs. At this time, we have received no indication whether the BIS intends to charge us with a violation of the EAR or, if so, what penalties would be assessed. As a result, we cannot estimate the ultimate impact of these potential violations.

Pipeline and Storage Regulation. We are subject to the U.S. Department of Transportation's (the "DOT's") pipeline integrity rules, which require continual assessment of pipeline segments that could affect "high consequence areas." Our compliance costs will vary from year to year based on the assessment priority placed on particular line segments. Based on currently available information, we estimate that such costs will average approximately $1.9 million per year in 2003 and 2004. Such amounts incorporate approximately $1 million per year associated with assets acquired in the Shell acquisition. We will continue to refine our estimates as data from initial assessments is collected. See Items 1 and 2. "—Business and Properties—Regulation—Pipeline and Storage Regulation."

The DOT has adopted API 653 as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks subject to DOT jurisdiction (approximately 61% of our 22.7 million barrels). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required by 2009. We have commenced our compliance activities under the standard and, based on currently available information, we estimate that we will spend approximately $1.0 million per year in 2003 and 2004 in connection with these activities. Such amounts incorporate costs associated with assets acquired in the Shell acquisition. We will continue to refine our estimates as data from initial assessments is collected.

Other. A pipeline, terminal or other facilities may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers all of our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. The events of September 11, 2001, and their overall effect on the insurance industry has had an adverse impact on availability and cost of coverage. Due to these events, insurers have excluded acts of terrorism and sabotage from our insurance policies. On certain of our key assets, we purchased a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets (including our nation's pipeline infrastructure) may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. The DOT has developed a security guidance document and has issued a security circular that defines critical pipeline facilities and appropriate countermeasures for protecting them, and explains how DOT plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the DOT, we have specifically identified certain of our facilities as DOT "critical facilities" and therefore potential terrorist targets. In compliance with DOT guidance, we are performing vulnerability analyses on such facilities. Upon completion of such analyses, we will institute as appropriate any indicated security measures or procedures that are not already in place. We cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business whether insured or not.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business.

Capital Requirements

We have made and will continue to make capital expenditures for acquisitions and expansion and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations, credit facility borrowings, the issuance of senior unsecured notes and the sale of additional common units.

We expect to spend approximately $83.0 million on expansion capital projects during 2003. This includes approximately $50.0 million for one acquisition that we closed in the first quarter of 2003 and two additional acquisitions currently being negotiated which, if consummated, are expected to close in March or April of 2003. The assets acquired in the transaction that closed in the first quarter consist of a 347-mile crude oil pipeline system and approximately 695,000 barrels of crude oil storage capacity. We plan to replace approximately 32 miles of existing pipe on this pipeline and to build a twelve-mile extension of the system to connect to our terminal in Cushing. Approximately $8 million of costs related to this acquisition will not be incurred until 2004.

Our expansion capital estimate also includes costs for various internal expansion projects and approximately $18.1 million to construct crude oil gathering and transmission lines in West Texas. We also estimate we will spend approximately $8.5 million in maintenance capital during 2003. In addition, we anticipate increasing our share of the crude oil linefill in the Basin Pipeline throughout 2003, potentially adding as much as one million barrels as we expand our shipment activities on this pipeline. The cost to purchase this linefill will depend on market conditions at the time of purchase.

Commitments

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2002 (in millions):

Contractual Obligations	2003	2004	2005	2006	2007	Thereafter	Total
Long-term debt (including current maturities)	$ 9.0	$ 10.0	$ 23.1	$ 78.0	$ 190.0	$ 200.0	$ 510.1
Operating leases	9.4	9.6	9.4	7.0	2.7	0.5	38.6
Total contractual cash obligations	$ 18.4	$ 19.6	$ 32.5	$ 85.0	$ 192.7	$ 200.5	$ 548.7

Operating leases are primarily for office rent and trucks used in our gathering activities. Other than the amounts reflected above for operating leases, we have no other financing arrangements that are not reflected on the consolidated balance sheet. As is common within the industry, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminalling and storage of crude oil. We believe that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

We will distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all cash and cash equivalents on hand at the end of the quarter less reserves established by our general partner for future requirements. Minimum quarterly distributions are $0.45 per unit for each full fiscal quarter. Distributions of available cash to the holders of subordinated units are subject to the prior rights of the holders of common units to receive the minimum quarterly distributions for each quarter during the subordination period, and to receive any arrearages in the distribution of minimum quarterly distributions on the common units for prior quarters during the subordination period. There were no arrearages on common units at December 31, 2002. On February 14, 2003, we paid a cash distribution of $0.5375 per unit on all outstanding units. The total distribution paid was approximately $28.2 million, with approximately $21.2 million paid to our common unitholders, $5.4 million paid to our subordinated unitholders and $1.6 million paid to our general partner for its general partner ($0.6 million) and incentive distribution interests ($1.0 million).

Our general partner is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per limited partner unit, 25% of amounts we distribute in excess of $0.495 per limited partner unit and 50% of amounts we distribute in excess of $0.675 per limited partner unit. See Item 13. “Certain Relationships and Related Transactions—Our General Partner.”

In connection with our crude oil marketing, we provide certain purchasers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At December 31, 2002, we had outstanding letters of credit of approximately $52.5 million. These letters of credit are secured by our crude oil inventory and accounts receivable.

Related Party Transactions

We have a long-term agreement with Plains Resources (including its subsidiaries that conduct exploration and production activities) pursuant to which we purchase for resale at market prices all of Plains Resources’ equity crude oil production for a fee of $0.20 per barrel. In November 2001, the agreement automatically extended for three years. The fee is subject to adjustment every three years based on then-existing market conditions. For the years ended December 31, 2002, 2001 and 2000, we paid approximately $247.7 million, $223.2 million and $244.9 million, respectively for Plains Resources' production and recognized gross margin of approximately $1.8 million, $1.8 million and $1.7 million. On December 18, 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production ("PXP"), to its shareholders. PXP is a successor participant to this marketing agreement.

Recent Accounting Pronouncements

In December 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 148 "Accounting for Stock-Based Compensation—Transition and Disclosure." SFAS 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 in both annual and interim financial statements. SFAS 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. Our general partner has stock-based employee compensation plans (see Notes 12 and 13). These plans are accounted for under the "fair value" method as described in SFAS 123. Therefore, we do not believe that the adoption of this statement will have a material effect on either our financial position, results of operations, cash flows or disclosure requirements.

In October 2002, the Emerging Issues Task Force ("EITF") reached consensus on certain issues in EITF Issue No. 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under Issues No. 98-10 and 00-17." The consensus reached included (i) rescinding EITF 98-10 and (ii) the requirement that mark-to-market gains and losses on trading contracts (whether realized or unrealized and whether financially or physically settled) be shown net in the income statement using the indicators identified in Issue No. 98-10. The EITF provided guidance that, beginning on October 25, 2002, all new contracts that would have been accounted for under EITF 98-10 should no longer be marked-to-market through earnings unless such contracts fall within the scope of SFAS 133. All of the contracts that we have accounted for under EITF 98-10 fall within the scope of SFAS 133 and therefore will continue to be marked-to-market through earnings under the provisions of that rule. Therefore, the adoption of this rule did not have a material effect on either our financial position, results of operations or cash flows.

In June 2002, the FASB issued SFAS No. 146 "Accounting for Costs Associated with Exit or Disposal Activities." SFAS 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the obligation is incurred rather than at the date of the exit plan. This Statement is effective for exit or disposal activities that are initiated after December 31, 2002. We have not initiated exit or disposal activities that are subject to this statement and thus do not believe that the adoption of SFAS 146 will have a material effect on either our financial position, results of operations or cash flows.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." SFAS 145 rescinds, updates, clarifies and simplifies existing accounting pronouncements. Among other things, SFAS 145 rescinds SFAS 4, which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. Under SFAS 145, the criteria in Accounting Principles Board No. 30 will now be used to classify those gains and losses. The adoption of this and the remaining provisions of SFAS 145 did not have a material effect on our financial position or results of operations. However, any future extinguishments of debt may impact income from continuing operations.

In June 2001, the FASB issued SFAS No. 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Effective January 1, 2003, we adopted SFAS 143, as required. Determination of the amounts to be recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. The majority of our assets, primarily related to our pipeline operations segment, have obligations to perform removal and/or remediation activities when the asset is retired. However, the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. We will record such asset retirement obligations in the period in which we determine the settlement dates. The cumulative effect of adopting this statement will not have a material impact on our financial position, results of operations or cash flows.

Risk Factors Related to Our Business

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. Production from these offshore fields has experienced substantial production declines since 1995.

A significant portion of our gross margin is derived from pipeline transportation margins associated with the Santa Ynez and Point Arguello fields located offshore California. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline tariff revenues of approximately $3.1 million. In addition, any production disruption from these fields due to production problems, transportation problems or other reasons would have a material adverse effect on our business.

Potential future acquisitions and expansions, if any, may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. The Shell acquisition represents a significant acquisition for us and, as a result, we may encounter difficulties integrating this acquisition with our existing business and our other recent acquisitions and successfully managing the rapid growth we expect to experience from these acquisitions. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our crude oil marketing business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

As a result of business failures, revelations of material misrepresentations and related financial restatements by several large, well-known companies in various industries over the past year, there have been significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and troubling disclosures by several large, diversified energy companies, the energy industry has been especially impacted by these developments, with the rating agencies downgrading a number of large, energy related companies. Accordingly, in this environment we are exposed to an increased level of direct and indirect counter-party credit and performance risk. There can be no assurance that we have adequately assessed the credit worthiness of our existing or future counter-parties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

The profitability of our pipeline operations depends on the volume of crude oil shipped by third parties.

Third party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. For example, an average 25,000 barrel per day variance in the Basin Pipeline System, the primary asset we acquired from Shell, equivalent to an approximate 10% volume variance on that pipeline system, would result in an approximate $3.8 million change in annualized gross margin.

In 1999, we suffered a large loss from unauthorized crude oil trading by a former employee. A loss of this kind could occur again in the future in spite of our best efforts to prevent it.

Generally, it is our policy that as we purchase crude oil, we establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation under futures contracts on the NYMEX and over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is not to acquire and hold crude oil, futures contracts or derivative products for the purpose of speculating on price changes. We discovered in November 1999 that this policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181.0 million, including estimated costs and legal expenses. We have taken steps within our organization to enhance our processes and procedures to prevent future unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our trading policies and procedures, particularly if deception or other intentional misconduct is involved.

The success of our business strategy to increase and optimize throughput on our pipeline and gathering assets is dependent upon our securing additional supplies of crude oil.

Our operating results are dependent upon securing additional supplies of crude oil from increased production by oil companies and aggressive lease gathering efforts. The ability of producers to increase production is dependent on the prevailing market price of oil, the exploration and production budgets of the major and independent oil companies, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives and other matters beyond our control. There can be no assurance that production of crude oil will rise to sufficient levels to cause an increase in the throughput on our pipeline and gathering assets.

Our operations are dependent upon demand for crude oil by refiners in the Midwest and on the Gulf Coast. Any decrease in this demand could adversely affect our business.

Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets, and any decrease in this demand could adversely affect our business. Demand for crude oil is dependent upon the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand.

We face intense competition in our terminalling and storage activities and gathering and marketing activities.

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control greater supplies of crude oil.

The profitability of our gathering and marketing activities depends primarily on the volumes of crude oil we purchase and gather.

To maintain the volumes of crude oil we purchase, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines in crude oil production from depleting wells or volumes lost to competitors. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is low and competition to gather available production is intense. Generally, because producers experience inconveniences in switching crude oil purchasers, such as delays in receipt of proceeds while awaiting the preparation of new division orders, producers typically do not change purchasers on the basis of minor variations in price. Thus, we may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil. We estimate that a 5,000 barrel per day decrease in barrels gathered by us would have an approximate $900,000 per year negative impact on gross margin. This impact is based on a reasonable margin throughout various market conditions. Actual margins vary based on the location of the crude oil, the strength or weakness of the market and the grade or quality of crude oil.

We are exposed to the credit risk of our customers in the ordinary course of our gathering and marketing activities.

In those cases where we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all parties. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk, and there can be no assurance that we will not experience losses in dealings with other parties.

Our operations are subject to federal and state environmental and safety laws and regulations relating to environmental protection and operational safety.

Our pipeline, gathering, storage and terminalling facilities operations are subject to the risk of incurring substantial environmental and safety related costs and liabilities. These costs and liabilities could arise under increasingly strict environmental and safety laws, including regulations and enforcement policies, or claims for damages to property or persons resulting from our operations. If we were not able to recover such resulting costs through insurance or increased tariffs and revenues, our cash flows and results of operations could be materially impacted.

The transportation and storage of crude oil results in a risk that crude oil and other hydrocarbons may be suddenly or gradually released into the environment, potentially causing substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, liability to private parties for personal injury or property damages, and significant business interruption.

Our Canadian pipeline assets are subject to federal and provincial regulation.

Our Canadian pipeline assets are subject to regulation by the National Energy Board and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these agencies has the power to determine the rates we are allowed to charge for transportation on such pipeline. The extent to which regulatory agencies can override existing transportation contracts has not been fully decided.

Our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets.

Reduced throughput on these interconnecting pipelines as a result of testing, line repair, reduced operating pressures or other causes could result in reduced throughput on our pipeline systems that would adversely affect our profitability.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our unitholders and our ability to make payments on our debt securities.

The after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate rate. Some or all of the distributions made to unitholders would be treated as dividend income, and no income, gains, losses or deductions would flow through to unitholders. Treatment of us as a corporation would cause a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of the common units. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. The 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.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risks*

We are exposed to various market risks, including volatility in (i) crude oil and LPG commodity prices, (ii) interest rates and (iii) currency exchange rates. We utilize various derivative instruments to manage such exposure. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure our hedging activities address our market risks. We have a risk management function that has direct responsibility and authority for our risk policies and our trading controls and procedures and certain aspects of corporate risk management. To hedge the risks discussed above we engage in price risk management activities that we categorize by the risks we are hedging. The following discussion addresses each category of risk.

Commodity Price Risk

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the New York Mercantile Exchange and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies (see Note 6 to our consolidated financial statements for a discussion of the mitigation of credit risk). Our policy is to purchase only crude oil for which we have a market, and to structure our sales contracts so that crude oil price fluctuations do not materially affect the gross margin we receive. Except for inventory transactions that generally do not exceed approximately 500,000 barrels, we do not enter into derivative transactions for speculative trading purposes. Similarly, while we seek to maintain a position that is substantially balanced within our LPG activities, as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions, from time to time we experience net unbalanced positions for short periods of time. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, our policies provide that any net imbalance may not exceed 200,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. See Items 1 and 2. “Business and Properties—Crude Oil Volatility; Counter-Cyclical Balance; Risk Management.”

As a result of production and delivery variances associated with our lease purchase activities, from time to time we experience net unbalanced positions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in this controlled trading program for up to 500,000 barrels. This activity is monitored independently by our risk management function and must take place within predefined limits and authorizations. In order to hedge margins involving our physical assets and manage risks associated with our crude oil purchase and sale obligations, we use derivative instruments, including regulated futures and options transactions, as well as over-the-counter instruments. In analyzing our risk management activities, we draw a distinction between enterprise-level risks and trading-related risks. Enterprise-level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading-related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the core business; rather, those risks arise as a result of engaging in the trading activity. We have a Risk Management Committee that approves all new risk management strategies through a formal process. With the partial exception of the limited 500,000-barrel program, our approved strategies are intended to mitigate enterprise-level risks that are inherent in our core businesses of gathering and marketing and storage.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility than in the past. This accounting treatment is discussed further under Note 2 “Summary of Significant Accounting Policies” in the “Notes to the Consolidated Financial Statements.”

All of our open commodity price risk derivatives at December 31, 2002 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below (in millions):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ 0.6	$ (4.3)
Swaps and options contracts	$ (0.2)	$ 2.0
LPG:		
Futures contracts	$ —	$ —
Swaps and options contracts	$ (0.4)	$ 0.2

The fair values of the futures contracts are based on quoted market prices obtained from the NYMEX. The fair value of the swaps and option contracts are estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. These quotes are compared to the contract price of the swap, which approximates the gain or loss that would have been realized if the contracts had been closed out at year end. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. The assumptions in these estimates as well as the source is maintained by the independent risk control function. All hedge positions offset physical positions exposed to the cash market; none of these offsetting physical positions are included in the above table. Price-risk sensitivities were calculated by assuming an across-the-board 10 percent decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10 percent change in prompt month crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table due to lower volatility in out-month prices.

Interest Rate Risk

We utilize both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities and our term loans. Therefore, we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at December 31, 2002. The 7.75% senior notes issued during 2002 are fixed rate notes and thus are not subject to market risk. Our variable rate debt bears interest at LIBOR or prime plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2002. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates (dollars in millions).

	Expected Year of Maturity						
	2003	2004	2005	2006	2007	Thereafter	Total
Liabilities:							
Short-term debt (and current maturities of long-term debt)—variable rate	$99.2	$ —	$ —	$ —	$ —	$ —	$ 99.2
Average interest rate	3.4%	—	—	—	—	—	3.4%
Long-term debt—variable rate	$ 9.0	$10.0	$23.1	$78.0	$190.0	$ —	$310.1
Average interest rate	3.9%	3.9%	4.4%	3.9%	3.9%	0.0%	3.9%

Interest rate swaps, collars and treasury locks are used to hedge underlying interest payment obligations. We estimate the fair value of these instruments based on current termination values. These instruments hedge interest rates on specific debt issuances and qualify for hedge accounting. The interest rate differential is reflected as an adjustment to interest expense over the life of the instruments.

The table shown below summarizes the fair value of our interest rate swaps and treasury lock by the year of maturity (in millions):

	Year of Maturity				
	2003	2004	2005	2006	Total
Interest rate swaps	$ —	$ (1.7)	$ —	$ (4.6)	$ (6.3)
Treasury lock	(3.3)	—	—	—	(3.3)
Total	$ (3.3)	$ (1.7)	$ —	$ (4.6)	$ (9.6)

The instruments outstanding at December 31, 2002, consist of interest rate swaps and a treasury lock with an aggregate notional principal amount of $150 million. The interest rate swaps are based on LIBOR rates and provide for a LIBOR rate of 5.1% for a $50.0 million notional principal amount expiring October 2006, and a LIBOR rate of 4.3% for a $50.0 million notional principal amount expiring March 2004. Interest on the underlying debt being hedged is based on LIBOR plus a margin. During 2002, we entered into a treasury lock in anticipation of the issuance of our 7.75% senior notes due October 2012 and potential subsequent add-on thereto. A treasury lock is a financial derivative instrument that enables the company to lock in the U.S. Treasury Note rate. The treasury lock has a notional principal amount of $50 million and an effective interest rate of 4.60% and matures in January, 2003. In January, 2003, the treasury lock maturity was extended to March, 2003 with an effective interest rate of 4.68%.

Currency Exchange Risk

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period.

Since substantially all of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments include forward exchange contracts, forward extra option contracts and cross currency swaps. Additionally, at December 31, 2002, $2.7 million ($4.3 million Canadian based on a Canadian-U.S. dollar exchange rate of 1.58) of our long-term debt was denominated in Canadian dollars. All of the financial instruments utilized are placed with large creditworthy financial institutions.

At December 31, 2002, we had forward exchange contracts and forward extra option contracts that allow us to exchange $3.0 million Canadian for at least $1.9 million U.S. quarterly during 2003 (based on a Canadian-U.S. dollar exchange rate of 1.54). At December 31, 2002, we also had cross currency swap contracts for an aggregate notional principal amount of $24.8 million effectively converting this amount of our senior secured term loan (25% of the total) from U.S. dollars to $38.3 million of Canadian dollar debt (based on a Canadian-U.S. dollar exchange rate of 1.55). The terms of this contract mirror the term loan, matching the amortization schedule and final maturity in May 2006.

We estimate the fair value of these instruments based on current termination values. The table shown below summarizes the fair value of our foreign currency hedges by year of maturity (in millions):

	Year of Maturity				
	2003	2004	2005	2006	Total
Forward exchange contracts	$ 0.1	$ —	$ —	$ —	$ 0.1
Forward extra options	0.2	—	—	—	0.2
Cross currency swaps	—	—	—	0.3	0.3
Total	$ 0.3	$ —	$ —	$ 0.3	$ 0.6

Item 8. ***Financial Statements and Supplementary Data***

The information required here is included in the report as set forth in the “Index to Financial Statements” on page F-1.

Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

PART III

Item 10. *Directors and Executive Officers of Our General Partner*

Partnership Management and Governance

As is the case with many publicly traded partnerships, we do not directly have officers, directors or employees. Our operations and activities are managed by the general partner of our general partner, Plains All American GP LLC, which employs our management and operational personnel. References to our general partner, unless the context otherwise requires, include Plains All American GP LLC. References to our officers, directors and employees are references to the officers, directors and employees of Plains All American GP LLC (or, in the case of our Canadian operations, PMC (Nova Scotia) Company).

Our general partner manages our operations and activities. Unitholders do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to the unitholders, as limited by our partnership agreement. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations on a non-recourse basis.

Our partnership agreement provides that the general partner will manage and operate the partnership and that, unlike holders of common stock in a corporation, unitholders will have only limited voting rights on matters affecting our business or governance. Specifically, the partnership agreement defines “Board of Directors” to mean the board of directors of Plains All American GP LLC, which is elected by the members of Plains All American GP LLC, and not by the unitholders. Thus, the corporate governance of Plains All American GP LLC is, in effect, the corporate governance of the Partnership, subject in all cases to any specific unitholder rights contained in the partnership agreement.

We have an audit committee that reviews our external financial reporting, engages our independent auditors and reviews the adequacy of our internal accounting controls, and a compensation committee, which reviews and makes recommendations regarding the compensation for the executive officers and administers our equity compensation plans. We have a finance committee that advises and assists management with respect to financial matters. We also have an interim corporate governance committee that is reviewing our governance practices in light of recent governance reform initiatives. In addition, our partnership agreement provides for the establishment/activation of a conflicts committee as circumstances warrant to review conflicts of interest between us and our general partner or the owners of our general partner. We currently have a standing conflicts committee consisting of two members who are not officers or employees of our general partner or directors, officers or employees of its affiliates. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

Directors and Executive Officers

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our general partner. Directors were elected in June 2001 for an initial three-year term, and will be elected annually thereafter. Certain owners of our general partner each have the right to separately designate a member of our board. Such designees are indicated in the footnote to the following table.

Name	Age	Position with Our General Partner
Greg L. Armstrong	44	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis	45	President and Chief Operating Officer
Phillip D. Kramer	47	Executive Vice President and Chief Financial Officer
George R. Coiner	52	Senior Vice President
Mark F. Shires	45	Vice President—Operations
Jim G. Hester	43	Vice President—Acquisitions
Tim Moore	45	Vice President, General Counsel and Secretary
Alfred A. Lindseth	33	Vice President—Administration
Everardo Goyanes	58	Director and Member of Audit* and Conflicts Committees
Gary R. Petersen(1)	56	Director and Member of Compensation Committee*
John T. Raymond(1)	32	Director and Member of Finance Committee
Robert V. Sinnott(1)	53	Director and Member of Finance and Compensation Committees
Arthur L. Smith	50	Director and Member of Audit, Conflicts*, Interim Governance and Compensation Committees
J. Taft Symonds(1)	63	Director and Member of Finance*, Interim Governance and Audit Committee

* Indicates chairman of committee

(1) Pursuant to the Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Petersen has been designated by E-Holdings III, L.P., an affiliate of EnCap Investments LLC, of which he is a Managing Director. Mr. Raymond has been designated by Sable Investments, L.P., in which Mr. Raymond indirectly owns a limited partner interest. Sable Investments, L.P. is controlled by James M. Flores, the Executive Chairman of Plains Resources and also the Chairman and Chief Executive Officer of Plains Exploration and Production. Mr. Sinnott has been designated by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is a Vice President. Mr. Symonds has been designated by Plains Resources, of which he is a director. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters—Beneficial Ownership of General Partner Interest."

Greg L. Armstrong has served as Chairman of the Board and Chief Executive Officer since our formation. He has also served as a director of our general partner or former general partner since our formation. In addition, he was President, Chief Executive Officer and director of Plains Resources from 1992 to May 2001. He previously served Plains Resources as: President and Chief Operating Officer from October to December 1992; Executive Vice President and Chief Financial Officer from June to October 1992; Senior Vice President and Chief Financial Officer from 1991 to 1992; Vice President and Chief Financial Officer from 1984 to 1991; Corporate Secretary from 1981 to 1988; and Treasurer from 1984 to 1987.

Harry N. Pefanis has served as President and Chief Operating Officer since our formation. He was also a director of our former general partner. In addition, he was Executive Vice President—Midstream of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as: Senior Vice President from February 1996 until May 1998; Vice President—Products Marketing from 1988 to February 1996; Manager of Products Marketing from 1987 to 1988; and Special Assistant for Corporate Planning from 1983 to 1987. Mr. Pefanis was also President of several former midstream subsidiaries of Plains Resources until our formation in 1998.

Phillip D. Kramer has served as Executive Vice President and Chief Financial Officer since our formation. In addition, he was Executive Vice President and Chief Financial Officer of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as: Senior Vice President and Chief Financial Officer from May 1997 until May 1998; Vice President and Chief Financial Officer from 1992 to 1997; Vice President from 1988 to 1992; Treasurer from 1987 to March 2001; and Controller from 1983 to 1987.

George R. Coiner has served as Senior Vice President since our formation. In addition, he was Vice President of Plains Marketing & Transportation Inc., a former midstream subsidiary of Plains Resources from November 1995 until our formation in 1998. Prior to joining Plains Marketing & Transportation Inc., he was Senior Vice President, Marketing with Scurlock Permian Corp.

Mark F. Shires has served as Vice President—Operations since August 1999. He served as Manager of Operations from April 1999 until he was elected to his current position. In addition, he was a business consultant from 1996 until April 1999. He served as a consultant to Plains Marketing & Transportation Inc. and Plains All American Pipeline from May 1998 until April 1999. He previously served as President of Plains Terminal & Transfer Corporation, a former midstream subsidiary of Plains, from 1993 to 1996.

Jim G. Hester has served as Vice President—Acquisitions since March 2002. Prior to joining us, Mr. Hester was Senior Vice President—Special Projects of Plains Resources. From May 2001 to December 2001, he was Senior Vice President—Operations for Plains Resources. From May 1999 to May 2001, he was Vice President—Business Development and Acquisitions of Plains Resources. He was Manager of Business Development and Acquisitions of Plains Resources from 1997 to May 1999, Manager of Corporate Development from 1995 to 1997 and Manager of Special Projects from 1993 to 1995. He was Assistant Controller from 1991 to 1993, Accounting Manager from 1990 to 1991 and Revenue Accounting Supervisor from 1988 to 1990.

Tim Moore has served as Vice President, General Counsel and Secretary since May 2000. In addition, he was Vice President, General Counsel and Secretary of Plains Resources from May 2000 to May 2001. Prior to joining Plains Resources, he served in various positions, including General Counsel—Corporate, with TransTexas Gas Corporation from 1994 to 2000. He previously was a corporate attorney with the Houston office of Weil, Gotshal & Manges LLP. Mr. Moore also has seven years of industry experience as a petroleum geologist.

Alfred A. Lindseth has served as Vice President—Administration since March 2001. He served as Risk Manager from March 2000 until he was elected to his current position. He previously served PricewaterhouseCoopers LLP in its Financial Risk Management Practice section as a Consultant from 1997 to 1999 and as Principal Consultant from 1999 to March 2000. He also served GSC Energy, an energy risk management brokerage and consulting firm, as Manager of its Oil & Gas Hedging Program from 1995 to 1996 and as Director of Research and Trading from 1996 to 1997.

Everardo Goyanes has served as a director of our general partner or former general partner since May 1999. Mr. Goyanes has been President and Chief Executive Officer of Liberty Energy Holdings since May 2000. From 1999 to May 2000, he was a financial consultant specializing in natural resources. From 1989 to 1999, he was Managing Director of the Natural Resources Group of ING Barings Furman Selz. He was a financial consultant from 1987 to 1989 and was Vice President—Finance of Forest Oil Corporation from 1983 to 1987. Mr. Goyanes is also a director of Consort Group Limited, a privately held concern.

Gary R. Petersen has served as a director since June 2001. Mr. Petersen co-founded EnCap Investments L.L.C. (an investment management firm) and has been a Managing Director and principal of the firm since 1988. He had previously served as Senior Vice President and Manager of the Corporate Finance Division of the Energy Banking Group for RepublicBank Corporation. Prior to his position at RepublicBank, he was Executive Vice President and a member of the Board of Directors of Nicklos Oil & Gas Company in Houston, Texas from 1979 to 1984. He served from 1970 to 1971 in the U.S. Army as a First Lieutenant in the Finance Corps and as an Army Officer in the National Security Agency. He is also a director of Nuevo Energy Company and Equus II Incorporated.

John T. Raymond has served as a director since June 2001. Mr. Raymond has served as President, Chief Executive Officer of Plains Resources Inc. since December 2002 and is President and Chief Operating Officer of Plains Exploration and Production. Prior thereto, Mr. Raymond served as Executive Vice President and Chief Operating Officer of Plains Resources from May 2001 to November 2001 and President and Chief Operating

Officer since November 2001. He was Director of Corporate Development of Kinder Morgan, Inc. from January 2000 to May 2001. He served as Vice President of Corporate Development of Ocean Energy, Inc. from April 1998 to January 2000. He was Vice President of Howard Weil Labouisse Friedrichs, Inc. from 1992 to April 1998.

Robert V. Sinnott has served as a director of our general partner or former general partner since September 1998. Mr. Sinnott has been a Senior Managing Director of Kayne Anderson Capital Advisors, L.P. (an investment management firm) since 1996, and was a Managing Director from 1992 to 1996. He is also a vice president of Kayne Anderson Investment Management Inc., the general partner of Kayne Anderson Capital Advisors, L.P. He was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992. He is also a director of Plains Resources and Glacier Water Services, Inc. (a vended water company).

Arthur L. Smith has served as a director of our general partner or former general partner since February 1999. Mr. Smith is Chairman and Chief Executive Officer of John S. Herold, Inc. (an independent petroleum research firm), a position he has held since 1984. For the period from May 1998 to November 1998, he served as Chairman and Chief Executive Officer of Torch Energy Advisors Incorporated. He is also a director of Cabot Oil & Gas Corporation and Evergreen Resources, Inc.

J. Taft Symonds has served as a director since June 2001. He has been Chairman of the Board of Symonds Trust Co. Ltd. (an investment firm) and Chairman of the Board of Maurice Pincoffs Company, Inc. (an international marketing firm) since 1978. He is also Chairman of the Board of Tetra Technologies, Inc. (an oilfield services firm) and a director of Plains Resources.

The following table sets forth certain information with respect to other members of our management team and officers of the general partner of our Canadian operating partnership:

Name	Age	Position with Our General Partner/Canadian General Partner
Management Team/Other Officers:		
A. Patrick Diamond	30	Manager—Special Projects
Lawrence J. Dreyfuss	48	Associate General Counsel and Assistant Secretary; General Counsel and Secretary of PMC (Nova Scotia) Company (the general partner of Plains Marketing Canada, L.P.)
Al Swanson	39	Treasurer
Troy Valenzuela	42	Vice President—Environmental, Health and Safety
Canadian Officers:		
W. David Duckett	48	Executive Vice President of PMC (Nova Scotia) Company
D. Mark Alenius	43	Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Ralph R. Cross	48	Vice President—Business Development of PMC (Nova Scotia) Company
John Kers	55	Vice President—Operations of PMC (Nova Scotia) Company

A. Patrick Diamond has served as Manager—Special Projects since June 2001. In addition, he was Manager—Special Projects of Plains Resources from August 1999 to June 2001. Prior to joining Plains Resources, Mr. Diamond served Salomon Smith Barney Inc. in its Global Energy Investment Banking Group as a Financial Analyst from July 1994 to June 1997 and as an Associate from July 1997 to May 1999.

Lawrence J. Dreyfuss has served as Associate General Counsel and Assistant Secretary of our general partner since June 2001 and held a senior management position in the Law Department since May 1999. In addition, he was a Vice President of Scurlock Permian LLC from 1987 to 1999.

Al Swanson has served as Treasurer since May 2001. In addition, he held several positions at Plains Resources including Treasurer from February 2001 to May 2001 and Director of Treasury from November 2000 to February 2001. Prior to joining Plains Resources, he served as Treasurer of Santa Fe Snyder Corporation from 1999 to October 2000 and in various capacities at Snyder Oil Corporation including Director of Corporate Finance from 1998, Controller—SOCO Offshore, Inc. from 1997, and Accounting Manager from 1992. Mr. Swanson began his career with Apache Corporation in 1986 serving in internal audit and accounting.

Troy Valenzuela has served as Vice President—Environmental, Health and Safety, or EH&S, since July 2002, and has had oversight responsibility for the environmental, safety and regulatory compliance efforts of the partnership and its predecessors for the last 10 years. He was Director of EH&S with Plains Resources from January 1996 to June 2002, and Manager of EH&S from July 1992 to December 1995. Prior to his time with Plains Resources, Mr. Valenzuela spent seven years with Chevron USA Production Company in various EH&S roles.

W. David Duckett has been Executive Vice President of PMC (Nova Scotia) Company since July 2001. Mr. Duckett was previously with CANPET Energy Group Inc. since 1985, where he served in various capacities, including most recently as President, Chief Executive Officer and Chairman of the Board.

D. Mark Alenius has served as Vice President and Chief Financial Officer of PMC (Nova Scotia) Company since November 2002. In addition, Mr. Alenius was Managing Director, Finance of PMC (Nova Scotia) Company from July 2001 to November 2002. Mr. Alenius was previously with CANPET Energy Group Inc. where he served as Vice President, Finance, Secretary and Treasurer, and was a member of the Board of Directors. Mr. Alenius joined CANPET in February 2000. Prior to joining CANPET Energy, Mr. Alenius briefly served as Chief Financial Officer of Bromley-Marr ECOS Inc., a manufacturing and processing company, from January to July 1999. Mr. Alenius was previously with Koch Industries, Inc.'s Canadian group of businesses, where he served in various capacities, including most recently as Vice-President, Finance and Chief Financial Officer of Koch Pipelines Canada, Ltd.

Ralph R. Cross has been Vice President of Business Development of PMC (Nova Scotia) Company since July 2001. Mr. Cross was previously with CANPET Energy Group Inc. since 1992, where he served in various capacities, including most recently as Vice President of Business Development.

John Kers has been Vice President of Operations for PMC (Nova Scotia) Company since November 2001. Mr. Kers was previously with Murphy Oil Co. Ltd. since 1980, where he served in various capacities, including most recently as Manager of Engineering.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities and Exchange Act of 1934 requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2002. Plains Resources filed a late Form 4 for a transaction in 2002, except that each of Messrs. Sinnott and Smith filed an amended Form 4 to correct an otherwise timely filed Form 4.

Reimbursement of Expenses of our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Historically, an allocation was made for overhead associated with officers and employees who divided time between us and Plains Resources. As a result of the General Partner Transition, all of the employees and officers of the general partner devote 100% of their efforts to our business and there are no allocated expenses. See Item 13. "Certain Relationships and Related Transactions."

Item 11. *Executive Compensation*

Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer and the four other most highly compensated executive officers in 2002 (the "Named Executive Officers"). Messrs. Armstrong, Pefanis and Kramer were compensated by Plains Resources prior to July 2001. However, we reimburse our general partner and its affiliates (and, for 2000 and a portion of 2001, we reimbursed our former general partner and its affiliates, which included Plains Resources) for expenses incurred on our behalf, including the costs of officer compensation allocable to us. The Named Executive Officers have also received certain equity-based awards from our general partner and from our former general partner and its affiliates, which awards (other than awards under the Long-Term Incentive Plan) are not subject to reimbursement by us. See "—Long-Term Incentive Plan" and Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties."

		Annual Compensation		
Name and Principal Position	Year	Salary	Bonus	Other Compensation (2)
Greg L. Armstrong	2002	$ 330,000	$ 600,000	$ 11,000(3)
Chairman and CEO	2001	165,000(1)	450,000	(1)(3)
	2000	(1)	(1)	(1)(3)
Harry N. Pefanis	2002	$ 235,000	$ 475,000	$ 11,000(3)
President and COO	2001	117,500(1)	350,000	(1)(3)
	2000	(1)	(1)	(1)(3)
Phillip D. Kramer	2002	$ 200,000	$ 275,000	$ 11,000(3)
Executive V.P. and CFO	2001	100,000(1)	100,000	(1)(3)
	2000	(1)	(1)	(1)(3)
George R. Coiner	2002	$ 200,000	$ 451,000(4)	$ 11,000(3)
Senior Vice President	2001	175,000	431,100(5)	10,500(3)
	2000	175,000	500,700(6)	10,500(3)
Mark F. Shires	2002	$ 175,000	$ 225,000(7)	$ 11,000(3)
Vice President—Operations	2001	173,333	175,000(7)	10,500(3)
	2000	155,000	220,000(7)	10,500(3)

(1) Salary amounts shown for the year 2001 reflect compensation paid by our general partner and reimbursed by us for the last six months of 2001. Until July 2001, Messrs. Armstrong, Pefanis and Kramer were employed and compensated by Plains Resources, which owned our former general partner. We reimbursed Plains Resources for the portion of their compensation allocable to us. In 2001, approximately $218,000, $655,000 and $127,000 was reimbursed to our former general partner and its affiliates for salary and bonus (for the year 2000) for the services of Messrs. Armstrong, Pefanis and Kramer, respectively. For the year 2000, the equivalent amounts were $165,000, $212,000 and $96,000, respectively. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties."

(2) Executive officers have received equity-based awards from our general partner and former general partner and its affiliates. Other than awards under the general partner's Long-Term Incentive Plan, we do not fund these awards. Other than awards to non-employee directors, no awards have vested to date under our Long-Term Incentive Plan. For a description of awards granted to date under the Long-Term Incentive Plan as well as awards under other equity-based plans, see "—Long-Term Incentive Plan" and Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties."

(3) Prior to the General Partner Transition, Plains Resources matched 100% of employees' contribution to its 401(k) Plan (subject to certain limitations in the plan), with such matching contribution being made 50% in cash and 50% in Plains Resources Common Stock (the number of shares for the stock match being based on the market value of the Common Stock at the time the shares were granted). After the General Partner Transition, our general partner matches 100% of employees' contributions to its 401(k) Plan in cash, subject to certain limitations in the plan.

(4) Includes quarterly bonuses aggregating $361,000 and an annual bonus of $90,000. The annual bonus is payable 60% in 2003, 20% in 2004 and 20% in 2005.

(5) Includes quarterly bonuses aggregating $310,100 and an annual bonus of $120,000. The annual bonus is payable 60% in 2002, 20% in 2003 and 20% in 2004.

(6) Includes quarterly bonuses aggregating $300,700 and an annual bonus of $200,000. The annual bonus is payable 60% in 2001, 20% in 2002 and 20% in 2003.

(7) Annual bonus payable 60% in the year after the year earned, then 20% and 20% in each of the two years following.

Employment Contracts and Termination of Employment and Change-in-Control Arrangements

Prior to the consummation of the General Partner Transition, Messrs. Armstrong and Pefanis were employed pursuant to employment agreements with Plains Resources. Both now have employment agreements with our general partner. Mr. Armstrong is employed as Chairman and Chief Executive Officer. The primary term of Mr. Armstrong's employment agreement runs for three years from June 30, 2001. The term will be automatically extended by one year on each anniversary of the initial date (June 30, 2001) unless Mr. Armstrong receives notice from the Chairman of the Compensation Committee that the Board of Directors has elected not to extend the agreement. Mr. Armstrong has agreed, during the term of the agreement and for five years thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provides for a current base salary of $330,000 per year, subject to annual review. If Mr. Armstrong's employment is terminated without cause, he will be entitled to receive an amount equal to his annual base salary plus his highest annual bonus, multiplied by the lesser of (i) the number of years (including fractional years) remaining on the agreement and (ii) two. If Mr. Armstrong terminates his employment as a result of a change in control he will be entitled to receive an amount equal to three times the aggregate of his annual base salary and bonus. Under Mr. Armstrong's agreement, a "change of control" is defined to include (i) the acquisition by an entity or group (other than Plains Resources and its wholly owned subsidiaries) of 50% or more of our general partner or (ii) the existing owners of our general partner ceasing to own more than 50% of our general partner. If Mr. Armstrong's employment is terminated because of his death, a lump sum payment will be paid to his designee equal to his annual salary plus his highest annual bonus, multiplied by the lesser of (i) the number of years (including fractional years) remaining on the agreement and (ii) two. Under the agreement, Mr. Armstrong will be reimbursed for any excise tax due as a result of compensation (parachute) payments.

Mr. Pefanis is employed as President and Chief Operating Officer. The primary term of Mr. Pefanis' employment agreement runs for three years from June 30, 2001. The term will be automatically extended by one year on each anniversary of the initial date (June 30, 2001) unless Mr. Pefanis receives notice from the Chairman of the Board of Directors that the Board has elected not to extend the agreement. Mr. Pefanis has agreed, during the term of the agreement and for one year thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provides for a current base salary of $235,000 per year, subject to annual review. The provisions in Mr. Pefanis' agreement with respect to termination, change in control and related payment obligations are substantially similar to the parallel provisions in Mr. Armstrong's agreement.

Long-Term Incentive Plan

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan for employees and directors of our general partner and its affiliates who perform services for us. The Long-Term Incentive Plan consists of two components, a restricted unit plan and a unit option plan. The Long-Term Incentive Plan currently permits the grant of restricted units and unit options covering an aggregate of 1,425,000 common units. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors in its discretion may terminate the Long-Term Incentive Plan at any time with respect to any common units for which a grant has not yet been made. Our general partner's board of directors also has the right to alter or amend the Long-Term Incentive Plan or any part of the plan from time to time, including increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Restricted Unit Plan. A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. As of February 21, 2003, aggregate outstanding grants of approximately 1,047,000 restricted units have been made to employees, officers and directors of our general partner. The Compensation Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine. Restricted units granted to employees during the subordination period, although additional vesting criteria may sometimes apply, will vest only after, and in the same proportions as, the conversion of the subordinated units to common units. Grants made to non-employee directors of our general partner are eligible to vest prior to termination of the subordination period.

If a grantee terminates employment or membership on the board for any reason, the grantee's restricted units will be automatically forfeited unless, and to the extent, the Compensation Committee provides otherwise. Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, we may issue up to 975,000 common units to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan (see below). If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. Following the subordination period, the Compensation Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units.

The restricted units (other than director grants) will vest only after, and in the same proportion as, any conversion of subordinated units into common units. As discussed below, subordinated units will convert at the end of the subordination period (as defined in the partnership agreement). After conversion of the subordinated units, most of the restricted units are subject to an additional 90-day waiting period before vesting occurs. Certain of the restricted unit grants contain additional vesting requirements tied to the Partnership achieving targeted distribution thresholds, generally $2.10, $2.30 and $2.50 per unit (annualized).

The subordination period (as defined in the partnership agreement) will end if certain financial tests are met for three consecutive four-quarter periods (the "testing period"), but no sooner than December 31, 2003. During the first quarter after the end of the subordination period, all of the subordinated units will convert into common units. Early conversion of a portion of the subordinated units may occur if the testing period is satisfied before December 31, 2003. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook—Vesting of Unit Grants under LTIP and Conversion of Subordinated Units."

Under generally accepted accounting principles, we are required to recognize an expense when the financial tests for conversion of subordinated units and required distribution levels are met. The financial tests involve GAAP accounting concepts as well as complex and esoteric cash receipts and disbursement concepts that are indexed to the minimum quarterly distribution rate of $1.80 per limited partner unit. Because of this complexity, it is difficult to forecast when the vesting of these restricted units will occur. However, at the current annualized distribution level of $2.15 per unit, assuming the subordination conversion test is met, the costs associated with the vesting of up to approximately 845,000 units would be incurred or accrued in the second half of 2003 or the first quarter of 2004. At an annualized distribution level of $2.30 to $2.49, the number of units would be approximately 935,000. At an annualized distribution level at or above $2.50, the number of units would be approximately 1,025,000. Our ability to continue to meet the requirements for conversion and vesting is subject to a number of economic and operational contingencies. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors Related to Our Business" and "Forward Looking Statements."

We are currently planning to issue units to satisfy the first 975,000 vested and delivered (after any units withheld for taxes), and to purchase units in the open market to satisfy any vesting obligations in excess of that amount. Issuance of units would result in a non-cash compensation expense, while a purchase of units would result in a cash charge to compensation expense. In addition, the "company match" portion of payroll taxes, plus the value of any units withheld for taxes, would result in a cash charge. The amount of the charge to expense will depend upon the unit price on the date vesting occurs.

The issuance of the common units pursuant to the restricted unit plan is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration will be paid to us by the plan participants upon receipt of the common units.

In 2000, the three non-employee directors of our former general partner (Messrs. Goyanes, Sinnott and Smith) were each granted 5,000 restricted units. These units vested and were paid in connection with the consummation of the General Partner Transition. Additional grants of 5,000 restricted units were made in 2002 to each non-employee director of our general partner. These units vest and are payable in 25% increments on each anniversary of June 8, 2001. The first vesting took place on June 8, 2002. See "—Compensation of Directors."

The following table shows the restricted units granted to the Named Executive Officers, as well as executive officers and directors as a group.

Name	LTIP Restricted Units(1)	Value as of Fiscal Year End(2)
Greg L. Armstrong	70,000	$ 1,708,000
Harry N. Pefanis	70,000	$ 1,708,000
Phillip D. Kramer	50,000	$ 1,220,000
George R. Coiner	67,500	$ 1,647,000
Mark F. Shires	50,000	$ 1,220,000
Directors and officers as a group	420,000	$ 10,248,000

(1) The units granted to officers will vest only after, and in the same proportion as, any conversion of subordinated units into common units. In addition, with respect to certain of the grants underlying these units, vesting is contingent upon the Partnership achieving specified distribution thresholds. For such grants, 25% of the units have no distribution requirement, 25% require an annualized per unit distribution of $2.10 (already achieved), 25% require an annualized distribution level of $2.30 and 25% require an annualized distribution level of $2.50. These additional vesting conditions apply to 10,000 of the units granted to Mr. Pefanis, 37,500 of the units granted to Mr. Coiner, 20,000 of the units granted to Mr. Shires, all of the units granted to Messrs. Armstrong and Kramer, and 252,500 of the units granted to officers and directors as a group.

(2) Calculated as if vested and delivered, at a market value of $24.40 at the market close, on December 31, 2002.

Unit Option Plan. The Unit Option Plan under our Long-Term Incentive Plan currently permits the grant of options covering common units. No grants have been made under the Unit Option Plan to date. However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant. Unit options granted during the subordination period will become exercisable automatically upon, and in the same proportions as, the conversion of the subordinated units to common units, unless a later vesting date is provided.

Upon exercise of a unit option, our general partner may deliver common units acquired by it in the open market or in private transactions or use common units already owned by our general partner, or any combination of the foregoing. In addition, we may issue up to 975,000 common units to satisfy delivery obligations under the grants, less any common units issued upon vesting of Restricted Units under the Plan. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring such common units and the proceeds received by our general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and our general partner will remit to us the proceeds received by it from the optionee upon exercise of the unit option.

Other Equity Grants

Certain other employees and officers have also received grants of equity not associated with the Long-Term Incentive Plan described above, and for which we have no cost or reimbursement obligations. See Item 13. “Certain Relationships and Related Transactions—Transactions with Related Parties.”

Compensation of Directors

Each director of our general partner who is not an employee of our general partner is paid an annual retainer fee of $30,000, plus reimbursement for out-of-pocket expenses related to meeting attendance. In 2001, Messrs. Goyanes and Smith each received $10,000 for their service on a special committee of the Board of Directors of our former general partner. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. Each committee chairman (other than the Audit Committee) receives $2,000 annually. The chairman of the Audit Committee receives $20,000 annually, and the other members of the Audit Committee receive $11,000 annually.

In 2000, Messrs. Goyanes, Sinnott and Smith, as directors of our former general partner, received a grant of 5,000 restricted units each under our Long-Term Incentive Plan. The restricted units vested and were paid in 2001 in connection with the consummation of the General Partner Transition. Each non-employee director of our general partner received a grant of 5,000 restricted units in 2002. The units vest and are payable in 25% increments annually on each anniversary of June 8, 2001. The first vesting occurred on June 8, 2002.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters***

Beneficial Ownership of Partnership Units

The following table sets forth the beneficial ownership of units held by beneficial owners of 5% or more of the units, by directors and Named Executive Officers of our general partner and by all directors and executive officers as a group as of February 21, 2003.

Name of Beneficial Owner	Common Units	Percentage of Common Units	Class B Common Units	Percentage of Class B Units	Subordinated Units	Percentage of Subordinated Units	Percentage of Total Units
Plains Resources Inc.[1]	6,626,008	17.3%	1,307,190	100.0%	4,471,026[2]	44.60%	25.02%
Plains Holdings Inc.[1]	6,626,008	17.3%	1,307,190	100.0%	4,471,026[2]	44.60%	25.02%
Goldman, Sachs & Co.[3]	2,446,566	6.4%	—	—	—	—	4.1%
Sable Holdings, L.P.[4]	—	—	—	—	1,943,423	19.40%	3.92%
KAFU Holdings, L.P.[5]	—	—	—	—	1,595,322	15.90%	3.22%
E-Holdings III, L.P.[6]	—	—	—	—	874,540	8.70%	1.76%
Greg L. Armstrong	102,606[7]	[8]	—	—	47,343[9]	[8]	[8]
Harry N. Pefanis	72,975[7]	[8]	—	—	18,352[9]	[8]	[8]
George R. Coiner	44,026[7]	[8]	—	—	10,625[9]	[8]	[8]
Phillip D. Kramer	30,500[7]	[8]	—	—	20,992[9]	[8]	[8]
Mark F. Shires	—[7]	—	—	—	5,000	[8]	—
Everardo Goyanes	5,600	[8]	—	—	—	—	[8]
Gary R. Petersen[6]	1,350	[8]	—	—	—	—	[8]
John T. Raymond	1,250	—	—	—	97,171[10]	[8]	[8]
Robert V. Sinnott[5]	11,250	[8]	—	—	—	—	[8]
Arthur L. Smith	11,250	[8]	—	—	—	—	[8]
J. Taft Symonds	11,250	[8]	—	—	—	—	[8]
All directors and executive officers as a group (14 persons)	293,724[7]	[8]	—	—	217,229[9]	2.20%	1.03%

(1) Plains Resources Inc. is the sole stockholder of Plains Holdings Inc, our former general partner. The record holder of the Class B Common Units is Plains Holdings Inc. The record holder of the common units and subordinated units is Plains Holdings LLC, a wholly owned subsidiary of Plains Holdings Inc. The address of Plains Resources Inc., Plains Holdings Inc. and Plains Holdings LLC is 500 Dallas, Suite 700, Houston, Texas 77002.

(2) Includes 14,104 subordinated units owned by Plains Resources, to be transferred to certain of our employees (former Plains Resources employees), subject to certain vesting conditions. See "Certain Relationships and Related Transactions—Transactions with Related Parties—Stock Option Replacement."

(3) The address for Goldman, Sachs & Co. and its parent, the Goldman Sachs Group, Inc., is 85 Broad Street, New York, New York 10004. Goldman, Sachs & Co., a broker/dealer, and its parent, the Goldman Sachs Group, Inc., are deemed to have shared voting power and shared disposition power over 2,446,566 common units owned by their customers.

(4) Subordinated Units include 97,171 units contributed to Sable Holdings, L.P. by John T. Raymond in exchange for a limited partner interest. Mr. Raymond has the right to reacquire such units. Sable Holdings, L.P. is controlled by James M. Flores. Mr. Flores is the Executive Chairman of Plains Resources and the Chairman and Chief Executive Officer of Plains Exploration & Production Co. The address for Sable Holdings, L.P. is 500 Dallas, Suite 700, Houston, Texas 77002.

(5) The general partner of KAFU Holdings, L.P. is Kayne Anderson Capital Advisors, the general partner of which is Kayne Anderson Investment Management, Inc., of which Robert V. Sinnott is a Vice President. Mr. Sinnott disclaims any deemed beneficial ownership of units held by KAFU Holdings, L.P. Mr. Sinnott owns a 4.5% limited partner interest in KAFU Holdings, L.P. The address for KAFU Holdings, L.P. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(6) E-Holdings III, L.P. is an affiliate of EnCap Investments L.L.C. of which Gary R. Petersen is a Managing Director. Mr. Petersen disclaims any deemed beneficial ownership of units owned by E-Holdings III, L.P. The address for E-Holdings III, L.P. is 1100 Louisiana, Suite 3150, Houston, Texas 77002.

(7) Does not include units granted under the Long-Term Incentive Plan, none of which will vest within 60 days of the date hereof. See Item 11. "Executive Compensation—Long-Term Incentive Plan."

(8) Less than one percent.

(9) Includes the following vested, unexercised options to purchase subordinated units. Mr. Armstrong: 18,750; Mr. Pefanis: 13,750; Mr. Coiner: 10,625; Mr. Kramer: 11,250; Mr. Shires: 5,000; directors and officers as a group: 66,875. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—Performance Option Plan."

(10) Units contributed to Sable Holdings, L.P. in exchange for an indirect limited partner interest. Mr. Raymond has the right to reacquire such units. See Note (4) above.

Beneficial Ownership of General Partner Interest

Plains AAP, L.P. owns all of our 2% general partner interest and all of our incentive distribution rights. The effective ownership of Plains AAP, L.P. (after giving effect to proportionate ownership of its 1% general partner, Plains All American GP LLC) is as follows: Plains Holdings Inc.—44%; Sable Investments, L.P.—20%; KAFU Holdings, L.P.—16.418%; E-Holdings III, L.P.—9%; PAA Management, L.P.—4%; First Union Investors, Inc.—3.382%; Mark E. Strome—2.134%; and Strome Hedgecap Fund, L.P.—1.066%. In addition, John T. Raymond has the right to acquire a 1% interest in the general partner interest from Sable Investments, L.P.

PAA Management, L.P. is owned by certain members of senior management, including Messrs. Armstrong, Pefanis, Kramer, Coiner and Shires.

Equity Compensation Plan Information

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans
Equity compensation plans approved by unitholders:			
1998 Long Term Incentive Plan	975,000 (1)	N/A(2)	0
Equity compensation plans not approved by unit holders:			
1998 Long Term Incentive Plan	(1)(3)	N/A(2)	(4)
Performance Option Plan	(5)	$ 19.07(6)	(7)

(1) Our general partner has adopted and maintains a Long Term Incentive Plan for our officers, employees and directors. See Item 11. "Executive Compensation—Long-Term Incentive Plan." As originally instituted by our former general partner prior to our IPO, the LTIP contemplated awards of up to 975,000 units. Upon vesting, these awards could be satisfied either by (i) primary issuance of units by us or (ii) purchase of units by our general partner with the cost reimbursed by us. In 2000, the LTIP was amended, as provided in the plan, without unitholder approval to increase the maximum awards to 1,425,000 units; however, we can issue no more than 975,000 units to satisfy the awards. Any additional units must be purchased by our general partner and reimbursed by us.

(2) Restricted unit awards under the LTIP vest without payment by recipients. See Item 11. "Executive Compensation—Long-Term Incentive Plan—Restricted Unit Plan."

(3) Although awards for approximately 72,000 units are outstanding under the portion of the LTIP not approved by unitholders, all of these awards must be satisfied out of units purchased by our general partner and reimbursed by us. None will be satisfied by "units issued upon exercise/vesting."

(4) Awards for approximately 355,500 additional units may be granted under the portion of the LTIP not approved by unitholders; however, none are "available for future issuance." All awards must be satisfied out of units purchased by our general partner and reimbursed by us.

(5) Our general partner has adopted and maintains a Performance Option Plan for officers and key employee pursuant to which optionees have the right to purchase subordinated units from the general partner, up to the 450,000 units available under the plan. The subordinated units that will be sold under the plan were contributed to the general partner by certain of its owners. Thus, there will be no units "issued upon exercise/vesting of outstanding options." Approximately 375,000 unit options have been granted under the plan. See Item 13. "Certain Relationships and Related Parties—Performance Option Plan."

(6) The current strike price for all outstanding options under the plan is $19.07 per subordinated unit. The strike price decreases as distributions are paid. Future grants may include different pricing elements. See Item 13. "Certain Relationships and Related Parties—Performance Option Plan."

(7) The general partner owns 450,000 subordinated units contributed by the general partner's investors to fund the plan. Approximately 75,000 units are not subject to existing option grants.

Item 13. *Certain Relationships and Related Transactions*

Our General Partner

Our operations and activities are managed by, and our officers and personnel are employed by, our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). Prior to the consummation of the General Partner Transition, some of the senior executives who managed our business also managed and operated the business of Plains Resources. The transition of employment of such executives to our general partner was effected on June 30, 2001. We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf.

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 ($1.80 annualized) per unit, 25% of the amounts we distribute in excess of $0.495 ($1.98 annualized) per unit and 50% of amounts we distribute in excess of $0.675 ($2.70 annualized) per unit. The following table illustrates the allocation of aggregate distributions at different per-unit levels:

Annual Distribution Per Unit	Distribution to Unitholders(1)(2)	Distribution to GP(1)(2)(3)	Total Distribution(1)	GP Percentage of Total Distribution
$1.80	$ 90,000	$ 1,837	$ 91,837	2.0%
$2.00	$100,000	$ 3,758	$103,758	3.6%
$2.20	$110,000	$ 7,092	$117,092	6.1%
$2.40	$120,000	$10,425	$130,425	8.0%
$2.60	$130,000	$13,758	$143,758	9.6%
$2.80	$140,000	$20,425	$160,425	12.7%
$3.00	$150,000	$30,425	$180,425	16.9%

(1) In thousands.
(2) Assumes 50,000,000 units outstanding. Actual number of units outstanding as of the date hereof are 49,577,748. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner of any given level of distribution per unit.
(3) Includes distributions attributable to the 2% general partner interest and the incentive distribution rights.

Transactions with Related Parties

General

Before the General Partner Transition, Plains Resources indirectly owned and controlled our former general partner interest. In 2001, our former general partner and its affiliates incurred $31.2 million of direct and indirect expenses on our behalf, which we reimbursed. Of this amount, approximately $218,000, $655,000 and $127,000 represented allocated salary and bonus (for the year 2000) reimbursement for the services of Messrs. Armstrong, Pefanis and Kramer, respectively, as officers of our former general partner. In the year 2000, we reimbursed our former general partner $63.8 million, of which $165,000, $212,000 and $96,000 were allocated for Messrs. Armstrong, Pefanis and Kramer.

Plains Resources currently owns an effective 44% of our general partner interest. We have ongoing relationships with Plains Resources. These relationships include but are not limited to:

- a separation agreement entered into in connection with the General Partner Transition pursuant to which (i) Plains Resources has indemnified us for (a) claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on alleged acts or omissions occurring on or prior to June 8, 2001, or (b) claims related to the upstream business, whenever arising, and (ii) we have indemnified Plains Resources for claims related to the midstream business, whenever arising. Plains Resources also has agreed to indemnify and maintain liability insurance for the individuals who were, on or before June 8, 2001, directors or officers of Plains Resources or our former general partner.
- a Pension and Employee Benefits Assumption and Transition Services Agreement that provided for the transfer to our general partner of the employees of our former general partner and certain headquarters employees of Plains Resources.
- an Omnibus Agreement that provides for the resolution of certain conflicts arising from the fact that we and Plains Resources conduct related businesses;
- a Marketing Agreement with Plains Resources that provides for the marketing of Plains Resources' equity crude oil production (including its subsidiaries that conduct exploration and production

activities.). Under the Marketing Agreement, we purchase for resale at market prices all of Plains Resources equity production for a fee of $0.20 per barrel. The Marketing Agreement will terminate upon a "change of control" of Plains Resources or our general partner. The fee is subject to adjustment every three years based on then-existing market conditions. For the year ended December 31, 2002, Plains Resources produced approximately 30,700 barrels per day that were subject to the Marketing Agreement. We paid approximately $247.7 million for such production and recognized gross margin of approximately $1.8 million under the terms of that agreement. In our opinion, these purchases were made at prevailing market prices. In November 2001, the agreement automatically extended for an additional three-year period. On December 18, 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production ("PXP") to its shareholders. PXP is a successor participant to this marketing agreement; and

- a Letter Agreement with Stocker Resources, L.P. (now PXP) that provides that if the Marketing Agreement terminates before our crude oil sales agreement with Tosco Refining Co. terminates, PXP will continue to sell and we will continue to purchase PXP's equity crude oil production from the Arroyo Grande field (now owned by a subsidiary of PXP) under the same terms as the Marketing Agreement until our Tosco sales agreement terminates.

Transaction Grant Agreements

In connection with our initial public offering, our former general partner, at no cost to us, agreed to transfer, subject to vesting, approximately 400,000 of its affiliates' common units (including distribution equivalent rights attributable to such units) to certain key officers and employees of our former general partner and its affiliates. Of this amount, 75,000 common units were allocated to each of Messrs. Armstrong and Pefanis, 50,000 common units were allocated to Mr. Coiner and 30,000 were allocated to Mr. Kramer. Under these grants, the common units vested based on attaining a targeted operating surplus for a given year. Of the 400,000 units subject to the transaction grant agreements, 69,444 units vested in 2000 for 1999's operating results and 133,336 units vested in 2001 for 2000's operating results. The remainder (197,220 units) vested in connection with the consummation of the General Partner Transition. Distribution equivalent rights were paid in cash at the time of the vesting of the associated common units. The values of the units and associated distribution equivalent rights that vested under the Transaction Grant Agreements for all grantees in 2001, 2000 and 1999 were $5.7 million, $3.1 million and $1.0 million respectively. Although we recorded noncash compensation expenses with respect to these vestings, the compensation expense incurred in connection with these grants was funded by our former general partner, without reimbursement by us.

Long-Term Incentive Plan

Our general partner has adopted the Plains All American LLC 1998 Long-Term Incentive Plan for employees and directors of our general partner and its affiliates who perform services for us. The Long-Term Incentive Plan consists of two components, a restricted unit plan and a unit option plan. The Long-Term Incentive Plan currently permits the grant of restricted units and unit options covering an aggregate of 1,425,000 common units. The plan is administered by the Compensation Committee of our general partner's board of directors.

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. As of February 21, 2003, aggregate outstanding grants of approximately 1,047,000 restricted units have been made to employees, officers and directors of our general partner. See Item 11. "Executive Compensation—Long-Term Incentive Plan."

Performance Option Plan

In connection with the General Partner Transition, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 375,000 units have been granted. Of this amount, 75,000, 55,000, 45,000, 42,500 and 20,000 were granted to Messrs. Armstrong, Pefanis, Kramer, Coiner and Shires, respectively, and approximately 278,000 to executive officers as a group. Such options vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The first such level was reached, and 25% of the options vested, in 2002. The options will vest in their entirety immediately upon a change in control (as defined in the grant agreements). The original purchase price under the options was $22 per subordinated unit, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of February 21, 2003, the purchase price was $19.07 per unit. The terms of future grants may differ from the existing grants. Because the subordinated units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options.

Stock Option Replacement

In connection with the General Partner Transition, certain members of the management team that had been employed by Plains Resources were transferred to the general partner. At that time, such individuals held in-the-money but unvested stock options in Plains Resources, which were subject to forfeiture because of the transfer of employment. Plains Resources, through its affiliates, agreed to substitute a contingent grant of subordinated units with a value equal to the spread on the unvested options. Approximately 51,000 subordinated units were subject to such grants, with 34,511 granted to executive officers, including 8,548, 4,602 and 9,742 to Messrs. Armstrong, Pefanis and Kramer. The subordinated units vest on the same schedule as the stock options would have vested. The units granted to Messrs. Armstrong, Pefanis and Kramer vested in their entirety in 2002. The general partner administers the vesting and delivery of the units under the grants. Because the units necessary to satisfy the delivery requirements under the grants are provided by Plains Resources, we have no obligation to reimburse the general partner for the cost of such units.

Tank Car Lease and CANPET

In connection with the CANPET asset acquisition, Plains Marketing Canada, L.P. assumed CANPET's rights and obligations under a Master Railcar Leasing Agreement between CANPET and Pivotal Enterprises Corporation ("Pivotal"). The agreement provides for Plains Marketing Canada, L.P. to lease approximately 57 railcars from Pivotal at a lease price of $1,000 (Canadian) per month, per car. The lease extends until June of 2008, with an option for Pivotal to extend the term of the lease for an additional five years. Pivotal is substantially owned by former employees of CANPET, including W. David Duckett, who is the Executive Vice President of PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P. Mr. Duckett owns a 22% interest in Pivotal. Mr. Duckett, as an owner of CANPET, will also receive a portion of the proceeds from any contingent payment of purchase price for the CANPET assets. See Items 1 and 2. "Business and Properties—Major Acquisitions and Dispositions—CANPET Energy Group, Inc."

Other

Goldman, Sachs & Co., which owns approximately 6% of our common units, was the lead underwriter for our August 2002 offering of units. The total underwriting commissions paid in connection with this offering were approximately $6.3 million.

Item 14. *Controls and Procedures*

In connection with our periodic reporting under the Exchange Act, we have established "disclosure controls and procedures," which we refer to as our "DCP". Management (including our Chief Executive Officer and Chief Financial Officer) has evaluated the effectiveness of the design and operation of our DCP within the last 90 days, and has found our DCP to be effective in producing the timely recording, processing, summarization and reporting of information, and in accumulating and communicating such information to management to allow for timely decisions with regard to required disclosure.

There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the last date of their evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

We have recently commenced an effort to consolidate our various internal auditing activities into a centralized function, and hired a director of internal auditing in September 2002 to oversee that function. As we consolidate these activities, we will make any additional enhancements to our controls and procedures that are deemed appropriate.

Our Chief Executive Officer and Chief Financial Officer have furnished their certifications pursuant to 18 U.S.C. § 1350 to the SEC as correspondence in connection with the filing of this report.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

(a) (1) and (2) Financial Statements and Financial Statement Schedules

See "Index to the Consolidated Financial Statements" set forth on Page F-1.

All schedules are omitted because they are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(a) (3) Exhibits

3.1	—Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 27, 2001).
3.2	—Second Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.2 to Form 8-K filed August 27, 2001).
3.3	—Second Amended and Restated Agreement of Limited Partnership of All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.3 Form 8-K filed August 27, 2001).
3.4	—Certificate of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.4 to Registration Statement, file No. 333-64107).
3.5	—Certificate of Limited Partnership of Plains Marketing, L.P. dated as of November 10, 1998 (incorporated by reference to Exhibit 3.5 to Annual Report on Form 10-K for the Year Ended December 31, 1998).
3.6	—Articles of Conversion of All American Pipeline Company dated as of November 10, 1998 (incorporated by reference to Exhibit 3.5 to Annual Report on Form 10-K for the Year Ended December 31, 1998).
3.7	—Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated as of June 8, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed June 11, 2001).
3.8	—Amended and Restated Limited Liability Company Agreement of Plains All American GP, LLC dated as of June 8, 2001 (incorporated by reference to Exhibit 3.2 to Form 8-K filed June 11, 2001).
4.1	—Registration Rights Agreement, dated as of June 8, 2001, among Plains All American Pipeline, L.P., Sable Holdings, L.P., E-Holdings III, L.P., KAFU Holdings, LP, PAA Management, L.P., Mark E. Strome, Strome Hedgecap Fund, L.P., John T. Raymond and Plains All American Inc. (incorporated by reference to Exhibit 4.1 to Form 8-K filed June 11, 2001).
4.2	—Indenture dated as of September 25, 2002 (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002).
4.3	—First Supplemental Indenture dated as of September 25, 2002 (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002).
4.4	—Registration Rights Agreement dated September 25, 2002 (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002).
10.01	—Contribution, Assignment and Amendment Agreement, dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 27, 2001).
10.02	—Contribution, Assignment and Amendment Agreement, dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 11, 2001).

10.03	—Separation Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to Form 8-K filed June 11, 2001.
10.04	—Pension and Employee Benefits Assumption and Transition Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to Form 8-K filed June 11, 2001).
**10.05	—Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920).
**10.06	—Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to Registration Statement on Form S-8, File No. 333-74920).
**10.07	—Phantom MLP unit Agreement for Greg L. Armstrong (incorporated by reference to Exhibit 99.3 to Registration Statement on Form S-8, File No. 333-74920).
**10.08	—Phantom MLP Unit Agreement for Phillip D. Kramer (incorporated by reference to Exhibit 99.5 to Registration Statement on Form S-8, File No. 333-74920).
**10.09	—Phantom MLP Unit Agreement for Tim Moore (incorporated by reference to Exhibit 99.6 to Registration Statement on Form S-8, File No. 333-74920).
**10.10	—Phantom MLP Unit Agreement for Harry N. Pefanis (incorporated by reference to Exhibit 99.7 to Registration Statement on Form S-8, File No. 333-74920).
**10.11	—Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2001).
**10.12	—Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2001).
10.13	—Asset Purchase and Sale Agreement between Murphy Oil Company Ltd. And Plains Marketing Canada, L.P. (incorporated by reference to Form 8-K filed May 10, 2001.
10.14	—Crude Oil Marketing Agreement among Plains Resources Inc., Plains Illinois Inc., Stocker Resources, L.P., Calumet Florida, Inc. and Plains Marketing, L.P. dated as of November 23, 1998 (incorporated by reference to Exhibit 10.07 to Annual Report on Form 10-K for the Year Ended December 31, 1998).
10.15	—Omnibus Agreement among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., and Plains All American Inc. dated as of November 23, 1998 (incorporated by reference to Exhibit 10.08 to Annual Report on Form 10-K for the Year Ended December 31, 1998).
10.16	—Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to Registration Statement, file No. 333-64107).
10.17	—Transportation Agreement dated August 2, 1993, between All American Pipeline Company and Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to Registration Statement, File No. 333-64107).
10.18	—First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to Annual Report on Form 10-K for the Year Ended December 31, 1998).

10.19 —Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to Annual Report on Form 10-K for the Year Ended December 31, 1998).

10.20 —Asset Sales Agreement between Chevron Pipe Line Company and Plains Marketing, L.P. dated as of April 16, 1999 (incorporated by reference to Exhibit 10.17 to Quarterly Report on Form 10-Q for the Quarter Ended March 31, 1999).

10.21 —Pipeline Sale and Purchase Agreement dated January 31, 2000, among Plains All American Pipeline, L.P., All American Pipeline, L.P., El Paso Natural Gas Company and El Paso Pipeline Company (incorporated by reference to Exhibit 10.27 to Annual Report on Form 10-K for the Year Ended December 31, 1999).

10.22 —Second Amended and Restated Agreement [Revolving Credit Facility] dated July 2, 2002, among Plains Marketing, L.P., All American Pipeline, L.P., Plains All American Pipeline, L.P., and Fleet National Bank and certain other lenders (incorporated by reference to Exhibit 10.01 to the Quarterly Report on Form 10-Q for the Quarter ended June 30, 2002).

10.23 —Second Amended and Restated Agreement [Letter of Credit and Hedged Inventory Facility] dated July 2, 2002, among Plains Marketing, L.P., All American Pipeline, L.P., Plains All American Pipeline, L.P., and Fleet National Bank and certain other lenders (incorporated by reference to Exhibit 10.02 to the Quarterly Report on Form 10-Q for the Quarter ended June 30, 2002).

10.24 —Purchase and Sale Agreement, effective May 2, 2002 by and between Shell Pipeline Company LP, Equilon Enterprises LLC and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 99.4 to Current Report on Form 8-K dated August 1, 2002).

*21.1 —Subsidiaries of the Registrant.

*23.1 —Consent of PricewaterhouseCoopers LLP.

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* Filed herewith

** Management contract or compensatory plan or arrangement

(b) Reports on Form 8-K

A Current Report on Form 8-K was furnished on February 26, 2003, in connection with disclosure of first quarter estimates and earnings guidance.

A Current Report on Form 8-K was filed on November 15, 2002, including as an exhibit pro forma financial statements, in connection with the registration of $200 million of 7.75% senior notes.

A Current Report on Form 8-K was filed on November 8, 2002, including as an exhibit the balance sheet of Plains AAP, L.P. as of June 30, 2002.

A Current Report on Form 8-KA was furnished on November 5, 2002, to correct certain information in the October 29, 2002, 8-K.

A Current Report on Form 8-K was furnished on October 29, 2002, in connection with disclosure of fourth quarter estimates and earnings guidance.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PLAINS AAP, L.P.,
its general partner

By: PLAINS ALL AMERICAN GP LLC,
its general partner

Date: February 28, 2003

By: /S/ GREG L. ARMSTRONG

Greg L. Armstrong, Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)

Date: February 28, 2003

By: /S/ PHILLIP D. KRAMER

Phillip D. Kramer, Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial and Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/S/ GREG L. ARMSTRONG **Greg L. Armstrong**	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	Date: February 28, 2003
/S/ HARRY N. PEFANIS **Harry N. Pefanis**	President and Chief Operating Officer of Plains All American GP LLC	Date: February 28, 2003
/S/ PHILLIP D. KRAMER **Phillip D. Kramer**	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial and Accounting Officer)	Date: February 28, 2003
/S/ EVERARDO GOYANES **Everardo Goyanes**	Director of Plains All American GP LLC	Date: February 28, 2003
/S/ GARY R. PETERSEN **Gary R. Petersen**	Director of Plains All American GP LLC	Date: February 28, 2003
/S/ JOHN T. RAYMOND **John T. Raymond**	Director of Plains All American GP LLC	Date: February 28, 2003
/S/ ROBERT V. SINNOTT **Robert V. Sinnott**	Director of Plains All American GP LLC	Date: February 28, 2003
/S/ ARTHUR L. SMITH **Arthur L. Smith**	Director of Plains All American GP LLC	Date: February 28, 2003
/S/ J. TAFT SYMONDS **J. Taft Symonds**	Director of Plains All American GP LLC	Date: February 28, 2003

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Greg L. Armstrong, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 28, 2003

/s/ GREG L. ARMSTRONG

Greg L. Armstrong
Chief Executive Officer

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Phillip D. Kramer, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 28, 2003

/s/ PHILLIP D. KRAMER

Phillip D. Kramer
Chief Financial Officer

PLAINS ALL AMERICAN PIPELINE, L.P.

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors of the General Partner and the Unitholders of
Plains All American Pipeline, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners' capital, of comprehensive income and of changes in accumulated other comprehensive income (loss) present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries (the "Partnership") at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Partnership changed its method of accounting for derivative instruments and hedging activities effective January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
February 26, 2003

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	December 31, 2002	December 31, 2001
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 3,501	$ 3,511
Accounts receivable, net	499,909	357,619
Inventory	81,849	188,874
Other current assets	17,676	8,078
Total current assets	602,935	558,082
PROPERTY AND EQUIPMENT	1,030,303	653,050
Accumulated depreciation	(77,550)	(48,131)
	952,753	604,919
OTHER ASSETS		
Pipeline linefill	62,558	57,367
Other, net	48,329	40,883
	$ 1,666,575	$ 1,261,251
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 488,922	$ 372,889
Due to related parties	23,301	13,685
Short-term debt and current portion of long-term debt	99,249	104,482
Other current liabilities	25,777	14,104
Total current liabilities	637,249	505,160
LONG-TERM LIABILITIES		
Long-term debt under credit facilities	310,126	351,677
Senior notes, net of unamortized discount of $390	199,610	—
Other long-term liabilities and deferred credits	7,980	1,617
Total liabilities	1,154,965	858,454
COMMITMENTS AND CONTINGENCIES (Note 14)		
PARTNERS' CAPITAL		
Common unitholders (38,240,939 and 31,915,939 units outstanding at December 31, 2002 and 2001, respectively)	524,428	408,562
Class B Common unitholder (1,307,190 units outstanding at each date)	18,463	19,534
Subordinated unitholders (10,029,619 units outstanding at each date)	(47,103)	(38,891)
General partner	15,822	13,592
	511,610	402,797
	$ 1,666,575	$ 1,261,251

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Year Ended December 31,		
	2002	**2001**	**2000**
REVENUES	$ 8,384,223	$ 6,868,215	$ 6,641,187
COST OF SALES AND OPERATIONS	8,209,932	6,720,970	6,506,504
UNAUTHORIZED TRADING LOSSES AND RELATED EXPENSES (Note 3)	—	—	6,963
INVENTORY VALUATION ADJUSTMENT (Note 2)	—	4,984	—
Gross Margin	174,291	142,261	127,720
EXPENSES			
General and administrative	45,663	46,586	40,821
Depreciation and amortization	34,068	24,307	24,523
Total expenses	79,731	70,893	65,344
OPERATING INCOME	94,560	71,368	62,376
Interest expense	(29,057)	(29,082)	(28,691)
Gains on sales of assets (Note 5)	—	984	48,188
Interest and other income (expense), net (Note 10)	(211)	401	10,776
Income before extraordinary item and cumulative effect of accounting change	65,292	43,671	92,649
Extraordinary item (Note 10)	—	—	(15,147)
Cumulative effect of accounting change (Note 2)	—	508	—
NET INCOME	$ 65,292	$ 44,179	$ 77,502
NET INCOME—LIMITED PARTNERS	$ 60,912	$ 42,239	$ 75,754
NET INCOME—GENERAL PARTNER	$ 4,380	$ 1,940	$ 1,748
BASIC AND DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Income before extraordinary item and cumulative effect of accounting change	$ 1.34	$ 1.12	$ 2.64
Extraordinary item	—	—	(0.44)
Cumulative effect of accounting change	—	0.01	—
Net income	$ 1.34	$ 1.13	$ 2.20
WEIGHTED AVERAGE UNITS OUTSTANDING	45,546	37,528	34,386

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2002	**2001**	**2000**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 65,292	$ 44,179	$ 77,502
Items not affecting cash flows from operating activities:			
Depreciation and amortization	34,068	24,307	24,523
Gains on sales of assets (Note 5)	—	(984)	(48,188)
Cumulative effect of accounting change	—	(508)	—
Noncash compensation expense	—	5,741	3,089
Allowance for doubtful accounts	146	3,000	5,000
Inventory valuation adjustment	—	4,984	—
Other noncash items	(242)	(207)	4,574
Change in assets and liabilities, net of acquisitions:			
Accounts receivable and other	(136,481)	(18,856)	120,497
Inventory	105,944	(117,878)	(11,954)
Pipeline linefill	(11,060)	(13,736)	(16,679)
Accounts payable and other current liabilities	106,065	46,671	(161,543)
Due to related party	8,962	(7,266)	(21,741)
Other long-term liabilities and deferred credits	1,200	600	(8,591)
Net cash provided by (used in) operating activities	173,894	(29,953)	(33,511)
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisitions (Note 4)	(324,628)	(229,162)	—
Additions to property and equipment	(40,590)	(21,069)	(12,603)
Net proceeds from sale of property and equipment (Note 5)	1,437	740	223,604
Net cash provided by (used in) investing activities	(363,781)	(249,491)	211,001
CASH FLOWS FROM FINANCING ACTIVITIES			
Net proceeds from issuance of units (Note 8)	145,046	227,549	—
Costs incurred in connection with financing arrangements	(5,435)	(6,351)	(6,748)
Proceeds from the issuance of senior notes	199,600	—	—
Payments on subordinated notes—general partner	—	—	(114,000)
Net borrowings (repayments) on long-term revolving credit facility	(42,144)	34,677	9,900
Net borrowings (repayments) on short-term letter of credit and hedged inventory facility	(4,770)	99,583	(57,419)
Principal payments on senior secured term loans	(3,000)	—	—
Distributions paid to unitholders and general partner	(99,841)	(75,929)	(59,565)
Net cash provided by (used in) financing activities	189,456	279,529	(227,832)
Effect of translation adjustment on cash	421	—	—
Net increase (decrease) in cash and cash equivalents	(10)	85	(50,342)
Cash and cash equivalents, beginning of year	3,511	3,426	53,768
Cash and cash equivalents, end of year	$ 3,501	$ 3,511	$ 3,426
Cash paid for interest, net of amounts capitalized	$ 28,550	$ 33,341	$ 29,292

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL

(in thousands)

	Common Unitholders		Class B Common Unitholders		Subordinated Unitholders		General Partner	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Amount	Amount
Balance at December 31, 1999	23,049	$208,359	1,307	$ 20,548	10,030	$(35,621)	$ (313)	$192,973
Noncash compensation expense	—	—	—	—	—	—	3,089	3,089
Net income	—	50,780	—	2,878	—	22,096	1,748	77,502
Distributions	—	(42,066)	—	(2,384)	—	(13,791)	(1,324)	(59,565)
Balance at December 31, 2000	23,049	217,073	1,307	21,042	10,030	(27,316)	3,200	213,999
Issuance of units	8,867	222,032	—	—	—	—	5,517	227,549
Noncash compensation expense	—	—	—	—	—	—	5,741	5,741
Net income	—	29,436	—	1,476	—	11,327	1,940	44,179
Distributions	—	(51,271)	—	(2,549)	—	(19,558)	(2,551)	(75,929)
Other comprehensive loss	—	(8,708)	—	(435)	—	(3,344)	(255)	(12,742)
Balance at December 31, 2001	31,916	408,562	1,307	19,534	10,030	(38,891)	13,592	402,797
Issuance of units	6,325	142,013	—	—	—	—	3,033	145,046
Net income	—	45,857	—	1,736	—	13,319	4,380	65,292
Distributions	—	(70,821)	—	(2,762)	—	(21,188)	(5,070)	(99,841)
Other comprehensive loss	—	(1,183)	—	(45)	—	(343)	(113)	(1,684)
Balance at December 31, 2002	38,241	$524,428	1,307	$ 18,463	10,030	$(47,103)	$15,822	$511,610

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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

(in thousands)

Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2002	2001	2000
Net income	$ 65,292	$ 44,179	$ 77,502
Other comprehensive loss	(1,684)	(12,742)	—
Total comprehensive income	$ 63,608	$ 31,437	$ 77,502

Consolidated Statement of Changes in Accumulated Other Comprehensive Income (Loss)

	Net Deferred Loss on Derivative Instruments	Currency Translation Adjustments	Total
Balance at December 31, 2000	$ —	$ —	$ —
Cumulative effect of accounting change	(8,337)	—	(8,337)
Reclassification adjustments for settled contracts	(2,526)	—	(2,526)
Changes in fair value of outstanding hedge portion	6,123	—	6,123
Currency translation adjustment	—	(8,002)	(8,002)
Balance at December 31, 2001	$ (4,740)	$ (8,002)	$ (12,742)
Current year activity			
Reclassification adjustments for settled contracts	797	—	797
Changes in fair value of outstanding hedge positions	(4,264)	—	(4,264)
Currency translation adjustment	—	1,783	1,783
Total current year activity	(3,467)	1,783	(1,684)
Balance at December 31, 2002	$ (8,207)	$ (6,219)	$ (14,426)

The accompanying notes are an integral part of these consolidated financial statements.

Note 1—Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. is a publicly traded Delaware limited partnership (the "Partnership") engaged in interstate and intrastate marketing, transportation and terminalling of crude oil and liquefied petroleum gas ("LPG"). We were formed in September 1998 to acquire and operate the midstream crude oil business and assets of Plains Resources Inc. and its wholly-owned subsidiaries ("Plains Resources") as a separate, publicly traded master limited partnership. We completed our initial public offering ("IPO") in November 1998. Immediately after our IPO, Plains Resources owned 100% of our general partner interest and an overall effective ownership in the Partnership of 57% (including the 2% general partner interest and common and subordinated units owned by such entity). As discussed below, Plains Resources' effective ownership interest in the Partnership has since been reduced substantially.

In May 2001, senior management of our general partner and a group of financial investors entered into a transaction with Plains Resources to acquire majority control of our general partner and a majority of the outstanding subordinated units. The transaction closed in June 2001, and for purposes of this report is referred to as the "General Partner Transition." As a result of this transaction and subsequent equity offerings, Plains Resources' overall effective ownership has been reduced to approximately 25%.

The general partner interest is now held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Plains All American GP LLC manages our operations and activities and employs our officers and personnel. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. We use the phrase "former general partner" to refer to the subsidiary of Plains Resources that formerly held the general partner interest.

Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., All American Pipeline, L.P. and Plains Marketing Canada, L.P., and are concentrated in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2002 and 2001, and the consolidated results of our operations, cash flows, changes in partners' capital and comprehensive income (loss) for the years ended December 31, 2002, 2001 and 2000, and changes in accumulated other comprehensive income for the years ended December 31, 2002 and 2001. All significant intercompany transactions have been eliminated. Certain reclassifications were made to prior period amounts to conform with the current period presentation.

Note 2—Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates we make include: (1) estimated useful lives of assets, which impacts depreciation and amortization, (2) allowance for doubtful accounts receivable, (3) accruals related to revenues and expenses including mark-to-market estimates pursuant to Statement of Financial Accounting

Standards ("SFAS") No. 133 "Accounting For Derivative Instruments and Hedging Activities", as amended, (4) liability and contingency accruals, and (5) estimated fair value of assets and liabilities acquired and identification of associated intangible assets as well as transaction related costs. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Gathering and marketing revenues are accrued at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Terminalling and storage revenues are recognized at the time service is performed. Revenues for the transportation of crude oil are recognized either at the point of delivery or at the point of receipt pursuant to regulated and non-regulated tariffs.

Cost of Sales and Operations

Cost of sales and operations consists of the cost of crude oil, transportation and storage fees, field and pipeline operating expenses and expenses of issuing letters of credit to support crude oil purchases. Field and pipeline operating expenses consist primarily of fuel and power costs, telecommunications, labor costs for truck drivers and pipeline field personnel, maintenance, utilities, insurance and property taxes.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and at times may exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that any possible credit risk is minimal.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil. The majority of our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided in the form of standby letters of credit.

Accounts receivable included in the consolidated balance sheets are reflected net of our allowance for doubtful accounts. We routinely review our receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such delays involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. At December 31, 2002 and 2001, approximately 99% and 93%, respectively, of net accounts receivable classified as current were less than 60 days past scheduled invoice date. At December 31, 2002 and 2001, our allowance for doubtful accounts receivable classified as current totaled $3.1 million and $3.0 million, respectively, representing 31% and 11%, respectively, of all receivable balances greater than 60 days past the scheduled invoice date. At December 31, 2002 and 2001, approximately $6.5 million and $10.8 million, respectively, of net accounts receivable were classified as long-term. At December 31, 2002 and 2001, our allowance for doubtful accounts receivable classified as long-term totaled $5.0 million representing 43% and 33%, respectively, of all long-term receivable balances. We consider these reserves adequate. Following is a reconciliation of the changes in our allowance for doubtful accounts balances (in millions):

	2002	2001	2000
Balance at beginning of year	$ 8.0	$ 5.0	$ —
Charged to expense	0.1	3.0	5.0
Balance at December 31	$ 8.1	$ 8.0	$ 5.0

There were no amounts due from related parties at December 31, 2002. Amounts due from related parties totaled $0.6 million at December 31, 2001, and represented amounts due under current contracts in the ordinary course of business or billings for reimbursing expenses that were collected subsequent to year end. None of the accounts receivables are related to any equity investments in the Partnership.

Inventory

Inventory consists of crude oil and LPG in pipelines, storage tanks and rail cars which is valued at the lower of cost or market, with cost determined using an average cost method. In the fourth quarter of 2001, the Partnership recorded a $5.0 million noncash writedown of operating crude oil inventory to reflect prices at December 31, 2001. During 2001, the price of crude oil traded on the NYMEX averaged $25.98 per barrel. At December 31, 2001, the NYMEX crude oil price was approximately 24% lower, or $19.84 per barrel. There was no writedown of operating crude oil inventory at December 31, 2002, as the NYMEX crude oil price of $29.45 per barrel was higher than our average cost per barrel. At December 31, 2002 and 2001, inventory consists of (in millions):

	December 31,	
	2002	2001
Crude oil	$ 53.5	$ 132.3
LPG	28.3	56.6
	$ 81.8	$ 188.9

Property and Equipment and Pipeline Linefill

Property and equipment, net is stated at cost and consists of the following (in millions):

	December 31,	
	2002	2001
Crude oil pipelines	$ 821.8	$ 470.7
Crude oil pipeline facilities	87.5	87.4
Crude oil storage and terminal facilities	82.4	63.0
Trucking equipment, injection stations and other	30.0	25.6
Office property and equipment	8.6	6.3
	1,030.3	653.0
Less accumulated depreciation	(77.5)	(48.1)
	$ 952.8	$ 604.9

Depreciation expense for each of the three years in the period ended December 31, 2002, was $30.2 million, $21.6 million and $15.8 million, respectively. Depreciation is computed using the straight-line method over estimated useful lives as follows:

- crude oil pipelines—30 years;
- crude oil pipeline facilities—30 years;
- crude oil storage and terminal facilities—30 to 40 years;
- trucking equipment, injection stations and other—5 to 15 years; and
- office property and equipment—5 years

In accordance with our capitalization policy, acquisitions and improvements, including related interest costs of $0.8 million and $0.2 million in 2002 and 2001, respectively, are capitalized; maintenance and repairs are expensed as incurred.

Pipeline linefill is recorded at lower of cost or market and consists of crude oil and LPG used to pack a pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location as well as minimum crude oil necessary to operate our storage and terminalling facilities. At December 31, 2002, we had approximately 2.7 million barrels of crude oil and 6.4 million gallons of LPG used to maintain our minimum operating linefill requirements. Proceeds from the sale and repurchase of pipeline linefill are reflected as cash flows from operating activities in the accompanying consolidated statements of cash flows.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value in accordance with SFAS No. 144 “Accounting for the Impairment or Disposal of Long-Lived Assets.” Under SFAS 144, an asset shall be tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. We adopted SFAS 144 on January 1, 2002, and there have been no events or circumstances indicating that the carrying value of any of our assets may not be recoverable.

Other Assets

Other assets, net consist of the following (in millions):

	December 31,	
	2002	2001
Debt issue costs	$ 21.6	$ 15.7
Long term receivables, net	6.5	10.8
Goodwill	12.9	11.4
Intangible assets (contracts)	2.4	2.4
Investment in affiliate (See Note 4)	8.0	—
Other	5.2	5.0
	56.6	45.3
Less accumulated amortization	(8.3)	(4.4)
	$ 48.3	$ 40.9

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization. Goodwill is recorded as the amount of the purchase price in excess of the fair value of certain assets purchased. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets", which we adopted January 1, 2002, we test goodwill and other intangible assets periodically to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. As of December 31, 2002, no impairment has occurred. Amortization of other assets, excluding goodwill on business combinations initiated after June 30, 2001, for each of the three years in the period ended December 31, 2002, was $3.9 million, $2.7 million and $8.7 million, respectively.

Environmental Matters

We expense or capitalize, as appropriate, environmental expenditures. We expense expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action.

Income and Other Taxes

Except as noted below, no provision for U.S. federal or Canadian income taxes related to our operations is included in the accompanying consolidated financial statements, because as a partnership we are not subject to federal, state or provincial income tax and the tax effect of our activities accrues to the unitholders. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. Individual unitholders will have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual unitholder's tax bases and the unitholder's share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual unitholder's tax attributes, and the aggregate tax bases cannot be readily determined. Accordingly, we do not believe that in our circumstances, the aggregate difference would be meaningful information.

The Partnership's Canadian operations are conducted through an operating limited partnership, of which our wholly owned subsidiary PMC (Nova Scotia) Company is the general partner. For Canadian tax purposes, the general partner is taxed as a corporation, subject to income taxes and a capital-based tax at federal and provincial levels. For 2002 and 2001, the income tax was not material and the capital-based tax was approximately $0.5 million (U.S.) and $0.4 million (U.S), respectively. In addition, interest payments made by Plains Marketing Canada, L.P. on its intercompany loan from Plains Marketing, L.P. are subject to a 10% Canadian withholding tax, which for 2002 and 2001 totaled $0.5 and $0.3 million, respectively, and is recorded in other expense.

In addition to federal income taxes, owners of our common units may be subject to other taxes, such as state and local and Canadian federal and provincial taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. A unitholder may be required to file Canadian federal income tax returns, pay Canadian federal and provincial income taxes, file state income tax returns and pay taxes in various states.

Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Beginning January 1, 2001, we record all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138 (collectively "SFAS 133"). In accordance with the transition provisions of SFAS 133, we recorded a loss of $8.3 million in Other Comprehensive Income ("OCI"), representing the cumulative effect of an accounting change to recognize, at fair value, all cash flow derivatives. We also recorded a noncash gain of $0.5 million in earnings as a cumulative effect adjustment. SFAS 133 requires that changes in derivative instruments fair value be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value are deferred to OCI and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items.

Net Income Per Unit

Basic and diluted net income per unit is determined by dividing net income after deducting the amount allocated to the general partner interest, (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding common units and subordinated units. Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership. Other comprehensive income is allocated based on the same effective percentages. Basic and diluted net income per unit for 2002, 2001 and 2000 is as follows:

	Year Ended December 31,		
	2002	2001	2000
	(in millions, except per unit data)		
Net income	$ 65.3	$ 44.2	$ 77.5
Less:			
General partner incentive distributions	(3.1)	(1.1)	(0.2)
General partner 2% ownership	(1.3)	(0.9)	(1.5)
Net income attributable to limited partners	$ 60.9	$ 42.2	$ 75.8
Weighted average units outstanding	45.5	37.5	34.4
Basic and diluted net income per limited partner unit	$ 1.34	$ 1.13	$ 2.20

Foreign Currency Translation

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U.S.

dollars using the applicable exchange rate as of the end of a reporting period. Revenues and expenses are translated using the average exchange rate during the reporting period.

Recent Accounting Pronouncements

In December 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 148 "Accounting for Stock-Based Compensation—Transition and Disclosure." SFAS 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 in both annual and interim financial statements. SFAS 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. Our general partner has stock-based employee compensation plans (see Notes 12 and 13). These plans are accounted for under the fair value based method as described in SFAS 123. Therefore, we do not believe that the adoption of this statement will have a material effect on either our financial position, results of operations, cash flows or disclosure requirements.

In October 2002, the Emerging Issues Task Force ("EITF") reached consensus on certain issues in EITF Issue No. 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under Issues No. 98-10 and 00-17." The consensus reached included: i) rescinding EITF 98-10 and ii) the requirement that mark-to-market gains and losses on trading contracts (whether realized or unrealized and whether financially or physically settled) be shown net in the income statement using the indicators identified in Issue No. 98-10. The EITF provided guidance that, beginning on October 25, 2002, all new contracts that would have been accounted for under EITF 98-10 should no longer be marked-to-market through earnings unless such contracts fall within the scope of SFAS 133. All of the contracts that we have accounted for under EITF 98-10 fall within the scope of SFAS 133 and therefore will continue to be marked-to-market through earnings under the provisions of that rule. Therefore, the adoption of this rule did not have a material effect on either our financial position, results of operations or cash flows.

In June 2002, the FASB issued SFAS No. 146 "Accounting for Costs Associated with Exit or Disposal Activities." SFAS 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the obligation is incurred rather than at the date of the exit plan. This Statement is effective for exit or disposal activities that are initiated after December 31, 2002. We have not initiated exit or disposal activities that are subject to this statement and do not believe that the adoption of SFAS 146 will have a material effect on either our financial position, results of operations or cash flows.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." SFAS 145 rescinds, updates, clarifies and simplifies existing accounting pronouncements. Among other things, SFAS 145 rescinds SFAS 4, which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. Under SFAS 145, the criteria in Accounting Principles Board No. 30 will now be used to classify those gains and losses. The adoption of this and the remaining provisions of SFAS 145 did not have a material effect on our financial position or results of operations. However, any future extinguishments of debt may impact income from continuing operations (see Note 10).

In June 2001, the FASB issued SFAS No. 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Effective January 1, 2003, we adopted SFAS 143, as required. Determination of the amounts to be recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. The majority of our assets, primarily related to our pipeline operations segment, have obligations to perform removal and/or remediation activities when the asset is retired. However, the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. We will record such asset retirement obligations in the period in which we determine the settlement dates. The cumulative effect of adopting this statement will not have a material impact on our financial position, results of operations or cash flows.

Note 3—Unauthorized Trading Losses

In November 1999, we discovered that a former employee had engaged in unauthorized trading activity, resulting in losses of approximately $162.0 million ($174.0 million, including estimated associated costs and legal expenses). A full investigation into the unauthorized trading activities by outside legal counsel and independent accountants and consultants determined that the vast majority of the losses occurred from March through November 1999. Approximately $7.1 million of the unauthorized trading losses was recognized in 1998 and the remainder in 1999. In 2000, we recognized an additional $7.0 million charge for the settlement of litigation related to the unauthorized trading losses.

Note 4—Acquisitions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price was allocated in accordance with such method. In addition, we adopted SFAS No. 141, “Business Combinations” in 2001 and followed the provisions of that statement for all business combinations initiated after June 30, 2001.

Significant Acquisitions

Shell West Texas Assets

On August 1, 2002, we acquired from Shell Pipeline Company LP and Equilon Enterprises LLC interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas (the “Shell acquisition”). The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since that date. The primary assets included in the transaction were interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. These assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we are a provider of storage and terminalling services. The total purchase price of $324.4 million consisted of (i) $304.0 million in cash, which was borrowed under our revolving credit facility, (ii) approximately $9.1 million related to the settlement of pre-existing accounts receivable and inventory balances and (iii) approximately $11.3 million of estimated transaction and closing costs. The entire purchase price was allocated to property and equipment. We are in the process of evaluating certain estimates made in the purchase price allocation, including costs associated with the shutdown of the Rancho Pipeline System, thus, the allocation is subject to refinement.

CANPET Energy Group Inc.

In July 2001, we acquired the assets of CANPET Energy Group Inc. ("CANPET"), a Calgary-based Canadian crude oil and LPG marketing company, for approximately $42.0 million plus excess inventory at the closing date of approximately $25.0 million. Approximately $18.0 million of the purchase price, payable in common units, was deferred subject to various performance standards being met (see Note 8). At the time of the acquisition, CANPET's activities consisted of gathering approximately 75,000 barrels per day of crude oil and marketing an average of approximately 26,000 barrels per day of natural gas liquids or LPG's. The principal assets acquired include a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and operating inventory. The acquired assets are part of our establishment of a Canadian operation that substantially mirrors our operations in the United States. Initial financing for the acquisition was provided through borrowings under our credit facility.

The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Inventory	$	28.1
Goodwill		11.1
Intangible assets (contracts)		1.0
Pipeline linefill		4.3
Crude oil gathering, terminalling and other assets		5.1
Total	$	49.6

Murphy Oil Company Ltd. Midstream Operations

In May 2001, we closed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately $161.0 million in cash ($158.4 million after post-closing adjustments) (the "Murphy acquisition"), including financing and transaction costs. Initial financing for the acquisition was provided through borrowings under our credit facilities. The purchase included $6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 560 miles of crude oil and condensate transmission mainlines (including dual lines on which condensate is shipped for blending purposes and blended crude is shipped in the opposite direction) and associated gathering and lateral lines, approximately 1.1 million barrels of crude oil storage and terminalling capacity located primarily in Kerrobert, Saskatchewan, approximately 254,000 barrels of pipeline linefill and tank inventories, and 121 trailers used primarily for crude oil transportation. The acquired assets are part of our establishment of a Canadian operation that substantially mirrors our operations in the United States.

Murphy agreed to continue to transport production from fields previously delivering crude oil to these pipeline systems, under a long-term contract. At the time of the acquisition, the volume under the contract was approximately 11,000 barrels per day. Total volumes transported on the pipeline system in 2001 were approximately 223,000 barrels per day of light, medium and heavy crudes, as well as condensate.

The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Crude oil pipeline, gathering and terminal assets	$	148.0
Pipeline linefill		7.6
Net working capital items		2.0
Other property and equipment		0.5
Other assets, including debt issue costs		0.3
Total	$	158.4

The following unaudited pro forma data is presented to show pro forma revenues, net income and basic and diluted net income per limited partner unit for the Partnership as if the Murphy, CANPET and Shell acquisitions had occurred on January 1, 2001 (in millions, except for per unit amounts):

	Year Ended December 31,	
	2002	2001
Revenue	$ 8,410.3	$ 7,087.6
Income before cumulative effect of accounting change	$ 64.7	$ 54.5
Net Income	$ 64.7	$ 55.0
Basic and diluted income before cumulative effect of accounting change per limited partner unit	$ 1.32	$ 1.39
Basic and diluted net income per limited partner unit	$ 1.32	$ 1.40

Other Acquisitions

Coast Energy Group and Lantern Petroleum

In March 2002, we completed the acquisition of substantially all of the domestic crude oil pipeline, gathering and marketing assets of Coast Energy Group and Lantern Petroleum, divisions of Cornerstone Propane Partners, L.P., for approximately $8.3 million in cash net of liabilities assumed and transaction costs including $1.3 million of goodwill. The principal assets acquired are located in West Texas and include several gathering lines, crude oil contracts and a small truck and trailer fleet. The acquired assets serve to expand our core market in West Texas and give us access to more volume in the area.

Butte Pipe Line Company

In February 2002, we acquired an approximate 22% equity interest in Butte Pipe Line Company from Murphy Ventures, a subsidiary of Murphy Oil Corporation. The total cost of the acquisition, including various transaction and related expenses, was approximately $7.6 million. Butte Pipe Line Company owns the 373-mile Butte Pipeline System, principally a mainline system, that runs from Baker, Montana to Guernsey, Wyoming. The Butte Pipeline is connected to the Poplar Pipeline System, which in turn is connected to the Wascana Pipeline System, which is 100% wholly owned by us. We believe these pipeline systems will play an important role in moving increasing volumes of Canadian crude oil into markets in the United States.

Wapella Pipeline System

In December 2001, we acquired the Wapella Pipeline System from private investors for approximately $12.0 million, including transaction costs. The entire purchase price was allocated to property and equipment. The system is located in southeastern Saskatchewan and southwestern Manitoba and further expands our market in Canada. In 2001, the Wapella Pipeline System delivered approximately 11,000 barrels per day of crude oil to the Enbridge Pipeline at Cromer, Manitoba. The acquisition also includes approximately 21,500 barrels of crude oil storage capacity located along the system as well as a truck terminal. Initial financing for the acquisition was provided through borrowings under our credit facility.

Note 5—Asset Dispositions

During 2002, we sold various property and equipment for proceeds totaling approximately $1.4 million. No gain or loss was recognized as all items were sold at amounts approximating book value. In December 2001, we sold excess communications equipment remaining from the sale of the All American Pipeline discussed below and recognized a gain of $1.0 million.

In March 2000, we sold to a unit of El Paso Corporation for $129.0 million the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas. Except for minor third-party volumes, one of our subsidiaries, Plains Marketing, L.P., was the sole shipper on this segment of the pipeline since the acquisition of the line from Goodyear in July 1998. We realized net proceeds of approximately $124.0 million after the associated transaction costs and estimated costs to remove equipment. We used the proceeds from the sale to reduce outstanding debt. We recognized a gain of approximately $20.1 million in connection with the sale.

We had suspended shipments of crude oil on this segment of the pipeline in November 1999. At that time, we owned approximately 5.2 million barrels of crude oil in the segment of the pipeline. We sold this crude oil from November 1999 to February 2000 for net proceeds of approximately $100.0 million, which were used for working capital purposes. We recognized gains of approximately $28.1 million in 2000, in connection with the sale of the linefill.

Note 6—Recent Disruptions in Industry Credit Markets

As a result of business failures, revelations of material misrepresentations and related financial restatements by several large, well-known companies in various industries during 2001 and 2002, there have been significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and troubling disclosures by several large, diversified energy companies, the energy industry has been especially impacted by these developments, with the rating agencies downgrading a number of large, energy-related companies. Accordingly, in this environment we are exposed to an increased level of direct and indirect counterparty credit and performance risk.

The majority of our credit extensions and therefore our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. In transacting business with our counterparties, we must determine the amount, if any, of open credit lines to extend to our counterparties and the form and amount of financial performance assurances we may require. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. As a result of these developments, during 2002 we modified our ongoing credit arrangements with certain counterparties, reducing or eliminating the amount of open credit we extend and requiring prepayments or standby letters of credit for business activities that exceed these revised credit limits.

The vast majority of our accounts receivable settle monthly and any collection delays generally involve discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered or exchanged and associated billing delays. At December 31, 2002, approximately 99% of our net accounts receivables included in current assets are less than 60 days past scheduled invoice date (see Note 2). The majority of the remaining 1% and the balance of accounts receivable classified as long-term relate to monthly periods leading up to and immediately following the disclosure of unauthorized trading losses that we experienced in late 1999. Such balances are subject to ongoing reconciliations primarily to resolve discrepancies associated with pricing, volumes, quality or crude oil exchange imbalances. Following the unauthorized trading loss disclosure, a significant number of our suppliers and trading partners temporarily reduced or eliminated our open credit and demanded payments or withheld payments due us before disputed amounts or discrepancies were reconciled in accordance with customary industry practices. Because these matters also arose in the midst of various software systems conversions and acquisition integration activities, our effort to resolve outstanding claims and discrepancies has included reprocessing and integrating historical information on numerous software platforms.

During 2002, significant, concerted effort was directed to resolving these matters in an ongoing effort to bring substantially all receivable balances to within sixty days of scheduled invoice date. As a result of this effort, the aggregate balance of all accounts receivable balances greater than sixty days past scheduled invoice date at December 31, 2001 was reduced by approximately 64% and the balance of our accounts receivable included in current assets that were less than 60 days past scheduled invoice date improved to 99% at December 31, 2002 from 93% at December 31, 2001. Based on the work performed to date, we believe net receivable balances greater than sixty days past scheduled invoice date are collectible or subject to offsets and consider our reserves adequate. However, since certain of these obligations are not secured by letters of credit, in the event our counterparties experience an unanticipated deterioration in their credit-worthiness, any addition to existing reserves or write-offs in excess of such reserves would result in a noncash charge to earnings. We do not believe any such charge would have a material effect on our cash flow or liquidity.

Note 7—Debt

Short-term debt and current maturities of long-term debt consist of the following (in millions):

	December 31,	
	2002	2001
Senior secured letter of credit and borrowing facility bearing interest at a rate of 3.4% at December 31, 2002, and 3.8% at December 31, 2001	$ 97.7	$ 100.0
Other	1.5	1.5
	99.2	101.5
Current portion of long-term debt[(1)]	—	3.0
Total short-term debt and current maturities of long-term debt	$ 99.2	$ 104.5

(1) At December 31, 2002, we have classified $9 million of term loan payments due in 2003 as long term due to our intent and ability to refinance those maturities using the revolving facility.

Long-term debt consists of the following (in millions):

	December 31,	
	2002	2001
7.75% senior notes due October 2012, net of unamortized discount of $0.4	$ 199.6	$ —
Senior secured domestic revolving credit facility, bearing interest at a rate of 4.8% at December 31, 2002, and 4.5% at December 31, 2001	10.4	27.5
Senior secured term B loan, bearing interest at a rate of 3.9% at December 31, 2002, and 4.5% at December 31, 2001[(1)]	198.0	200.0
Senior secured term loan, bearing interest at a rate of 3.9% at December 31, 2002, and 4.4% at December 31, 2001[(1)]	99.0	100.0
Senior secured Canadian revolving credit facility, bearing interest at a rate of 5.0% at December 31, 2002 and 4.4% at December 31, 2001	2.7	27.2
	509.7	354.7
Less current maturities[(1)]	—	(3.0)
Total long-term debt	$ 509.7	$ 351.7

(1) At December 31, 2002, we have classified $9 million of term loan payments due in 2003 as long term due to our intent and ability to refinance those maturities using the revolving facility.

During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012. The notes were issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) at a discount of $0.4 million, resulting in an effective interest rate of 7.78%. Interest payments are due on April 15 and October 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor.

During 2002, we amended our credit facilities to enable us to consummate the Shell acquisition, to remove a condition requiring us to obtain lender approval before making any acquisition greater than $50.0 million and to accommodate the increased activity level associated with the expanded asset base, while preserving our ability to pursue additional acquisitions.

As amended during 2002 and giving effect to the third quarter capital raising activities, our credit facilities consist of a $350.0 million senior secured letter of credit and hedged inventory facility (with current lender commitments totaling $200.0 million), and a $747.0 million senior secured revolving credit and term loan facility, each of which is secured by substantially all of our assets. The terms of our credit facilities enable us to expand the commitments under the letter of credit and hedged inventory facility from $200.0 million to $350.0 million without additional approval from existing lenders. The revolving credit and term loan facility consists of a $420.0 million domestic revolving facility (with a $10.0 million letter of credit sublimit), a $30.0 million Canadian revolving facility (with a $5.0 million letter of credit sublimit), a $99.0 million term loan, and a $198.0 million term B loan.

As is customary in our industry, and in connection with our crude oil marketing, we provide certain purchasers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At December 31, 2002 and 2001, we had outstanding letters of credit of approximately $52.5 million and $30.1 million, respectively. These letters of credit are secured by our crude oil inventory and accounts receivable.

The instruments that comprise our credit facilities bear interest based on floating rates. The weighted average interest rate during the years ended December 31, 2002 and December 31, 2001, respectively, for each of the instruments are as follows: (i) 3.4% and 5.3% for the $350.0 million senior secured letter of credit and hedged inventory facility, (ii) 4.4 % and 7.1 % for the $420.0 million domestic revolving facility, (iii) 4.5% and 5.5% for the $30.0 million Canadian revolving facility, (iv) 4.1% and 6.7% for the $99.0 million term loan and (v) 4.5% and 5.0% for the $198.0 million term loan.

The facilities have final maturities as follows:

- as to the $350.0 million senior secured letter of credit and hedged inventory facility and the aggregate $450.0 million domestic and Canadian revolver portions, in April 2005;
- as to the $99.0 million term loan, in May 2006; and
- as to the $198.0 million term B loan, in September 2007.

Our credit facilities and the indenture governing the 7.75% senior notes contain cross default provisions. Our credit facilities prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness;
- grant liens;
- sell assets;
- make investments;
- engage in transactions with affiliates;
- enter into prohibited contracts; and
- enter into a merger or consolidation.

Our credit facilities treat a change of control as an event of default and also require us to maintain:

- a current ratio (as defined) of at least 1.0 to 1.0;
- a debt coverage ratio which will not be greater than: 5.25 to 1.0 on all outstanding debt and 4.0 to 1.0 on secured debt;
- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt to capital ratio of not greater than 0.7 to 1.0 through March 30, 2003, and 0.65 to 1.0 at any time thereafter.

For covenant compliance purposes, letters of credit and borrowings under the letter of credit and hedged inventory facility are excluded when calculating the debt coverage and debt to capital ratios. Additionally, under the covenants, unborrowed availability under the $450 million domestic and Canadian revolving credit facilities is added to working capital to calculate the current ratio for compliance purposes. At December 31, 2002, unborrowed availability was approximately $436.9 for purposes of calculating the current ratio.

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt and to foreclose on the assets securing the credit facilities. As long as we are in compliance with our credit agreements, they do not restrict our ability to make distributions of “available cash” as defined in our partnership agreement. We are in compliance with the covenants contained in our credit facilities and 7.75% senior notes credit agreements.

The amended facility permits us to issue up to an aggregate of $400.0 million of senior unsecured debt that has a maturity date extending beyond the maturity date of the existing credit facility, and provides a mechanism to reduce the amount of the domestic revolving credit facility. The foregoing description of the credit facility incorporates the reduction associated with the $200 million senior note offering completed in September 2002. Depending on the amount of additional senior indebtedness incurred, the domestic revolving credit facility will be reduced by an amount equating to 40% to 63% of any incremental indebtedness up to the aggregate $400 million limitation.

Maturities

The average life of our long-term debt at December 31, 2002, was approximately 6.3 years and the aggregate maturities for the next five years are as follows (in millions):

Calendar Year	Payment
2003	$ 9.0
2004	10.0
2005	23.1
2006	78.0
2007	190.0
Thereafter	200.0
Total[1]	510.1

(1) Includes unamortized discount on 7.75% senior notes of $0.4 million.

Note 8—Partners' Capital and Distributions

Partners' capital consists of (1) 39,548,129 common units, including 1,307,190 Class B common units, representing a 78.2% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving affect to the general partner interest), (2) 10,029,619 subordinated units representing a 19.8% effective aggregate ownership interest in the Partnership and its subsidiaries (after giving affect to the general partner interest) and (3) a 2% general partner interest.

In August 2002, we completed a public offering of 6,325,000 common units for $23.50 per unit. The offering resulted in cash proceeds of approximately $148.6 million from the sale of the units and approximately $3.0 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $6.6 million. Net proceeds of approximately $145.0 million were used to reduce outstanding borrowings under the domestic revolving credit facility.

In May 2001, we completed a public offering of 3,966,700 common units. Total net cash proceeds from the offering, including our former general partner's proportionate contribution, were approximately $100.7 million. In addition, in October 2001, we completed a public offering of 4,900,000 common units. Net cash proceeds from the offering, including our general partner's proportionate contribution, were approximately $126.0 million. The net proceeds were used to repay borrowings under our revolving credit facility, a portion of which was used to finance our Canadian acquisitions.

We will distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established by our general partner for future requirements. Distributions of available cash to holders of subordinated units are subject to the prior rights of holders of common units to receive the minimum quarterly distribution ("MQD") for each quarter during the subordination period and to receive any arrearages in the distribution of the MQD on the common units for the prior quarters during the subordination period. There were no arrearages on common units at December 31, 2002. The MQD is $0.45 per unit ($1.80 per unit on an annual basis). Common units will not accrue arrearages with respect to distributions for any quarter after the subordination period and subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The subordination period (as defined in the partnership agreement) will end if certain financial tests are met for three consecutive four-quarter periods (the "testing period"), but not sooner than December 31, 2003. During the first quarter after the end of the subordination period, all of the subordinated units will convert into common units, and will participate pro rata with all other common units in future distributions. Early conversion of a portion of the subordinated units may occur if the testing period is satisfied before December 31, 2003. We are now in the testing period and, if we continue to meet the requirements, 25% of the subordinated units will convert in the fourth quarter of 2003 and the remainder will convert in the first quarter of 2004.

In connection with the CANPET acquisition in July 2001, approximately $18 million of the purchase price, payable in common units, was deferred subject to various performance standards being met. The deferred amount will be paid in April 2004 if the standards are met. The number of common units issued in satisfaction of the deferred payment will depend upon the market value of common units at the time of payment. In addition, an amount will be paid equivalent to the distributions that would have been paid on the common units had they been outstanding since the acquisition was consummated. We may, at our option, satisfy the deferred payment in cash rather than the issuance of units.

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally the general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit. Cash distributions on our outstanding common units, Class B common units and subordinated units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2002		2001		2000	
	Distribution	Excess over MQD	Distribution	Excess over MQD	Distribution	Excess over MQD
First Quarter	$ 0.5250	$ 0.0750	$ 0.4750	$ 0.0250	$ 0.4500[(1)]	$ —
Second Quarter	$ 0.5375	$ 0.0875	$ 0.5000	$ 0.0500	$ 0.4625	$ 0.0125
Third Quarter	$ 0.5375	$ 0.0875	$ 0.5125	$ 0.0625	$ 0.4625	$ 0.0125
Fourth Quarter	$ 0.5375	$ 0.0875	$ 0.5125	$ 0.0625	$ 0.4625	$ 0.0125

(1) Reflects distributions to common and Class B common unitholders only. No distribution was declared or paid on the subordinated units owned by our former general partner in this period.

The Class B common units are initially pari passu with common units with respect to distributions, and are convertible into common units upon approval of a majority of the common unitholders. The Class B unitholders may request that we call a meeting of common unitholders to consider approval of the conversion of Class B units into common units. If the approval of a conversion by the common unitholders is not obtained within 120 days of a request, each Class B common unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, Class B common units have the same voting rights as the common units.

During 2002, we paid distributions of approximately $99.8 million ($2.11 on a per unit basis), with approximately $73.6 million paid to our common unitholders, $21.1 million paid to our subordinated unitholders and $5.1 million paid to our general partner for its general partner ($2.0 million) and incentive distribution interests ($3.1 million). The distribution was in excess of the minimum quarterly distribution specified in the partnership agreement.

On January 24, 2003, we declared a cash distribution of $0.5375 per unit on our outstanding common units, Class B common units and subordinated units. The distribution was paid on February 14, 2003, to unitholders of record on February 4, 2003, for the period October 1, 2002, through December 31, 2002. The total distribution paid was approximately $28.2 million, with approximately $21.2 million paid to our common unitholders, $5.4 million paid to our subordinated unitholders and $1.6 million paid to our general partner for its general partner ($0.6 million) and incentive distribution interests ($1.0 million). The distribution was in excess of the minimum quarterly distribution specified in the partnership agreement.

Note 9—Derivatives and Financial Instruments

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk.

Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Commodity Price Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the New York Mercantile Exchange and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies (see Note 6 for a discussion of the mitigation of credit risk). In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair values. The majority of our commodity price risk derivative instruments qualify for hedge accounting as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedge are deferred to OCI and recognized in revenues or cost of sales and operations in the periods during which the underlying physical transactions occur. At December 31, 2002 there was income of $1.2 million deferred in OCI related to our commodity price risk activities. Insignificant amounts related to these activities were deferred to OCI at December 31, 2001. At December 31, 2002, all of our future positions mature by December, 2004. For the years ended December 31, 2002 and 2001, income of $0.3 million and $0.4 million (excluding the impact of the adoption of SFAS 133), respectively, was included in earnings due to changes in the fair value of derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective. We have determined that our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133.

Controlled Trading Program

As a result of production and delivery variances associated with our lease purchase activities, from time to time we experience net unbalanced positions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to 500,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues. Although there were no open positions under this program at December 31, 2002 and 2001, the realized earnings impact related to these derivatives for the years ended December 31, 2002 and 2001, was income of $0.1 million and a loss of $0.9 million, respectively.

Interest Rate Risk Hedging

We also utilize various products, such as interest rate swaps, collars and treasury locks to hedge interest obligations on specific debt issuances, including anticipated debt issuances. All of these instruments are placed with large creditworthy financial institutions.

The instruments outstanding at December 31, 2002, consist of interest rate swaps and a treasury lock with an aggregate notional principal amount of $150 million. The interest rate swaps are based on LIBOR rates and provide for a LIBOR rate of 5.1% for a $50.0 million notional principal amount expiring October 2006, and a LIBOR rate of 4.3% for a $50.0 million notional principal amount expiring March 2004. Interest on the underlying debt being hedged is based on LIBOR plus a margin. During 2002, we entered into a treasury lock in anticipation of the issuance of our 7.75% senior notes due October 2012 and potential subsequent add-on thereto. A treasury lock is a financial derivative instrument that enables the company to lock in the U.S. Treasury Note rate. The treasury lock has notional principal amount of $50.0 million and an effective interest rate of 4.60% and matures in January 2003. In January, 2003, the treasury lock maturity was extended to March, 2003 with an effective interest rate of 4.68%.

The instruments outstanding at December 31, 2001, consisted of interest rate swaps and collars with an aggregate notional principal amount of $275 million and were based on LIBOR rates. The collar provides for a floor of 6.1% and a ceiling of 8.0% with an expiration date of August 2002 for $125.0 million notional principal amount. The fixed rate interest rate swaps provide for a rate of 4.3% for $50.0 million notional principal amount expiring March 2004, and a rate of 3.6% for $100.0 million notional principal amount expiring September 2003.

The instruments outstanding at December 31, 2002 and 2001 qualify for hedge accounting as cash flow hedges in accordance with SFAS 133. The effective portion of changes in fair values of these hedges is recorded in OCI until the related hedged item impacts earnings. At December 31, 2002, there was a $9.6 million loss, deferred in OCI related to our interest rate risk activities. Insignificant amounts related to these activities were deferred to OCI at December 31, 2001. During 2002 and 2001, there were no amounts recognized in earnings related to hedge ineffectiveness.

Based on December 31, 2002, debt balances, floating rate indexes at the end of January 2003, our credit spread under our credit facilities and the combination of our fixed rate debt and current interest rate hedges, our average interest rate was approximately 6.1%, excluding non-use and facilities fees, which will vary based on usage and outstanding balance. We have locked-in interest rates (excluding the credit spread under the credit facilities) for approximately 60% of our total debt for 2003, 50% for the next four years and 40% for the next ten years.

Currency Exchange Rate Risk Hedging

Since substantially all of our Canadian business is conducted in Canadian dollars (CAD), we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts, forward extra option contracts and cross currency swaps. Additionally, at

December 31, 2002 and 2001, $2.7 million and $25.4 million, respectively of our long-term debt was denominated in Canadian dollars ($4.3 million and $40.5 million CAD based on a Canadian-U.S. dollar exchange rate of 1.58 and 1.59, respectively). All of these financial instruments are placed with large creditworthy financial institutions.

At December 31, 2002 and 2001, we had forward exchange contracts and forward extra option contracts that allow us to exchange $3.0 million Canadian for at least $1.9 million U.S. quarterly during 2002 and 2003 (based on a Canadian-U.S. dollar exchange rate of 1.54 and 1.55, respectively). At December 31, 2002 and 2001, we also had cross currency swap contracts for an aggregate notional principal amount of $24.8 million and $25.0 million, respectively, effectively converting this amount of our senior secured term loan (25% of the total) from U.S. dollars to $38.3 million and $38.7 million of Canadian dollar debt (based on a Canadian-U.S. dollar exchange rate of 1.55). The terms of this contract mirror the term loan, matching the amortization schedule and final maturity in May 2006.

The forward exchange contracts and forward extra option contracts qualify for hedge accounting as cash flow hedges and the cross currency swaps qualify for hedge accounting as fair value hedges, both in accordance with SFAS 133. Such derivative activity resulted in income of $0.2 million deferred in OCI related to our currency exchange rate cash flow hedges at December 31, 2002. No amounts related to these activities were deferred to OCI at December 31, 2001. The earnings impact related to our currency exchange rate fair value hedges was nominal for the year ended December 31, 2002 and a loss of $0.2 million for the year ended December 31, 2001.

Summary of Financial Impact

The following is a summary of the financial impact of the derivative instruments and hedging activities discussed above. At December 31, 2002, the balance sheet includes assets of $15.5 million ($12.9 million current), liabilities of $22.8 million ($16.0 million current) and related unrealized losses deferred to OCI of $8.2 million. In addition, revenues for the year ended December 31, 2002 include a noncash gain of $0.3 million ($1.0 million noncash gain net of the reversal of the prior period fair value adjustment related to contracts that settled during the current year). Our hedge-related assets and liabilities are included in other current and non-current assets and liabilities in the consolidated balance sheet.

As of December 31, 2002, the total amount of deferred net losses recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. During the periods ended December 31, 2002 and 2001, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring. Based on the amounts deferred to OCI at December 31, 2002, a loss of $1.9 million will be reclassified to earnings in the next twelve months and the remainder by December 2005. Since these amounts are based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

Fair Value of Financial Instruments

The carrying amounts and fair values of our financial instruments are as follows (in millions):

	December 31,			
	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
NYMEX futures	$ 0.6	$ 0.6	$ (1.1)	$ (1.1)
Options and swaps	$ (0.6)	$ (0.6)	$ —	$ —
Forward exchange contracts	$ 0.1	$ 0.1	$ 0.2	$ 0.2
Forward extra option contracts	$ 0.2	$ 0.2	$ 0.3	$ 0.3
Cross currency swaps	$ 0.3	$ 0.3	$ 0.5	$ 0.5
Treasury lock	$ (3.3)	$ (3.3)	$ —	$ —
Interest rate collars	$ —	$ —	$ (3.8)	$ (3.8)
Interest rate swaps	$ (6.3)	$ (6.3)	$ (1.5)	$ (1.5)
Short and long-term debt	$ 609.0	$ 618.4	$ 456.2	$ 456.2

As of December 31, 2002 and 2001, the carrying amounts of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. The carrying amounts of the variable rate instruments in our credit facilities approximate fair value primarily because the interest rates fluctuate with prevailing market rates, while the interest rate on the 7.75% senior notes is fixed and the fair value is based on quoted market prices.

The carrying amount of our derivative financial instruments approximate fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. Our derivative financial instruments include cross currency swaps, forward exchange and extra option contracts, interest rate swap collar and treasury lock agreements for which fair values are based on current termination values. We also have over-the-counter option and swap contracts for which fair values are estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. In addition, we have NYMEX futures and options for which the fair values are based on quoted market prices.

Note 10—Early Extinguishment of Debt

During 2000, we recognized extraordinary losses, consisting primarily of unamortized debt issue costs, totaling $15.1 million related to the permanent reduction of the All American Pipeline, L.P. term loan facility and the refinancing of our credit facilities. In addition, interest and other income for the year ended December 31, 2000, included $9.7 million of previously deferred gains from terminated interest rate swaps as a result of debt extinguishments related to the unauthorized trading losses (see Note 3).

Note 11—Major Customers and Concentration of Credit Risk

Marathon Ashland Petroleum accounted for 10%, 11% and 12% of our revenues for each of the three years in the period ended December 31, 2002. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of the revenues from Marathon Ashland Petroleum pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of this customer would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered credit worthy, unless the credit risk can otherwise be reduced (see Note 6).

Note 12—Related Party Transactions

Reimbursement of Expenses of Our General Partner and Its Affiliates

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). Our general partner does not receive a management fee or other compensation in connection with its management of us. We reimburse our general partner for all direct and indirect costs of services provided, including the costs of employee, officer and director compensation and benefits allocable to us, and all other expenses necessary or appropriate to the conduct of our business, and allocable to us. Our agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Historically, an allocation was made for overhead associated with officers and employees who divided time between us and Plains Resources. As a result of the General Partner Transition, all of the employees and officers of the general partner devote 100% of their efforts to our business and there are no allocated expenses. Total costs reimbursed by us to our general partner in 2002 and 2001 were approximately $70.8 million and $31.3 million, respectively. Total costs reimbursed by us to our former general partner and Plains Resources were approximately $31.2 million and $63.8 million for the years ended December 31, 2001 and 2000, respectively, and include for periods prior to 2001: (1) allocated personnel costs (such as salaries and employee benefits) of the personnel providing such services, (2) rent on office space allocated to our general partner in Plains Resources' offices in Houston, Texas, (3) property and casualty insurance premiums and (4) out-of-pocket expenses related to the provision of such services.

Crude Oil Marketing Agreement

We are the exclusive marketer/purchaser for all of Plains Resources' and its subsidiaries' equity crude oil production. The marketing agreement with Plains Resources provides that we will purchase for resale at market prices all of Plains Resources' crude oil production for which we charge a fee of $0.20 per barrel. This fee is subject to adjustment every three years based on then-existing market conditions. For the years ended December 31, 2002, 2001 and 2000, we paid Plains Resources approximately $247.7 million, $223.2 million and $244.9 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production, and recognized margins of approximately $1.8 million, $1.8 million and $1.7 million from the marketing fee for the same periods, respectively. In our opinion, these purchases were made at prevailing market prices. In November 2001, the marketing agreement automatically extended for an additional three-year period. On December 18, 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production ("PXP"), to its shareholders. PXP owns crude oil properties and is a successor participant to this marketing agreement.

Separation Agreement

A separation agreement was entered into in connection with the General Partner Transition pursuant to which (i) Plains Resources has indemnified us for (a) claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on alleged acts or omissions occurring on or prior to June 8, 2001 or (b) claims related to the upstream business, whenever arising, and (ii) we have indemnified Plains Resources for claims related to the midstream business, whenever arising. Plains Resources also has agreed to indemnify and maintain liability insurance for the individuals who were, on or before June 8, 2001, directors or officers of Plains Resources or our former general partner.

Financing

In May 2000, we repaid to our former general partner $114.0 million of subordinated debt. Interest expense related to the notes was $3.3 million for the year ended December 31, 2000.

Due to Related Parties

The balance of amounts due to related parties at December 31, 2002 and 2001 was $23.3 million and $13.7 million, respectively, and was related to crude oil purchased by us but not yet paid as of December 31 of each year.

Transaction Grant Agreements

In connection with our initial public offering, our former general partner, at no cost to us, agreed to transfer, subject to vesting, approximately 400,000 of its affiliates' common units (including distribution equivalent rights attributable to such units) to certain key officers and employees of our former general partner and its affiliates. Under these grants, the common units vested based on attaining a targeted operating surplus for a given year. Of the 400,000 units subject to the transaction grant agreements, 69,444 units vested in 2000 for 1999's operating results and 133,336 units vested in 2001 for 2000's operating results. The remainder (197,220 units) vested in connection with the consummation of the General Partner Transition. Distribution equivalent rights were paid in cash at the time of the vesting of the associated common units. The values of the units and associated distribution equivalent rights that vested under the Transaction Grant Agreements for all grantees in 2001 and 2000 were $5.7 million and $3.1 million, respectively. Although we recorded noncash compensation expenses with respect to these vestings, the compensation expense incurred in connection with these grants was funded by our former general partner, without reimbursement by us.

Performance Option Plan

In connection with the General Partner Transition, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 375,000 units have been granted. Such options vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The first such level was reached, and 25% of the options vested, in 2002. The options will vest immediately upon a change in control (as defined in the grant agreements). The original purchase price under the options is $22 per subordinated unit, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of February 21, 2003, the purchase price was $19.07 per unit. The terms of future grants may differ from the existing grants. Because the subordinated units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options.

Stock Option Replacement

In connection with the General Partner Transition, certain members of the management team that had been employed by Plains Resources were transferred to the general partner. At that time, such individuals held in-the-money but unvested stock options in Plains Resources, which were subject to forfeiture because of the transfer of employment. Plains Resources, through its affiliates, agreed to substitute a contingent grant of subordinated units with a value equal to the spread on the unvested options, with distribution equivalent rights from the date of grant. The subordinated units vest on the same schedule as the stock options would have vested. The general partner administers the vesting and delivery of the units under the grants. Because the units necessary to satisfy the delivery requirements under the grants are provided by Plains Resources, we have no obligation to reimburse the general partner for the cost of such units.

Benefit Plan

A subsidiary of Plains Resources was, until June 8, 2001, our general partner. On that date, such entity transferred the general partner interest to Plains AAP, L.P. Effective July 1, 2001, Plains All American GP LLC (Plains AAP, L.P.'s general partner), maintains a 401(k) defined contribution plan whereby it matches 100% of an employee's contribution (subject to certain limitations in the plan). For the period July 1 through December 31, 2001, defined contribution plan expense was approximately $1.1 million. For the year ended December 31, 2002, defined contribution plan expense was approximately $2.1 million.

Prior to July 1, 2001, Plains Resources maintained a 401(k) defined contribution plan whereby it matched 100% of an employee's contribution (subject to certain limitations in the plan), with matching contributions being made 50% in cash and 50% in common stock of Plains Resources (the number of shares for the stock match being based on the market value of the common stock at the time the shares were granted). For the period January 1 through June 30, 2001, defined contribution plan expense was $1.0 million. For the year ended December 31, 2000, defined contribution plan expense was approximately $1.0 million.

Note 13—Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan for employees and directors of our general partner and its affiliates who perform services for us. The Long-Term Incentive Plan consists of two components, a restricted unit plan and a unit option plan. The Long-Term Incentive Plan currently permits the grant of restricted units and unit options covering an aggregate of 1,425,000 common units. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors in its discretion may terminate the Long-Term Incentive Plan at any time with respect to any common units for which a grant has not yet been made. Our general partner's board of directors also has the right to alter or amend the Long-Term Incentive Plan or any part of the plan from time to time, including increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Restricted Unit Plan. A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. As of December 31, 2002, aggregate outstanding grants of approximately 1,047,000 restricted units have been made to employees, officers and directors of our general partner. The Compensation Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine. Restricted units granted to employees during the subordination period, although additional vesting criteria may sometimes apply, will vest only after, and in the same proportions as, the conversion of the subordinated units to common units. Grants made to non-employee directors of our general partner are eligible to vest prior to termination of the subordination period.

If a grantee terminates employment or membership on the board for any reason, the grantee's restricted units will be automatically forfeited unless, and to the extent, the Compensation Committee provides otherwise. Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, we may issue up to 975,000 common units to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan (see below). If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. Following the subordination period, the Compensation Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units.

The restricted units (other than director grants) will vest only after, and in the same proportion as, any conversion of subordinated units into common units. As discussed below, subordinated units will convert at the end of the subordination period (as defined in the partnership agreement). After conversion of the subordinated units, most of the restricted units are subject to an additional 90-day waiting period before vesting occurs. Certain of the restricted unit grants contain additional vesting requirements tied to the Partnership achieving targeted distribution thresholds, generally $2.10, $2.30 and $2.50 per unit (annualized).

The subordination period (as defined in the partnership agreement) will end if certain financial tests are met for three consecutive four-quarter periods (the "testing period"), but no sooner than December 31, 2003. During the first quarter after the end of the subordination period, all of the subordinated units will convert into common units. Early conversion of a portion of the subordinated units may occur if the testing period is satisfied before December 31, 2003.

Under generally accepted accounting principles, we are required to recognize an expense when the financial tests for conversion of subordinated units and required distribution levels are met. The financial tests involve GAAP accounting concepts as well as complex and esoteric cash receipts and disbursement concepts that are indexed to the minimum quarterly distribution rate of $1.80 per limited partner unit. Because of this complexity, it is difficult to forecast when the vesting of these restricted units will occur. However, at the current annualized distribution level of $2.15 per unit, assuming the subordination conversion test is met, the costs associated with the vesting of up to approximately 845,000 units would be incurred or accrued in the second half of 2003 or the first quarter of 2004. At an annualized distribution level of $2.30 to $2.49, the number of units would be approximately 935,000. At a distribution level at or above $2.50, the number of units would be approximately 1,025,000. Our ability to continue to meet the requirements for conversion and vesting is subject to a number of economic and operational contingencies.

We are currently planning to issue units to satisfy the first 975,000 vested and delivered (after any units withheld for taxes), and to purchase units in the open market to satisfy any vesting obligations in excess of that amount. Issuance of units would result in a non-cash compensation expense, while a purchase of units would result in a cash charge to compensation expense. In addition, the "company match" portion of payroll taxes, plus the value of any units withheld for taxes, would result in a cash charge. The amount of the charge to expense will depend on the unit price on the date vesting occurs, multiplied by the number of units.

The issuance of the common units pursuant to the restricted unit plan is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration will be paid to us by the plan participants upon receipt of the common units.

In 2000, the three non-employee directors of our former general partner (Messrs. Goyanes, Sinnott and Smith) were each granted 5,000 restricted units. These units vested in connection with the consummation of the General Partner Transition. Additional grants of 5,000 restricted units were made in 2002 to each non-employee director of our general partner. These units vest in 25% increments on each anniversary of June 8, 2001. The first vesting took place on June 8, 2002.

Unit Option Plan. The Unit Option Plan under our Long-Term Incentive Plan currently permits the grant of options covering common units. No grants have been made under the Unit Option Plan to date. However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant. Unit options granted during the subordination period will become exercisable automatically upon, and in the same proportions as, the conversion of the subordinated units to common units, unless a later vesting date is provided.

Upon exercise of a unit option, our general partner may deliver common units acquired by it in the open market, or in private transactions, or use common units already owned by our general partner, or any combination of the foregoing. In addition, we may issue up to 975,000 common units to satisfy delivery obligations under the grants less any common units issued upon vesting of restricted units under the plan. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring such common units and the proceeds received by our general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and our general partner will remit to us the proceeds received by it from the optionee upon exercise of the unit option.

Certain employees and officers of the general partner have received grants of equity not associated with the Long-Term Incentive Plan described above, and for which we have no cost or reimbursement obligations (see Note 12).

Note 14—Commitments and Contingencies

We lease certain real property, equipment and operating facilities under various operating leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancellable commitments related to these items at December 31, 2002, are summarized below (in millions):

2003	$	9.4
2004	$	9.6
2005	$	9.4
2006	$	7.0
2007	$	2.7
Thereafter	$	0.5

Total lease expense incurred for 2002, 2001 and 2000 was $8.3 million, $7.4 million and $6.7 million, respectively. As is common within the industry and in the ordinary course of business, we have also entered into various operational commitments and agreements related to pipeline operations and to marketing, transportation, terminalling and storage of crude oil and liquefied petroleum gas.

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the short supply controls of the Export Administration Regulations EAR and must be licensed by the Bureau of Industry and Security (the “BIS”) of the U.S. Department of Commerce. We have determined that we may have exceeded the quantity of crude oil exports authorized by previous licenses. Export of crude oil in excess of the authorized amounts is a violation of the EAR. On October 18, 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and have received a new license allowing for exports of volumes more than adequately reflecting our anticipated needs. At this time, we have received no indication whether the BIS intends to charge us with a violation of the EAR or, if so, what penalties would be assessed. As a result, we cannot estimate the ultimate impact of these potential violations.

Other Litigation. We, in the ordinary course of business, are a claimant and/or a defendant in various other legal proceedings. We do not believe that the outcome of these other legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Other

A pipeline, terminal or other facilities may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers all of our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. The events of September 11, 2001, and their overall effect on the insurance industry has adversely impacted the availability and cost of coverage. Due to these events, insurers have excluded acts of terrorism and sabotage from our insurance policies. On certain of our key assets, we purchased a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets (including our nation’s pipeline infrastructure) may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. The DOT has developed a security guidance document and has issued a security circular that defines critical pipeline facilities and appropriate countermeasures for protecting them, and explains how DOT plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the DOT, we have specifically identified certain of our facilities as DOT “critical facilities” and therefore potential terrorist targets. In compliance with DOT guidance, we are performing vulnerability analyses on such facilities. Upon completion of such analyses, we will institute as appropriate any indicated security measures or procedures that are not already in place. We cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition.

We believe that we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business.

Note 15—Environmental Remediation

In connection with various acquisitions, we have received indemnities from the sellers for environmental exposure, subject to our prior payment of certain threshold amounts. Based on our investigations of the assets acquired in such acquisitions, we have identified several sites that exceed the threshold limitations under the various indemnities. Although we have not yet determined the total cost of remediation of these sites, we believe our indemnification arrangements should prevent such costs from having a material adverse effect on our financial condition, results of operations or cash flows.

During 2002, we reassessed previous investigations and completed environmental studies related to environmental conditions associated with our 1999 acquisitions. As of December 31, 2002, we have a $1.6 million accrual associated with our remediation obligations of these sites. This amount is approximately equal to the threshold amounts the partnership must incur before the sellers' indemnities take effect. In many cases, the actual cash expenditures may not occur for ten years and, accordingly, the majority of the liability is included in other long-term liabilities on the consolidated balance sheet.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover releases that were previously unidentified. Although we maintain an extensive inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any future environmental releases from our assets may substantially affect our business.

Note 16—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total[1]
	(in millions, except per unit data)				
2002					
Revenues	$ 1,545.3	$ 1,985.3	$ 2,344.1	$ 2,509.5	$8,384.2
Gross margin	38.4	41.7	44.3	49.9	174.3
Operating income	20.7	23.4	23.8	26.7	94.6
Net income	14.3	17.0	16.3	17.7	65.3
Income per limited partner unit	0.31	0.37	0.33	0.33	1.34
Cash distributions per common unit[2]	$ 0.525	$ 0.538	$ 0.538	$ 0.538	$ 2.14
2001					
Revenues	$ 1,520.1	$ 1,586.6	$ 2,191.3	$ 1,570.2	$6,868.2
Gross margin	32.7	36.4	39.6	33.5	142.3
Operating income	19.1	14.8	22.9	14.5	71.4
Income before cumulative effect of accounting change	12.5	7.1	15.2	8.9	43.7
Cumulative effect of accounting change	0.5	—	—	—	0.5
Net income	13.0	7.1	15.2	8.9	44.2
Income per limited partner unit before cumulative effect of accounting change	0.36	0.19	0.38	0.20	1.12
Cumulative effect of accounting change	0.01	—	—	—	0.01
After cumulative effect of accounting change	0.37	0.19	0.38	0.20	1.13
Cash distributions per common unit[2]	$ 0.475	$ 0.500	$ 0.513	$ 0.513	$ 2.000

(1) The sum of the four quarters does not equal the total year due to rounding.

(2) Represents cash distributions declared per common unit for the period indicated. Distributions were paid in the following calendar quarter.

Note 17—Operating Segments

Our operations consist of two operating segments: (1) Pipeline Operations—engages in interstate and intrastate crude oil pipeline transportation and certain related merchant activities; (2) Gathering, Marketing, Terminalling and Storage Operations—engages in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets. We evaluate segment performance based on gross margin and gross profit (gross margin less general and administrative expenses).

	Pipeline	Gathering Marketing, Terminalling & Storage	Total
		(in millions)	
Twelve Months Ended December 31, 2002			
Revenues:			
External Customers	$ 462.4	$ 7,921.8	$8,384.2
Intersegment[(a)]	23.8	—	23.8
Total revenues of reportable segments	$ 486.2	$ 7,921.8	$8,408.0
Segment gross margin[(b)]	$ 83.9	$ 90.4	$ 174.3
General and administrative expenses[(c)(d)]	13.2	31.5	44.7
Segment gross profit[(e)]	$ 70.7	$ 58.9	$ 129.6
Capital expenditures	$ 340.2	$ 23.3	$ 365.2
Total assets	$1,030.7	$ 635.9	$1,666.6
Maintenance capital	$ 3.4	$ 2.6	$ 6.0
Twelve Months Ended December 31, 2001			
Revenues:			
External Customers	$ 339.9	$ 6,528.3	$6,868.2
Intersegment[(a)]	17.5	—	17.5
Total revenues of reportable segments	$ 357.4	$ 6,528.3	$6,885.7
Segment gross margin[(b)]	$ 71.3	$ 71.0	$ 142.3
General and administrative expenses[(c)(d)]	12.4	28.5	40.9
Segment gross profit[(e)]	$ 58.9	$ 42.5	$ 101.4
Capital expenditures	$ 169.8	$ 80.4	$ 250.2
Total assets	$ 472.3	$ 788.9	$1,261.2
Maintenance capital	$ 0.5	$ 2.9	$ 3.4
Twelve Months Ended December 31, 2000			
Revenues:			
External Customers	$ 505.7	$ 6,135.5	$6,641.2
Intersegment[(a)]	68.7	—	68.7
Total revenues of reportable segments	$ 574.4	$ 6,135.5	$6,709.9
Gain on sale of assets	$ 48.2	$ —	$ 48.2
Segment gross margin[(b)]	51.8	75.9	127.7
General and administrative expenses[(c)(d)]	12.7	25.0	37.7
Segment gross profit[(e)]	$ 39.1	$ 50.9	$ 90.0
Capital expenditures	$ 1.5	$ 11.1	$ 12.6
Total assets	$ 324.8	$ 561.0	$ 885.8
Maintenance capital	$ 0.4	$ 1.4	$ 1.8

Table continued on following page

(a) Intersegment sales were conducted on an arm's length basis.
(b) Gross margin is calculated as revenues less cost of sales and operations expense. The 2001 gross margin includes the impact of the $5.0 million inventory valuation adjustment.
(c) G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segment based on the business activities that exist at that time. For comparison purposes, we have reclassified G&A expenses by segment for all periods presented to conform to the refined presentation used in 2002. The proportional allocation by segment will continue to be based on the business activities that exist during each period.
(d) In 2002, $1.0 million write-off of deferred acquisition-related costs was excluded as it is not attributable to the segments. Also, $5.7 million and $3.1 million of non cash compensation expense in 2001 and 2000, respectively, was excluded as it is not allocated to the segments.
(e) Gross profit is calculated as revenues less costs of sales and operations expenses and general and administrative expenses, excluding noncash compensation expense.

Geographic Data

Prior to 2001, all of our revenues were derived from, and our assets located in, the United States. During 2001, we expanded into Canada (see Note 4). Set forth below is a table of 2002 and 2001 revenues and long lived assets attributable to these geographic areas (in millions):

	For the Year Ended December 31,	
	2002	2001
Revenues		
United States	$ 6,941.7	$ 6,149.8
Canada	1,442.5	718.4
	$ 8,384.2	$ 6,868.2

	As of December 31,	
	2002	2001
Long-Lived Assets		
United States	$ 866.9	$ 567.6
Canada	194.1	188.2
	$ 1,061.0	$ 755.8

Exhibit 21.1

Subsidiaries and Partnerships of Plains All American Pipeline, L.P.

Corporations

- Plains Marketing GP Inc.
- PMC (Nova Scotia) Company

Partnerships

- Plains Marketing, L.P.
- All American Pipeline, L.P.
- Plains AAP, L.P.
- Basin Pipeline Holdings, L.P.
- Rancho Pipeline Holdings, L.P.

Limited Liability Companies

- Plains All American GP LLC
- Plains Marketing Canada LLC
- Basin Pipeline Holdings GP LLC
- Rancho Pipeline Holdings GP LLC

Exhibit 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 333-91141, 333-54118, 333-74920) and Form S-3 (Nos. 333-59224, 333-68446) of Plains All American Pipeline L.P. of our report dated February 26, 2003, relating to the consolidated financial statements, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2003