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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2004

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 (State or other jurisdiction of incorporation or organization)	**76-0582150** (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 amendments 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 $1.5 billion on June 30, 2004, based on $33.38 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 25, 2005, there were outstanding 67,868,108 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K—2004 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 our pipeline system;
- the success of our risk management activities;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;
- successful integration and future performance of acquired assets or businesses;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- maintenance of our credit rating and ability to receive open credit from our suppliers;
- declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- successful third party drilling efforts in areas in which we operate pipelines or gather crude oil;
- demand for various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;
- fluctuations in refinery capacity in areas supplied by our transmission lines;
- the effects of competition;
- continued creditworthiness of, and performance by, counter parties;
- the impact of crude oil price fluctuations;
- the impact of current and future laws, rulings and governmental regulations;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- the currency exchange rate of the Canadian dollar;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our Long-Term Incentive Plan; and
- general economic, market or business conditions.

Other factors described herein, 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, formed in 1998 and engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and natural gas related petroleum products. We refer to liquefied petroleum gas and natural gas related petroleum products collectively as "LPG." We have an extensive network of pipeline transportation, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada. Our operations can be categorized into two primary business activities:

- *Crude Oil Pipeline Transportation Operations*. As of December 31, 2004, we owned approximately 15,000 miles of active gathering and mainline crude oil pipelines located throughout the United States and Canada, of which approximately 13,000 miles are included in our pipeline segment. 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*. As of December 31, 2004, we owned approximately 37 million barrels of active above ground crude oil terminalling and storage facilities, including approximately 23.4 million barrels of tankage that are associated with our pipeline operations within our pipeline segment. 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. We utilize our storage tanks to counter-cyclically balance our gathering and marketing operations and to execute various hedging strategies to stabilize profits and reduce the negative impact of crude oil market volatility. Our terminalling and storage operations also generate revenue at the Cushing Interchange and our other locations through a combination of storage and throughput charges to third parties. We also own approximately 1.7 million barrels of LPG storage. Our gathering and marketing operations include:

  - the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as foreign cargoes;

  - 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, the storage of LPG at storage facilities owned by us or third parties and the sale of LPG to wholesalers, retailers and industrial end users.

Business Strategy

Our principal business strategy is to capitalize on the regional crude oil supply and demand imbalances that exist in the United States and Canada by combining the strategic location and distinctive 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 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;
- utilizing assets we have recently acquired along the Gulf Coast and our Cushing Terminal to increase our presence in the importation of foreign crude through Gulf of Mexico receipt facilities to U.S. refiners;
- selectively pursuing strategic and accretive acquisitions of crude oil transportation assets, including pipelines, gathering systems, terminalling and storage facilities and other assets that complement our existing asset base and distribution capabilities;
- optimizing and expanding our Canadian operations and our presence in certain areas of the U.S. to take advantage of anticipated increases in the volume and qualities of crude oil produced in these areas as well as increased foreign crude import activities in the Gulf Coast area; and
- prudently and economically leveraging our asset base, knowledge base and skill sets to participate in energy businesses that are closely related to, or significantly intertwined with, the crude oil business.

To a lesser degree, we also engage in a similar business strategy with respect to the wholesale marketing and storage of LPG.

Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success is our ability to maintain a competitive cost of capital and access to the capital markets. We have consistently communicated to the financial community our intention to maintain a strong credit profile that we believe is consistent with 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 55% or less;
- an average long-term debt-to-EBITDA ratio of approximately 3.5x or less (EBITDA is earnings before interest, taxes, depreciation and amortization); and,
- an average EBITDA-to-interest coverage ratio of approximately 3.3x or better.

Based on our 2004 results, we were slightly above our targeted metric for long-term debt-to-EBITDA primarily due to acquisitions made at various times throughout the year, and the inclusion of less than a full year's results in EBITDA. 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. In certain cases, acquisitions will initially be financed using debt since it is difficult to predict the actual timing of accessing the market to raise equity. Accordingly, from time to time we may be outside the parameters of our targeted credit profile.

Credit Rating

As of February 2005, our senior unsecured rating with Standard & Poors and Moody's Investment Services was BBB- stable and Baa3 stable, respectively, both of which are investment grade. We cannot assure you that these ratings will remain in effect for any given period of time or that one or both of these ratings will not be lowered or withdrawn entirely by a rating agency. Note that a credit rating is not a recommendation to buy, sell or hold securities, and may be revised or withdrawn at any time.

Competitive Strengths

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

- ***Our pipeline assets are strategically located and have additional capacity.*** Our primary crude oil pipeline transportation and gathering assets are located in well-established 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. In many instances, these assets are strategically positioned to maximize the value of crude oil by transporting it to major trading locations and premium markets. Certain of our pipeline networks currently possess additional capacity that can accommodate increased demand without significant additional capital investment.

- ***Our Cushing Terminal is strategically located and operationally flexible.*** 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 one of the most modern large-scale terminalling and storage facilities at the Cushing Interchange, incorporating operational enhancements designed with the ability to safely and efficiently terminal, store, blend and segregate large volumes and multiple varieties of crude oil as well as with extensive environmental safeguards. Since becoming operational in late 1993, we have completed four separate expansion phases, increasing the Cushing Terminal's tankage to 6.3 million barrels. In January 2005, we announced the commencement of our Phase V expansion that will increase the Cushing Terminal's capacity by approximately 1.1 million barrels. In addition, we own approximately 31 million barrels of above-ground crude oil terminalling and storage assets elsewhere in the United States and Canada that are used in our pipeline operations or 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 various 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 this balance of activities, combined with our 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, to borrow under our credit facilities and to issue additional notes in the long-term debt capital markets. As of December 31, 2004, we had approximately $420.2 million available under our committed credit facilities, subject to covenant compliance.

- ***We have an experienced management team whose interests are aligned with those of our unitholders.*** 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 collectively own approximately 650,000 common units. In addition, through grants of phantom units and options, the senior management team also owns significant contingent equity incentives that generally vest upon achievement of performance objectives, continued service or, in certain cases, both.

Organizational History

We were formed as a master limited partnership in September 1998 to acquire and operate midstream crude oil businesses and assets. We completed our initial public offering in November 1998. Since June 2001, our 2% general partner interest has been 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. 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. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners. See "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters—Beneficial Ownership of General Partner Interest."

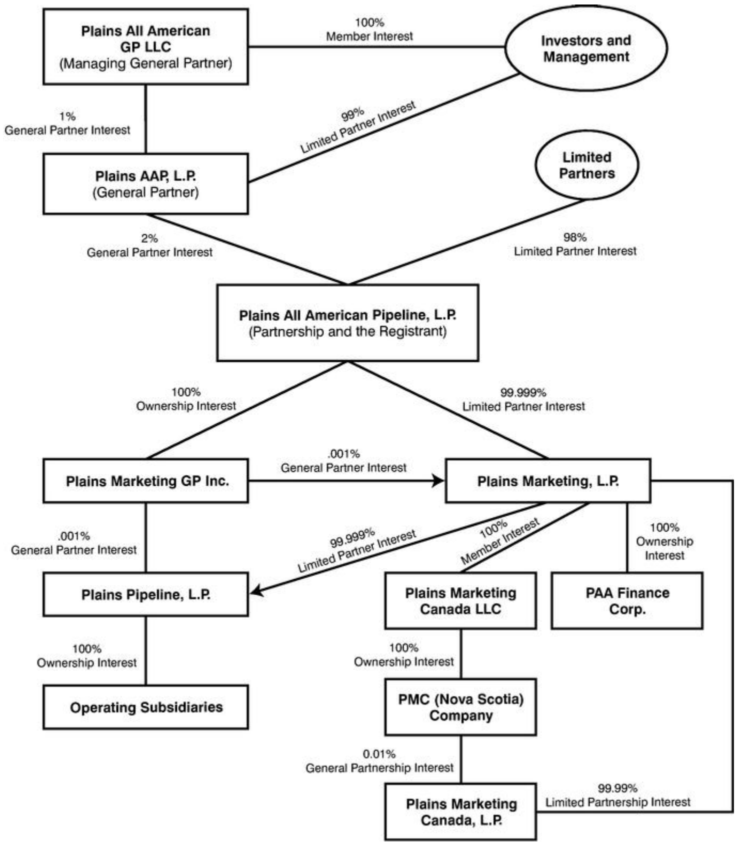
Partnership Structure and Management

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 Plains Pipeline, L.P. Our Canadian and LPG 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. Plains All American GP LLC is governed by an eight-member board of directors. As amended in July 2004, the limited liability company agreement provides that four directors are designated by the four owners that hold 9% or greater of the outstanding membership interests of Plains All American GP LLC, one director is the Chairman and CEO and three independent directors are elected by majority vote of the membership owners of Plains All American GP LLC. Our general partner does not receive a 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.

The chart on the next page depicts the current structure and ownership of Plains All American Pipeline, L.P. and certain subsidiaries.

Partnership Structure



Acquisitions

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. Such assets and operations include crude oil related assets and LPG assets, as well as energy assets that are closely related to, or intertwined with, these business lines, and enable us to leverage our asset base, knowledge base and skill sets. We have established a target to complete, on average, $200 million to $300 million in acquisitions per year, subject to availability of attractive assets on acceptable terms. Since 1998, and through December 31, 2004, we have completed numerous acquisitions for an aggregate purchase price of approximately $1.9 billion. In addition, from time to time, we have sold assets that are no longer considered essential to our operations.

The following table summarizes selected acquisitions that we have completed over the past five years:

Acquisition	Date	Description	Approximate Purchase Price (in millions)
Schaefferstown Propane Storage Facility	August 2004	Storage capacity of approximately 0.5 million barrels of refrigerated propane	$32
Cal Ven Pipeline System	May 2004	195-miles of gathering and mainline crude oil pipelines in northern Alberta	$19
Link Energy LLC	April 2004	The North American crude oil and pipeline operations of Link Energy, LLC ("Link")	$332
Capline and Capwood Pipeline Systems	March 2004	An approximate 22% undivided joint interest in the Capline Pipeline System and an approximate 76% undivided joint interest in the Capwood Pipeline System	$158
South Saskatchewan Pipeline System	November 2003	A 158-mile mainline crude oil pipeline and 203 miles of gathering lines in Saskatchewan	$48
ArkLaTex Pipeline System	October 2003	240 miles of crude oil gathering and mainline pipelines and 470,000 barrels of crude oil storage capacity	$21
Iraan to Midland Pipeline System	June 2003	98-mile mainline crude oil pipeline	$18
South Louisiana Assets	June 2003 and December 2003	Various terminalling and gathering assets in South Louisiana, including a 100% interest in Atchafalaya Pipeline, L.L.C.	$18

Iatan Gathering System	March 2003	West Texas crude oil gathering system	$24
Red River Pipeline System	February 2003	334-mile crude oil pipeline along with 645,000 barrels of crude oil storage capacity	$19
Shell West Texas Assets	August 2002	Basin Pipeline System, Permian Basin Pipeline System and the Rancho Pipeline System	$324
Canadian Operations	May/July 2001	The assets of CANPET Energy Group (crude oil and LPG marketing) and substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. (560 miles of crude oil and condensate mainlines along with 1.1 million barrels of crude oil storage and terminalling capacity)	$232

The following is a more in-depth discussion of selected acquisitions completed in 2004:

Schaefferstown Propane Storage Facility

In August 2004, we completed the acquisition of the Schaefferstown Propane Storage Facility from Koch Hydrocarbon, L.P. The total purchase price was approximately $32 million, including transaction costs. In connection with the transaction, the Partnership also acquired an additional $14.2 million of inventory. The transaction was funded through a combination of cash on hand and borrowings under the Partnership's revolving credit facilities. The storage facility is located approximately 65 miles northwest of Philadelphia near Schaefferstown, Pennsylvania, and has the capacity to store approximately 0.5 million barrels of refrigerated propane. In addition, the facility has 19 bullet storage tanks with an aggregate capacity of approximately 14,000 barrels. Propane is delivered to the facility via truck or pipeline and is transported out of the facility by truck. In addition, the transaction also included approximately 61 acres of land and a truck rack. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our gathering, marketing, terminalling and storage operations segment since August 25, 2004.

Cal Ven Pipeline System

On May 7, 2004, we completed the acquisition of the Cal Ven Pipeline System from Cal Ven Limited, a subsidiary of Unocal Canada Limited. The total purchase price was approximately $19 million, including transaction costs. The Cal Ven Pipeline System includes approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The system is located in northern Alberta and has the ability to deliver crude oil into the Rainbow Pipeline System. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our pipeline operations segment since May 1, 2004.

Link Energy LLC

On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition-related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allowed us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions. The results of operations and assets from this acquisition have been included in our consolidated financial statements and both our pipeline operations and gathering, marketing, terminalling and storage operations segments since April 1, 2004.

Capline and Capwood Pipeline System

In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's ("SPLC") interests in two entities for approximately $158.0 million in cash (including a $15.8 million deposit paid in December 2003) and approximately $0.5 million of transaction and other costs. The principal assets of the entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline system is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing over 2.7 million barrels of refining capacity in PADD II. Capline has direct connections to a significant amount of sweet and light sour crude production in the Gulf of Mexico. In addition, with its two active docks capable of handling 600,000-barrel tankers as well as access to LOOP, the Louisiana Offshore Oil Port, the Capline System is a key transporter of both domestic and foreign crude to PADD II. The total system operating capacity is 1.14 million barrels per day, with approximately 248,000 barrels per day subject to the interest acquired. Since we acquired this asset, throughput on the interest we acquired averaged approximately 147,000 barrels per day.

The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The Capwood system has an operating capacity of 277,000 barrels per day of crude oil. Of that capacity, approximately 211,000 barrels per day are subject to the interest acquired. Since we acquired this asset, throughput on the interest we acquired averaged approximately 120,000 barrels per day. The Capwood System has the ability to deliver crude at Wood River to PADD II refineries and pipelines. Movements on the Capwood system are driven by the volumes shipped on Capline as well as Canadian crude that can be delivered to Patoka via the Mustang Pipeline. Since closing, we have assumed the operatorship of the Capwood system from SPLC.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil related assets and LPG assets, as well as energy assets that are closely related to, or intertwined with, these business lines, and enable us to leverage our asset base, knowledge base and skill sets. 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 in which we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations.

Dispositions

Shutdown and Sale of Rancho Pipeline System

We acquired an interest in the Rancho Pipeline System from Shell in August 2002. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminated in March 2003. Upon termination, the agreement required the owners to take the pipeline system, in which we owned an approximate 50% interest, out of service. Accordingly, we notified our shippers and did not accept nominations for movements after February 28, 2003. This shutdown was contemplated at the time of the acquisition and was accounted for under purchase accounting in accordance with SFAS No. 141 "Business Combinations." The pipeline was shut down on March 1, 2003 and a purge of the crude oil linefill was completed in April 2003. In June 2003, we completed transactions whereby we transferred our ownership interest in approximately 241 miles of the total 458 miles of the pipeline in exchange for $4.0 million and approximately 500,000 barrels of crude oil tankage in West Texas. In August 2004, we sold our interest in the remaining portion of the system for approximately $0.9 million, including the assumption by the purchaser of all liabilities typically associated with pipelines of this type. We recognized a gain of approximately $0.6 million on this transaction.

All American Pipeline Linefill Sale and Asset Disposition

In March 2000, we sold the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas for $129.0 million. 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.

Description of Segments and Associated Assets

Our business activities are conducted through two primary segments, Pipeline Operations and Gathering, Marketing, Terminalling and Storage Operations ("GMT&S"). Our operations are conducted in approximately 40 states in the United States and six provinces in Canada.

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

Pipeline Operations

As of December 31, 2004, we owned approximately 15,000 miles of active gathering and mainline crude oil pipelines located throughout the United States and Canada. Approximately 13,000 miles of these pipelines are used in our pipeline operations segment with the remainder used in our GMT&S segment. Our activities from pipeline operations generally consist of transporting crude oil for a fee and third-party leases of pipeline capacity, as well as barrel exchanges and buy/sell arrangements.

Substantially all of our pipeline systems are controlled or monitored 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 into and delivered through the pipelines, product flow rates, and pressure and temperature variations. 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, satellite, radio or a combination thereof to provide communications for remote monitoring and in some instances 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 cathodic protection, corrosion inhibiting chemicals injected into the crude stream and other protection systems typically used in the industry. 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, provincial and local laws and regulations, standards prescribed by the American Petroleum Institute, the Canadian Standards Association and accepted industry practice. See "—Regulation—Pipeline and Storage Regulation."

Major Pipeline Assets

All American Pipeline System

The All American Pipeline is a common carrier crude oil pipeline system that transports crude oil produced from certain outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system extends approximately 10 miles along the California coast from Las Flores to Gaviota (24-inch diameter pipe) and continues from Gaviota approximately 126 miles to our station in Emidio, California (30-inch diameter 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. The system is subject to tariff rates regulated by the FERC.

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 that 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 that 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 filed 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 "Certain Relationships and Related Transactions—Transactions with Related Parties—General." The third party pays the same tariff as required in the transportation agreements. For 2003 and 2004, the tariffs averaged $1.71 per barrel and $1.81 per barrel, respectively. Effective January 1, 2005, based on the contractual escalator, the average tariff increased to $1.88 per barrel. The agreements do not require these owners to transport a minimum volume.

A significant portion of our revenues less direct field operating costs is derived from the pipeline transportation business associated with these two fields. The relative contribution to our revenues less direct field operating costs from these fields has decreased from approximately 24% in 2000 to 11% in 2004, as we have grown and diversified through acquisitions and organic expansions and as a result of declines in volumes produced and transported from these fields. Since our acquisition in 1998, the volume decline has been substantially offset 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 44,000 and 10,000 average daily barrels, respectively, for 2004. 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 segment profit of approximately $3.2 million, based on a tariff of $1.88 per barrel.

In October 2004, PXP announced that it had successfully completed an initial development well into the Rocky Point field that is accessible from the Point Arguello platforms and that drilling operations are underway on a second development well. If successful, such incremental drilling activity could lead to increased volumes on our All American Pipeline System in future periods. However, we can give no assurance that our volumes transported would increase as a result of this drilling activity.

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

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(barrels in thousands)				
Average daily volumes received from:					
Point Arguello (at Gaviota)	10	13	16	18	18
Santa Ynez (at Las Flores)	44	46	50	51	56
Total	54	59	66	69	74

Basin Pipeline System

The Basin Pipeline System, in which we own an approximate 87% undivided joint interest, is a primary route for transporting Permian Basin crude oil to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. We acquired the Basin Pipeline System in August 2002. Since acquisition, we have been the operator of the system. The Basin system is a 515-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 265,000 barrels per day (net to our interest) during 2004. Within the current operating range, a 20,000 barrel per day decline in volumes shipped on the Basin system would result in a decrease in annual pipeline segment profit of approximately $1.8 million.

The Basin system consists of three primary movements of crude oil: (i) 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; (ii) barrels are shipped to the Mid-Continent region on the Midland to Wichita Falls segment and the Wichita Falls to Cushing segment; and (iii) foreign and Gulf of Mexico barrels are delivered into Basin at Wichita Falls and delivered to a connecting carrier or shipped to Cushing for further distribution to Mid-Continent or Midwest refineries. The 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.

In 2004, we expanded a 424-mile section of the system extending from Midland, Texas to Cushing, Oklahoma. With the completion of this expansion, the capacity of this section has increased approximately 15%, from 350,000 barrels per day to approximately 400,000 barrels per day. The Basin system is subject to tariff rates regulated by the Federal Energy Regulatory Commission (the "FERC"). TEPPCO Partners, L.P. owns the remaining approximately 13% interest in the system.

Capline/Capwood Pipeline Systems

The Capline Pipeline System, in which we own a 22% undivided joint interest, is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline Pipeline System is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing over 2.7 million barrels of refining capacity in PADD II. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, with its two active docks capable of handling 600,000-barrel tankers as well as access to LOOP, it is a key transporter of sweet and light sour foreign crude to PADD II. With a total system operating capacity of 1.14 million barrels per day of crude oil, approximately 248,000 barrels per day are subject to our interest. Since we acquired this asset in March 2004, throughput on the interest acquired has averaged approximately 147,000 barrels per day. A 10,000 barrel per day decline in volumes shipped on the Capline system would result in a decrease in annual pipeline segment profit of approximately $1.5 million.

The Capwood Pipeline System, in which we own a 76% undivided joint interest, is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The Capwood Pipeline System has an operating capacity of 277,000 barrels per day of crude oil. Of that capacity, approximately 211,000 barrels per day are subject to our interest. The system has the ability to deliver crude oil at Wood River to several other PADD II refineries and pipelines. Movements on the Capwood system are driven by the volumes shipped on Capline as well as Canadian crude that can be delivered to Patoka via the Mustang Pipeline. PAA assumed the operatorship of the Capwood system from SPLC. Since we acquired this asset in March 2004, throughput net to our interest acquired has averaged approximately 120,000 barrels per day.

Our significant pipeline systems are discussed on the previous pages. Following is a tabular presentation of all of our active pipeline assets in the United States and Canada, grouped by geographic location and including the aforementioned major pipeline assets:

Region	Pipeline	Ownership Percentage	Pipeline Mileage	2004 Average Net Volumes
Southwest US	Basin	87.0%	515	265,000
	West Texas Gathering	100.0%	717	80,000
	Permian Basin	100.0%	919	46,000
	Dollarhide	100.0%	24	6,000
	Mesa	8.8%	79	28,000
	Iraan	100.0%	98	23,000
	Iatan	100.0%	360	22,000
	New Mexico	100.0%	1,185	50,000
	Texas	100.0%	1,276	80,000
	Lefors	100.0%	68	2,000
	Merkel	100.0%	128	1,000
Western US	All American	100.0%	136	54,000
	San Joaquin Valley	100.0%	86	74,000
US Rocky Mountains	Butte	22.0%	370	15,000
	North Dakota	100.0%	620	39,000
US Gulf Coast	Sabine Pass	100.0%	33	15,000
	Ferriday	100.0%	570	7,000
	La Gloria	100.0%	114	23,000
	Red River	100.0%	567	12,000
	ArkLaTex	100.0%	161	7,000
	Atchafalaya	100.0%	35	14,000
	Eugene Island	100.0%	66	12,000
	Bridger Lakes	100.0%	17	3,000
	Capline	22.0%	633	123,000
	Capwood/Patoka	76.0%	57	109,000
	Pearsall	100.0%	62	2,000
	Mississippi/Alabama	100.0%	686	29,000
	Southwest Louisiana	100.0%	267	4,000
Central US	Oklahoma	100.0%	1,498	56,000
	Midcontinent	100.0%	1,196	22,000
Canada	Cal Ven	100.0%	177	11,000
	Manito	100.0%	101	71,000
	Milk River	100.0%	11	106,000
	Cactus Lake	14.9%	55	3,000
	Wascana	100.0%	114	9,000
	Wapella	100.0%	79	14,000
	South Sask	100.0%	158	49,000

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 generally provides us with the flexibility to maintain our 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, trading locations as well as foreign cargoes brought in by tanker;
- transporting crude oil on our own proprietary gathering assets and our common carrier pipelines or, when necessary or cost effective, assets owned and operated by third parties;
- exchanging 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 often with lower margins than pipeline and terminalling and storage operations.

The following table shows the average daily volume of our lease gathering and bulk purchases for the past five years:

	Year Ended December 31,				
	2004	2003	2002	2001	2000
			(barrels in thousands)		
Lease gathering	589	437	410	348	262
Bulk purchases	148	90	68	46	28
Total volumes per day	737	527	478	394	290

Crude Oil Purchases. We purchase crude oil from producers under contracts, the majority of which 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 approaching capacity, the producer contacts our field personnel to purchase and transport the crude oil to market. We utilize our truck fleet and gathering pipelines as well as third-party pipelines, trucks and barges to transport the crude oil to market. We own or lease approximately 400 trucks used for gathering crude oil.

We currently have a marketing agreement with PXP for certain of its equity crude oil production and that of its subsidiaries. The marketing agreement provides that we will purchase PXP's equity crude oil production for resale at market prices, for which we charge a fee of $0.20 per barrel. For any new contracts for the sale of the crude oil entered into after January 1, 2005, the marketing fee will be adjusted to $0.15 per barrel, subject to further adjustment in November 2007 based upon then existing market conditions. See "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 current detailed 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. The majority of these contracts are at market prices and have 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 or 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 segment profit 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. In November 1999, we discovered a significant violation of this policy. As a result, we incurred an aggregate loss of approximately $181 million in unauthorized trading losses, including associated costs and legal expenses.

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 market and store LPG and other petroleum products in the United States and Canada. 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, refineries and storage locations. 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 current detailed 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 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 segment profit 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 our own storage facilities and 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 250,000 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 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 and LPG for resale and require significant extensions of credit by our suppliers of crude oil and LPG. In order to assure our ability to perform our obligations under crude oil purchase agreements, various credit arrangements are negotiated with our suppliers. These arrangements include open lines of credit directly with us, and standby letters of credit issued under our senior unsecured revolving credit facility.

When we sell crude oil and LPG, 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.

Because our typical crude oil 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. Generally, sales of crude oil are settled within 30 days of the month of delivery (in the case of foreign cargoes, typically 10 days after delivery), and pipeline, transportation and terminalling services also settle within 30 days from invoice for the provision of services.

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 approximately $2 per barrel to 100% of their contracted amounts. Generally, sales of LPG are settled within 30 days of the date of invoice.

Terminalling and Storage Operations

We own approximately 37 million barrels of terminalling and storage assets. Approximately 13.6 million barrels of capacity are used in our GMT&S segment, and the remaining 23.4 million barrels are used in our Pipeline segment. 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; and
- pipeline operators, refiners or traders that need segregated tankage for foreign cargoes.

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).

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, with an initial tankage capacity of 2 million barrels, 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." Since 1999, we have completed four separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 6.3 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks and sixteen 270,000-barrel tanks, all of which are used to store and terminal crude oil. In January 2005, we announced the commencement of our Phase V expansion that will add approximately 1.1 million barrels of storage capacity to our Cushing Terminal. 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 increase in volumes and varieties of foreign and domestic crude oil projected to be transported through the Cushing Interchange, we incorporated certain attributes into the original 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. Our tankage in Cushing ranges in age from less than a year old to approximately 11 years old and the average age is approximately 5 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.

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. 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 a 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.

We also own LPG storage facilities located in Alto, Michigan, Schaefferstown, Pennsylvania and Claremont, New Hampshire. The Alto facility is approximately 20 miles southeast of Grand Rapids. The Alto facility was acquired from Ohio-Northwest Development Inc. in 2003 and is capable of storing over 1.2 million barrels of LPG. The Schaefferstown facility is approximately 65 miles northwest of Philadelphia and is capable of storing over 0.5 million barrels of propane. The Claremont facility is on the Vermont border and has the capacity to store approximately 17,000 barrels of propane. In addition, the Claremont facility has two truck loading stations and two rail unloading stations. We believe these facilities will further support the expansion of our LPG business in Canada and the northern tier of the U.S. as we combine the facilities' existing fee-based storage business with our wholesale propane marketing expertise. In addition, there may be opportunities to expand these facilities as LPG markets continue to develop in the region.

Crude Oil Volatility; Counter Cyclical Balance; Risk Management

Crude oil prices have historically been very volatile and cyclical, with NYMEX benchmark prices ranging from a high of over $55 per barrel in October 2004 to as low as $10 per barrel over the last 20 years. Segment profit from terminalling and storage activities is dependent on the crude oil throughput volume, 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. Segment profit 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 segment profit. 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 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 segment profit we receive. Except for the controlled trading program discussed below, 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.

While we seek to maintain a position that is substantially balanced within our crude oil lease purchase and LPG activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. 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 an aggregate of 500,000 barrels of crude oil. This controlled trading 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 exception of the controlled trading 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.

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.

Geographic Data; Financial Information about Segments

See Note 14 "Operating Segments" in "Notes to the Consolidated Financial Statements."

Customers

Marathon Ashland Petroleum ("MAP") accounted for 10%, 12% and 10% of our revenues for each of the three years in the period ended December 31, 2004. BP Oil Supply Company also accounted for 10% of our revenues for the year ended December 31, 2004. No other customers accounted for 10% or more of our revenues during the three years ended December 31, 2004. The majority of the revenues from Marathon Ashland Petroleum and BP Oil Supply Company pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of these customers 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.

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 or owners with joint venture 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. Following is a discussion of certain laws and regulations affecting us. However, due to the myriad of complex federal, state, provincial and local regulations that may affect us, directly or indirectly, you should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Pipeline and Storage Regulation

A substantial portion 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. Federal pipeline safety rules also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations, as well as in Canada under the National Energy Board ("NEB") and provincial agencies.

Since 2000, the DOT has adopted a series of rules requiring operators of interstate pipelines transporting hazardous liquids or natural gas 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 transporting hazardous liquids in high consequence areas are subject to these DOT rules and therefore obligate 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. The DOT rules also require 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. Costs associated with this program were approximately $1.0 million in 2003 and approximately $5 million in 2004. Based on currently available information, our preliminary estimate for 2005 is approximately $8 million. The relative increase in program cost over the last few years is primarily attributable to pipeline segments acquired in 2003 and 2004 (including the Link assets), which are subject to the new rules and for which assessment commenced in 2004. Certain of these costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Our estimates do not include the potential costs associated with assets acquired in the future. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

The DOT is currently considering expanding the scope of its pipeline regulation to include certain gathering pipeline systems that are not currently subject to regulation. This expanded scope would likely include the establishment of additional pipeline integrity management programs for these newly regulated pipelines. The DOT is in the initial stages of evaluating this initiative and we do not currently know what, if any, impact this will have on our operating expenses. However, we cannot assure you that future costs related to the potential programs will not be material. However, even if the DOT does not expand the scope of its pipeline regulation to include pipeline systems not currently regulated, we may still need to upgrade or expand our existing pipeline integrity management programs to remain in compliance with the Federal Water Pollution Control Act and other environmental laws. We could be required to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance, and in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

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.

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 83% of our 37 million barrels are subject to DOT jurisdiction). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required by 2009. Costs associated with this program were approximately $3 million in 2004. Based on currently available information, we anticipate we will spend an approximate average of $6 million per year from 2005 through 2009 in connection with API 653 compliance activities. Such amounts incorporate the costs associated with the assets acquired in 2003 and 2004. Our estimates do not include the potential costs associated with assets acquired in the future. We will continue to refine our estimates as information from our assessments is collected.

We have instituted security measures and procedures, in accordance with DOT guidelines, to enhance the protection of certain of our facilities from terrorist attack. We cannot assure you that these security measures would fully protect our facilities from a concentrated attack. See "—Operational Hazards and Insurance."

In Canada, the NEB and provincial agencies such as the Alberta Energy and Utilities Board and the Saskatchewan Industry and Resources have promulgated regulations similar to the domestic pipeline integrity management rules and API 653 standards. We spent approximately $4.1 million in 2004 in compliance activities. Our preliminary estimate for 2005 is approximately $5.1 million. In addition, we expect to incur compliance costs under other regulations related to pipeline and storage tank integrity, such as operator competency programs, regulatory upgrades to our operating and maintenance systems and environmental upgrades of buried sump tanks. Our preliminary estimate for such costs for 2005 is approximately $0.5 million. Certain of these costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Our estimates do not include the potential costs associated with assets acquired in the future. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

Asset acquisitions are an integral part of our business strategy. As we acquire additional assets, we may be required to incur additional costs in order to ensure that the acquired assets comply with the regulatory standards in the U.S. and Canada.

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 both crude oil pipelines and refined product 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 state 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 ("EPAct"), 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 unless doing so would reduce a rate "grandfathered" by EPAct (see below) below the grandfathered level. 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 EPAct deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct that had not been subject to complaint, protest or investigation during that 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 that a substantial change has occurred since the enactment of EPAct in either the economic circumstances of the oil pipeline, or in the nature of the services provided, that were a basis for the rate. EPAct places no such limit on challenges to a provision of an oil pipeline tariff as unduly discriminatory or preferential.

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld FERC's determination that the rates of an interstate petroleum products pipeline, SFPP, L.P. ("SFPP"), were grandfathered rates under EPAct and that SFPP's shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC's decision applying the *Lakehead* policy, under which the FERC allowed a regulated entity organized as a master limited partnership to include in its cost-of-service an income tax allowance to the extent that entity's unitholders were corporations subject to income tax. On December 2, 2004, the FERC issued a Notice of Inquiry that called for comments regarding whether *BP West Coast* applies broadly or only to the specific facts of that case. We are uncertain what action the FERC ultimately will take in response to the court's disapproval of the FERC's *Lakehead* policy and what effect, if any, such action might have on our rates should they be challenged.

Additionally, in *BP West Coast*, the court remanded to the FERC the issue of whether SFPP's revised cost-of-service without a tax allowance would qualify as a substantially changed circumstance that would justify modification of SFPP's rates. Because the court remanded to the FERC and because the FERC's ruling on the substantially changed circumstances issue will focus on the facts and record presented to it, it is not clear what impact, if any, the opinion will have on our rates or on the rates of other FERC-jurisdictional pipelines organized as tax pass-through entities. Moreover, it is not clear to what extent FERC's actions taken in response to *BP West Coast* will be challenged and, if so, whether they will withstand further FERC or judicial review.

In a subsequent FERC proceeding involving SFPP, certain shippers again challenged SFPP's grandfathered rates on the basis of substantially changed circumstances since the passage of EPAct. On March 26, 2004, the FERC issued an order in that case, finding that some of SFPP's rates were not grandfathered and that there were substantially changed circumstances on certain of their systems. Several of the participants in the proceeding have requested rehearing of the FERC's order, and several participants have filed petitions with the D.C. Circuit for review of the order. FERC and court action on those petitions is pending. We are uncertain whether FERC's order will remain intact and, if it does, what effect, if any, that order might have on our grandfathered rates should they be challenged.

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 segment profit on transportation is produced by rates that are either grandfathered or set by agreement with one or more shippers.

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 both federal and provincial transportation 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, provincial and local tax requirements could lead to the imposition of additional taxes, interest and penalties.

Environmental, Health and Safety Regulation

General

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, provincial and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and even the issuance of injunctions that may restrict or prohibit our operations. Environmental laws and regulations are subject to change, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material affect on our results of operations or earnings. A discharge of hazardous liquids 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 any claims made by neighboring landowners and other third parties for personal injury and property damage.

Water

The U.S. Oil Pollution Act ("OPA") and analogous state and Canadian federal and provincial laws subject 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, resulted from a violation of a federal safety, construction, or operating regulation, or if there is a failure to report a spill or cooperate in the cleanup. We believe that we are in substantial compliance with applicable OPA requirements.

The U.S. Clean Water Act and analogous state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. Permits must be obtained to discharge pollutants into these waters. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants. Although we can give no assurances, 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 and all provinces 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 any such applicable state requirements.

In addition to the costs described above we could also be required to spend substantial sums to ensure the integrity of and upgrade our pipeline systems as a result of oil spills, and in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

Air Emissions

Our operations are subject to the U.S. Clean Air Act and comparable state and provincial laws. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions and operating permits may be required for sources already constructed. We may 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 for sources of air emissions. While we believe that our operations are in substantial compliance with these laws in those areas in which we operate, we can provide no assurance that future compliance obligations will not have a material adverse effect on our financial condition or results of operations.

Canada is a participant in the Kyoto Protocol of the United Nations Framework Convention on Climate Change. The Kyoto Protocol requires participating developed nations such as Canada to reduce their emissions of carbon dioxide and other "greenhouse gases" to five percent below 1990 levels by 2012. As a result, already stringent air emissions regulations applicable to our operations in Canada will be replaced, by 2010, with even stricter requirements. We are currently monitoring the impact on our operations of proposed changes in regulations that will be necessary as a result of Canada's participation in the Protocol.

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 and provincial laws. We are not required to comply with a substantial portion of the RCRA requirements because our operations generate primarily oil and gas wastes, which currently are excluded from consideration as RCRA hazardous wastes. However, it is possible that in the future the exclusion of oil and gas wastes from regulation as RCRA hazardous wastes may be eliminated, in which event, our wastes as well as the wastes of our competitors in the oil and gas industry will be subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses for us and the industry in general.

Hazardous Substances

The federal Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as "Superfund," and comparable state and provincial 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 strict 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. 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," in which event we may be held 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 released into the environment.

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. OSHA has also been given jurisdiction over enforcement of legislation designed to protect employees who provide evidence in fraud cases from retaliation by their employer.

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts and related regulations. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or public or employee complaint. Additionally, recent legislation directly ties corporate accountability to the Criminal Code of Canada. This legislation enables occupational health and safety ("OH&S") regulators to prosecute organizations and individuals criminally for violations of the regulations. We believe that our operations are in substantial compliance with applicable OH&S requirements.

Endangered Species Act

The federal Endangered Species Act ("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, which costs, restrictions, or bans could have a material adverse effect on our financial condition or results of operations. Similar regulation (the Species Risk Act) applies to our Canadian operations.

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

We currently own or lease properties where hazardous liquids, including hydrocarbons, are being or have been handled. These properties and the hazardous liquids or associated generated wastes disposed thereon may be subject to CERCLA, RCRA and analogous state and Canadian federal and provincial laws. Under such laws, we could be required to remove or remediate hazardous liquids or associated generated wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In addition, we have entered into indemnification agreements with various counterparties in conjunction with several of our acquisitions. Allocation of environmental liability is an issue negotiated in connection with each of our acquisition transactions. In each case, we make an assessment of potential environmental exposure based on available information. Based on that assessment and relevant economic and risk factors, we determine whether to negotiate an indemnity, what the terms of any indemnity should be (for example, minimum thresholds or caps on exposure) and whether to obtain insurance, if available. In some cases, we have received contractual protections in the form of environmental indemnifications from several predecessor operators for properties acquired by us that are contaminated as a result of historical operations. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply and have term and total dollar limits.

The acquisitions we completed in 2003 and 2004 include a variety of provisions dealing with the allocation of responsibility for environmental costs that range from no or limited indemnities from the sellers to indemnification from sellers with defined limitations on their maximum exposure. We have not obtained insurance for any of the conditions related to our 2003 acquisitions, and only in limited circumstances for our 2004 acquisitions.

For instance, in connection with the Link acquisition, we identified a number of environmental liabilities, for which we received a purchase price reduction from Link. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico ("TNM") pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we will bear $11 million of the first $20 million of pre-May 1999 environmental issues. We will also bear the first $25,000 per site for new sites which were not identified at the time we entered into the agreement (capped at 100 sites). TNM will pay all costs in excess of $20 million (excluding the deductible for new sites). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). We recorded a reserve for environmental liabilities of approximately $17.0 million in connection with the Link acquisition.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, Shell purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a $100,000 deductible per site, an aggregate coverage limit of $70 million, and expires in 2012. Shell has recently made a claim against the policy; however, we do not believe that the claim will substantially reduce our coverage under the policy.

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which occurred prior to the date of the closing of the acquisition. This indemnity applied to claims that exceeded $25,000 individually and $1.0 million in the aggregate. For the indemnity to apply, we were required to assert any claims on or before May 15, 2003. In conjunction with the expiration of this indemnity, we reached agreement with respect to MAP's remaining indemnity obligations. Under the terms of this agreement, MAP will continue to remain obligated for liabilities associated with two Superfund sites at which it is alleged that Scurlock Permian deposited waste oils. In addition, MAP paid us $4.6 million cash as satisfaction of its obligations with respect to other sites. During 2002, we had reassessed previous investigations and completed environmental studies related to environmental conditions associated with our 1999 acquisitions. As a result of that reassessment, we established an additional reserve of $1.2 million.

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

At December 31, 2004, our reserve for environmental liabilities totaled approximately $19.8 million (approximately $12.7 million of this reserve is related to liabilities assumed as part of the Link acquisition). Approximately $9.3 million of our environmental reserve is classified as current and $10.5 million is classified as long-term. At December 31, 2004, we have recorded receivables totaling approximately $6.3 million for amounts recoverable under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. We believe that this reserve is adequate, and in conjunction with our indemnification arrangements, should prevent remediation costs from having a material adverse effect on our financial condition, results of operations, or cash flows. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, no assurances can be made that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations, or cash flows.

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment 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. Since we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such 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, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total assets increasing over 400% since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. Notwithstanding what we believe is a favorable claims history, the overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. As a result, we have elected to self insure more activities against certain of these operating hazards and expect this trend will continue in the future. Certain aspects of these conditions were exacerbated by the events of September 11, 2001, and their overall effect on the insurance industry have adversely impacted the availability and cost of certain coverages. Due to these events, insurers have excluded acts of terrorism and sabotage from our insurance policies and on certain of our key assets, we have elected to purchase 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. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, 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, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. 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, or that we have established adequate reserves to the extent that such risks are not insured.

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 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 1,950 employees at December 31, 2004. 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 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 Canada as well as in most states in the United States. A unitholder may be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes, as well as to file state income tax returns and to pay taxes in various states. A unitholder may be subject to penalties for failure to comply with such requirements. 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 who is not a resident of the state. 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 pertinent states and localities, including the Canadian provinces and Canada, 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.

Unauthorized Trading Loss

In November 1999, we discovered that a former employee had engaged in unauthorized trading activity that resulted in significant losses and litigation and had a temporary, but material adverse impact on our liquidity and our relationship with our customers. 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 in 1999, but also extended into 1998 and required restatements of our financial statements for the applicable periods. Including litigation settlement costs, the aggregate losses associated with this event totaled approximately $181 million. All of the cases were settled and paid. Additionally, based on recommendations from experts involved in the investigation, we made significant enhancements to our systems, policies and procedures and 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. 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 material unauthorized trading that does occur would be detected at an early stage.

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 Securities and Exchange

Commission. We also have on our website our Code of Ethics for Senior Financial Officers, our Code of Business Conduct and our Governance Guidelines. Any waiver of the Code of Ethics for Senior Financial Officers and any waiver of our Code of Business Conduct on behalf of an executive officer or director will also be posted on our website. We also have on our website the committee charters for our Audit, Compensation and Governance Committees. Print versions of the foregoing are available to any unitholder upon request. You can also access Section 16 reports through our website. On September 15, 2004, our Chief Executive Officer submitted to the New York Stock Exchange ("NYSE") the annual certification required by Section 303A.12(a) of the NYSE's Listed Company Manual.

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. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 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 received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, asserted breach of fiduciary duty and breach of contract claims against us, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. (Plains Resources, Inc. is a unitholder and an interest owner in our general partner. See "Security Ownership of Certain Beneficial Owners and Management and Related Unitholders' Matters.") The complaint sought to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. This lawsuit has been settled in principle. The court has approved the settlement and, assuming no appeals are filed, the settlement will become final in March 2005.

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency, the Texas

Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 barrels were recovered from the two respective sites. The unrecovered oil has been or will be removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with each release, including estimated remediation costs, are estimated at approximately $1.7 million and $1.4 million, respectively. We continue to work with the appropriate state and federal environmental authorities in responding to the releases and no enforcement proceedings have been instituted by any governmental authority at this time.

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***

On January 20, 2005, we held a special meeting of our unitholders. At the meeting, our unitholders approved the following matters:

- A proposal to approve (a) a change in the terms of our Class B common units to provide that each Class B common unit is convertible into one of our common units and (b) the issuance of additional common units upon such conversion (36,457,148 "For," 486,532 "Against," 197,686 "Abstain");
- A proposal to approve (a) a change in the terms of our Class C common units to provide that each Class C common unit is convertible into one of our common units and (b) the issuance of additional common units upon such conversion (36,448,165 "For," 492,779 "Against," 200,422 "Abstain");
- A proposal to approve the terms of our 2005 Long-Term Incentive Plan (the "2005 LTIP"), which provides for awards of common units, options to purchase common units and other rights to our employees, officers and directors (39,864,363 "For," 1,336,929 "Against," 493,061 "Abstain"); and
- Any proposal to adjourn the special meeting to a later date, if necessary, to solicit additional proxies if there were not sufficient votes in favor of the foregoing proposals (38,273,033 "For," 3,185,226 "Against," 235,995 "Abstain").

See "Certain Relationships and Related Transactions—Transactions with Related Parties—Class B Common Units" and "Certain Relationships and Related Transactions—Transactions with Related Parties—Class C Common Units" for a discussion of the Class B and Class C common units.

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

The common units are listed and traded on the New York Stock Exchange under the symbol "PAA". On February 24, 2005, the closing market price for the common units was $39.22 per unit and there were approximately 32,000 record holders and beneficial owners (held in street name). As of February 24, 2005, there were 67,293,108 common units outstanding. The number of common units outstanding on this date includes the 3,245,700 Class C common units and the 1,307,190 Class B common units that converted in February 2005.

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		Cash Distributions[1]
	High	Low	
2003			
1st Quarter	$ 26.90	$ 24.20	$ 0.5500
2nd Quarter	31.48	24.65	0.5500
3rd Quarter	32.49	29.10	0.5500
4th Quarter	32.82	29.76	0.5625
2004			
1st Quarter	$ 35.23	$ 31.18	$ 0.5625
2nd Quarter	36.13	27.25	0.5775
3rd Quarter	35.98	31.63	0.6000
4th Quarter	37.99	34.51	0.6125

(1) Cash distributions are paid in the following calendar quarter.

Cash Distribution Policy

We will distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below.

Definition of Available Cash. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

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, 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. We paid $8.3 million to the general partner in incentive distributions in 2004. Our most recent quarterly distribution was $0.6125 per unit. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

Under the terms of the agreements governing our debt, 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."

Item 6. ***Selected Financial and Operating Data***

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2004, 2003, 2002, 2001 and 2000 and for the years then ended. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(in millions except per unit data)				
Statement of operations data:					
Revenues[10]	$ 20,975.5	$ 12,589.8	$ 8,384.2	$ 6,868.2	$ 6,641.2
Cost of sales and field operations (excluding LTIP charge)[10]	(20,641.1)	(12,366.6)	(8,209.9)	(6,720.9)	(6,506.5
Unauthorized trading losses and related expenses	—	—	—	—	(7.0
Inventory valuation adjustment	(2.0)	—	—	(5.0)	—
LTIP charge—operations[1]	(0.9)	(5.7)	—	—	—
General and administrative expenses (excluding LTIP charge)	(75.8)	(50.0)	(45.7)	(46.6)	(40.8
LTIP charge—general and administrative[1]	(7.0)	(23.1)	—	—	—
Depreciation and amortization	(67.2)	(46.8)	(34.0)	(24.3)	(24.5
Total costs and expenses	(20,794.0)	(12,492.3)	(8,289.6)	(6,796.8)	(6,578.8
Gain on sale of assets	0.6	0.6	—	1.0	48.2
Asset impairment	(2.0)	—	—	—	—
Operating income	180.1	98.2	94.6	72.4	110.6
Interest expense	(46.7)	(35.2)	(29.1)	(29.1)	(28.7
Interest and other income (expense), net[2]	(0.3)	(3.6)	(0.2)	0.4	(4.4
Income from continuing operations before cumulative effect of change in accounting principle[2][3]	$ 133.1	$ 59.4	$ 65.3	$ 43.7	$ 77.5
Basic net income per limited partner unit before cumulative effect of change in accounting principle[2][3]	$ 1.94	$ 1.01	$ 1.34	$ 1.12	$ 2.13
Diluted net income per limited partner unit before cumulative effect of change in accounting principle[2][3]	$ 1.94	$ 1.00	$ 1.34	$ 1.12	$ 2.13
Basic weighted average number of limited partner units outstanding	63.3	52.7	45.5	37.5	34.4
Diluted weighted average number of limited partner units outstanding	63.3	53.4	45.5	37.5	34.4
Balance sheet data (at end of period):					
Total assets	$ 3,160.4	$ 2,095.6	$ 1,666.6	$ 1,261.2	$ 885.8
Total long-term debt[4]	949.0	519.0	509.7	354.7	320.0
Total debt	1,124.5	646.3	609.0	456.2	321.3
Partners' capital	1,070.2	746.7	511.6	402.8	214.0

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(in millions except per unit and volume data)				
Other data:					
Maintenance capital expenditures	$ 11.3	$ 7.6	$ 6.0	$ 3.4	$ 1.8
Net cash provided by (used in) operating activities(5)	104.0	115.3	185.0	(16.2)	(33.5)
Net cash provided by (used in) investing activities(5)	(651.2)	(272.1)	(374.9)	(263.2)	211.0
Net cash provided by (used in) financing activities	554.5	157.2	189.5	279.5	(227.8)
Declared distributions per limited partner unit(6)(7)(8)	2.30	2.19	2.11	1.95	1.83
Operating Data:					
Volumes (thousands of barrels per day)(9)					
Pipeline segment:					
Tariff activities					
All American	54	59	65	69	74
Link acquisition	283	N/A	N/A	N/A	N/A
Capline	123	N/A	N/A	N/A	N/A
Basin	265	263	93	N/A	N/A
Other domestic	424	299	219	144	130
Canada	263	203	187	132	N/A
Pipeline margin activities	74	78	73	61	60
Total	1,486	902	637	406	264
Gathering, marketing, terminalling and storage segment:					
Crude oil lease gathering	589	437	410	348	262
Crude oil bulk purchases	148	90	68	46	28
Total	737	527	478	394	290
LPG sales	48	38	35	19	N/A

(1) Compensation expense related to our 1998 Long Term Incentive Plan ("1998 LTIP"), see "Executive Compensation—1998 Long Term Incentive Plan—Phantom Units."

(2) The 2000 period includes $15.1 million related to losses on the early extinguishment of debt previously classified as an extraordinary item. Effective with our adoption of Statement of Financial Accounting Standards ("SFAS") 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" in January 2003, such items are now shown as impacting income from continuing operations. As a result of this reclassification, basic and diluted net income per limited partner unit before cumulative effect of change in accounting principle for 2000 was reduced by $0.44. In addition, effective with the issuance of the Emerging Issues Task Force Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two Class Method under FASB Statement No. 128," the 2000 amount was further reduced by $0.07.

(3) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of our January 1, 2004 change in our method of accounting for pipeline linefill in third party assets would have been $61.4 million, $64.8 million, $38.4 million and $78.2 million for each of the four years ended December 31, 2003, respectively. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $1.05 ($1.04 diluted), $1.33 ($1.33 diluted), $0.97 ($0.97 diluted) and $2.15 ($2.15 diluted) for each of the four years ended December 31, 2003, respectively.

(4) Includes current maturities of long-term debt of $9.0 million and $3.0 million at December 31, 2002 and 2001, respectively, classified as long-term because of our ability and intent to refinance these amounts under our long-term revolving credit facilities.

(5) In conjunction with the change in accounting principle we adopted as of January 1, 2004, we have reclassified cash flows for the years 2003 and prior associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification as cash flows from operating activities.

(6) Distributions represent those declared and paid in the applicable period.

(7) No distributions were declared or paid on subordinated units in the first quarter of 2000. A distribution of $0.45 per unit was declared and paid to holders of common units in that period.

(8) Our general partner is entitled to receive 2% proportional distributions and also incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 6 "Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements."

(9) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

(10) Includes buy/sell transactions, see Note 2 "Summary of Significant Accounting Policies" in the "Notes to the Consolidated Financial Statements."

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes.

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements and Change in Accounting Principle
- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Risk Factors Related to Our Business

Executive Summary

Company Overview

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products. We refer to liquified petroleum gas and other petroleum products collectively as "LPG." We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada.

We are one of the largest midstream crude oil companies in North America. As of December 31, 2004, we owned approximately 15,000 miles of active crude oil pipelines, approximately 37 million barrels of active terminalling and storage capacity and over 400 transport trucks. Currently, we handle an average of over 2.4 million barrels per day of physical crude oil through our extensive network of assets located in major oil producing regions of the United States and Canada. Our operations consist of two operating segments: (i) pipeline operations ("Pipeline Operations") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets.

Overview of Operating Results and Significant Activities

During 2004, we recognized net income and earnings per limited partner unit of $130.0 million and $1.89, respectively, both of which were substantial increases over 2003 and 2002. The results for 2004 as compared to the two previous years include significant contributions from acquisitions completed during 2003 and 2004.

The following significant activities impacted our operations, operating results or our financial position during 2004:

- Effective April 1, 2004, we acquired all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million. Additionally, effective March 1, 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.5 million (including a $15.8 million deposit paid in December 2003). The principal assets of the Shell entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System.

- We maintained the relative strength of our overall capital structure and maintained substantial liquidity through a series of equity issuances and senior notes issuances. We also entered into new credit facilities which expanded and extended the size and maturity of our prior facilities. See "—Liquidity and Capital Resources."

- We realized year over year growth in segment profit from both our pipeline operations segment and our GMT&S segment. This growth was primarily driven by (i) the impact of the current year acquisitions subsequent to their acquisition during 2004, (ii) inclusion of a full year contribution from those assets that we acquired during 2003, and (iii) the positive results, in relatively volatile market conditions, of our counter-cyclically balanced activities in our GMT&S segment.

- We changed our method of accounting for pipeline linefill in third party assets resulting in a cumulative effect of change in accounting principle charge of $3.1 million. See "—Recent Accounting Pronouncements and Change in Accounting Principle."

- Under generally accepted accounting principles, we are required to recognize an expense when vesting of units under our 1998 Long-Term Incentive Plan ("1998 LTIP") becomes probable as determined by management. Our results of operations for 2004 include a charge of $7.9 million.

- Recognized a foreign exchange gain of $5.0 million related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on a net U.S. dollar denominated liability of our Canadian subsidiary. This is primarily attributable to our LPG business, a substantial amount of which is transacted in U.S. Dollars.

- Recognized a lower-of-cost-or-market inventory charge of approximately $2.0 million related to a valuation adjustment on our LPG inventory. This charge is linked to the foreign exchange gain mentioned above, and is effectively a partial reversal of that gain. This is primarily because of a stronger Canadian dollar relative to the U.S. dollar at the date of measurement compared to at the time of purchase.

- Recognized a non-cash gain of approximately $1.0 million resulting from the mark-to-market of open derivative instruments pursuant to Statement of Financial Accounting Standard No. 133, as amended ("SFAS 133").

- Recognized a non-cash charge of approximately $2.0 million associated with taking our pipeline system in the Illinois Basin out of service. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks. As a result, we were able to maintain most of our margins.

Prospects for the Future

We believe we have access to equity and debt capital and that we are well situated to optimize our position in and around our existing assets and to expand our asset base by continuing to consolidate, rationalize and optimize the North American crude oil infrastructure. We have deliberately configured our assets to provide a counter-cyclical balance between our gathering and marketing activities and our terminalling and storage activities. We believe the combination of these balanced activities adds stability to the portion of our business that is highly cyclical, and with our relatively stable, fee-based pipeline assets, enables us to generate stable financial results.

During 2004 we strengthened our business by expanding our asset base through acquisitions and internal growth projects. We operate in a mature industry and believe that our primary source of growth will come from acquisitions, and we believe that there are opportunities for acquisitions. We will continue to pursue the purchase of midstream crude oil assets, and we will also continue to initiate projects designed to optimize crude oil flows in the areas in which we operate. We believe the outlook is positive for, and have a strategic initiative of increasing our participation in, the importing of foreign crude oil, primarily through building a meaningful asset presence to enable us to receive foreign crude oil via the Gulf Coast. We also believe there are opportunities for us to grow our LPG business. In addition, we believe we can, and will pursue opportunities to, leverage our assets, business model, knowledge and expertise into investments in businesses complementary to our crude oil and LPG activities. Although we believe that we are well situated in the North American crude oil infrastructure, we face various operational, regulatory and financial challenges that may impact our ability to execute our strategy as planned. See "—Risk Factors Related to Our Business" for further discussion of these items. We can give 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.

Acquisitions

We completed a number of acquisitions in 2004, 2003 and 2002 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 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.

2004 Acquisitions

In 2004, we completed several acquisitions for aggregate consideration of approximately $549.5 million. The aggregate consideration includes cash paid, estimated transaction costs and assumed liabilities and net working capital items. The following table summarizes our 2004 acquisitions, and a description of each of these follows the table:

Acquisition	Effective Date	Acquisition Cost (in millions)	Operating Segment
Capline and Capwood Pipeline Systems	03/01/04	$ 158.5	Pipeline
Link Energy LLC	04/01/04	332.3	Pipeline/GMT&S
Cal Ven Pipeline System	05/01/04	19.0	Pipeline
Schaefferstown Propane Storage Facility	08/25/04	32.0	GMT&S
Other	various	7.7	GMT&S
Total 2004 Acquisitions		$ 549.5	

Capline and Capwood Pipeline Systems. In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.0 million in cash (including a $15.8 million deposit paid in December 2003) and approximately $0.5 million of transaction and other costs. In December 2003, subsequent to the announcement of the acquisition and in anticipation of closing, we issued approximately 2.8 million common units for net proceeds of approximately $88.4 million, after paying approximately $4.1 million of transaction costs. The proceeds from this issuance were used to pay down the outstanding balances under our revolving credit facility. At closing, the cash portion of this acquisition was funded from cash on hand and borrowings under our revolving credit facility.

The principal assets of the entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The results of operations and assets from this acquisition (the "Capline acquisition") have been included in our consolidated financial statements and in our pipeline operations segment since March 1, 2004. These pipelines provide one of the primary transportation routes for crude oil shipped into the Midwestern U.S. and delivered to several refineries and other pipelines.

The purchase price was allocated as follows (in millions):

Crude oil pipelines and facilities	$	151.4
Crude oil storage and terminal facilities		5.7
Land		1.3
Office equipment and other		0.1
Total	$	158.5

Link Energy LLC. On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link for approximately $332 million, including $268 million of cash and approximately $64 million of net liabilities assumed and acquisition related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allow us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions. The results of operations and assets from this acquisition (the "Link acquisition") have been included in our consolidated financial statements and both our pipeline operations and GMT&S operations segments since April 1, 2004.

The purchase price was allocated as follows and includes goodwill primarily related to Link's gathering and marketing business (in millions):

Cash paid for acquisition[(1)]	$	268.0
Fair value of net liabilities assumed:		
Accounts receivable[(2)]		409.4
Other current assets		1.8
Accounts payable and accrued liabilities[(2)]		(459.6)
Other current liabilities		(8.5)
Other long-term liabilities		(7.4)
Total net liabilities assumed		(64.3)
Total purchase price	$	332.3
Purchase price allocation		
Property and equipment	$	260.2
Inventory		3.4
Linefill		55.4
Inventory in third party assets		8.1
Goodwill		5.0
Other long term assets		0.2
Total	$	332.3

(1) Cash paid does not include the subsequent payment of various transaction and other acquisition related costs.

(2) Accounts receivable and accounts payable are gross and do not reflect the adjustment of approximately $250 million to net settle, based on contractual agreements with our counterparties.

The total purchase price includes (i) $9.4 million in transaction costs, (ii) approximately $7.4 million related to a plan to involuntarily terminate and relocate employees in conjunction with the acquisition, and (iii) approximately $11.0 million related to costs to terminate a contract assumed in the acquisition. These activities are substantially complete and the majority of the related costs have been incurred as of December 31, 2004. In addition, we anticipate making capital expenditures of approximately $28.0 million ($18.0 million in 2005) to upgrade certain of the assets and comply with certain regulatory requirements.

The acquisition was initially funded with cash on hand and borrowings under our existing credit facilities as well as under a new $200 million, 364-day credit facility. In connection with the acquisition, on April 15, 2004, we completed the private placement of 3,245,700 Class C common units to a group of institutional investors. During the third quarter of 2004, we completed a public offering of common units and the sale of unsecured senior notes. A portion of the proceeds from these transactions was used to retire the $200 million, 364-day credit facility.

Cal Ven Pipeline System. On May 7, 2004 we completed the acquisition of the Cal Ven Pipeline System from Cal Ven Limited, a subsidiary of Unocal Canada Limited. The total purchase price was approximately $19 million, including transaction costs. The transaction was funded through a combination of cash on hand and borrowings under our revolving credit facilities. The Cal Ven Pipeline System includes approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The system is located in northern Alberta and delivers crude oil into the Rainbow Pipeline System. The Rainbow Pipeline System then transports the crude south to the Edmonton market, where it can be used in local refineries or shipped on connecting pipelines to the U.S. market. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our pipeline operations segment since May 1, 2004.

Schaefferstown Propane Storage Facility. In August 2004, we completed the acquisition of the Schaefferstown Propane Storage Facility from Koch Hydrocarbon, L.P. The total purchase price was approximately $32 million, including transaction costs. In connection with the transaction, we also acquired an additional $14.2 million of inventory. The transaction was funded through a combination of cash on hand and borrowings under our revolving credit facilities. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our gathering, marketing, terminalling and storage operations segment since August 25, 2004.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration of approximately $159.5 million. The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. The acquisitions were initially financed with borrowings under our credit facilities, which were subsequently repaid with a portion of the proceeds from our equity issuances and the issuance of senior notes. See "—Liquidity and Capital Resources." The businesses acquired during 2003 impacted our results of operations commencing on the effective date of each acquisition as indicated below. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. With the exception of $0.5 million that was allocated to goodwill and other intangible assets and $4.7 million associated with crude oil linefill and working inventory, the remaining aggregate purchase price was allocated to property and equipment. The following table details our 2003 acquisitions (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Red River Pipeline System	02/01/03	$ 19.4	Pipeline
Iatan Gathering System	03/01/03	24.3	Pipeline
Mesa Pipeline Facility	05/05/03	2.9	Pipeline
South Louisiana Assets(1)	06/01/03	13.4	Pipeline/G,M,T,&S
Alto Storage Facility	06/01/03	8.5	G,M,T&S
Iraan to Midland Pipeline System	06/30/03	17.6	Pipeline
ArkLaTex Pipeline System	10/01/03	21.3	Pipeline
South Saskatchewan Pipeline System	11/01/03	47.7	Pipeline
Atchafalaya Pipeline System(2)	12/01/03	4.4	Pipeline
Total 2003 Acquisitions		$ 159.5	

(1) Includes a 33.3% interest in Atchafalaya Pipeline L.L.C.

(2) Includes two acquisitions each for 33.3% interests in Atchafalaya Pipeline L.L.C.

2002 Acquisitions

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 9.0 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") for approximately $324 million. 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 entire purchase price was allocated to property and equipment.

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. The Rancho Pipeline System was taken out of service in March 2003, pursuant to the operating agreement. See "Business and Properties—Dispositions—Shutdown and Sale of Rancho Pipeline System."

Other 2002 Acquisitions. During February and March of 2002, we completed two other acquisitions for aggregate consideration totaling $15.9 million, with effective dates of February 1, 2002 and March 31, 2002, respectively. These acquisitions include an equity interest in a crude oil pipeline company and crude oil gathering and marketing assets.

Critical Accounting Policies and Estimates

Our critical accounting policies are discussed in Note 2 to the Consolidated Financial Statements. 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.

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third-party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. We currently estimate that less than 2% of total annual revenues and cost of sales are recorded using estimates and less than 5% of total quarterly revenues and cost of sales are recorded using estimates. Accordingly, a variance from this estimate of 10% would impact the respective line items by less than 1% on both an annual and quarterly basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Mark-to-Market Accrual. 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 due to a difference in assumptions applied such as the estimate of prevailing market prices, volatility, correlations and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total revenues are based on estimates derived from these models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Contingent Liability Accruals. We accrue reserves for contingent liabilities including, but not limited to, environmental remediation, insurance claims, asset retirement obligations 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. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, costs of medical care associated with worker's compensation and employee health insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 10% in our aggregate estimate for the contingent liabilities discussed above would have an approximate $2.3 million impact on earnings. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

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 period subsequent to the acquisition. In addition, in conjunction with the 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 customer 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 and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Recent Accounting Pronouncements and Change in Accounting Principle

Recent Accounting Pronouncements

Buy/sell transactions. The Emerging Issues Task Force ("EITF") is currently considering Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," ("EITF No. 04-13"), which relates to buy/sell transactions. The issues to be addressed by the EITF are i) under what circumstances should two or more transactions with the same counterparty be viewed as a single nonmonetary transaction within the scope of APB No. 29; and ii) if nonmonetary transactions within the scope of APB No. 29 involve inventory, are there any circumstances under which the transactions should be recognized at fair value.

Buy/sell transactions are contractual arrangements in which we agree to buy a specific quantity and quality of crude oil or LPG to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of crude oil or LPG at a different location, usually with the same counterparty. These arrangements are generally designed to increase our margin through a variety of methods, including reducing our transportation or storage costs or acquiring a grade of crude oil that more closely matches our physical delivery requirement to one of our other customers. The value difference between purchases and sales is referred to as margin and is primarily due to grade, quality or location differentials. All buy/sell transactions result in us making or receiving physical delivery of the product, involve the attendant risks and rewards of ownership, including title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk, and such transactions are settled in cash similar to all other purchases and sales. Accordingly, such transactions are recorded in both revenues and purchases as separate sales and purchase transactions on a "gross" basis.

We believe that buy/sell transactions are monetary in nature and thus outside the scope of APB Opinion No. 29, "Accounting for Nonmonetary Transactions" ("APB No. 29"). Additionally, we have evaluated EITF No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" ("EITF No. 99-19") and, based on that evaluation, we believe that recording these transactions on a gross basis is appropriate. If the EITF were to determine that these transactions should be accounted for as monetary transactions on a gross basis, no change in our accounting policy for buy/sell transactions would be necessary. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions qualifying for fair value recognition and require a net presentation of such transactions, the amounts of revenues and purchases associated with buy/sell transactions would be netted in our consolidated statement of operations, but there would be no effect on operating income, net income or cash flows from operating activities. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions not qualifying for fair value recognition, these amounts of revenues and purchases would be netted in our consolidated statement of operations and there could be an impact on operating income and net income related to the timing of the ultimate sale of product purchased in the "buy" side of the buy/sell transaction. However, we do not believe any impact on operating income, net income or cash flows from operating activities would be material.

Earnings per Unit. In March 2004, the Emerging Issues Task Force issued Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two-Class Method under FASB Statement No. 128." EITF 03-06 addresses a number of questions regarding the computation of earnings per share by companies that have issued securities, other than common stock, that contractually entitle the holder to participate in dividends and earnings of the company when, and if, it declares dividends on its common stock. The issue also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF 03-06 was effective for fiscal periods beginning after March 31, 2004. The adoption of EITF 03-06 may have an impact on earnings per limited partner unit in future periods if net income exceeds distributions or if other participating securities are issued. The effect of applying EITF 03-06 on prior periods was not material except for the year ended December 31, 2000, which has been restated as shown below.

Basic and Diluted Income Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle per Limited Partner Unit:

	For the Year Ended December 31, 2000
Prior to the adoption of SFAS 145[1] or EITF 03-06	$ 2.64
After the adoption of SFAS 145 but prior to the adoption of EITF 03-06	$ 2.20
After the adoption of both SFAS 145 and EITF 03-06	$ 2.13

(1) SFAS 145 "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections."

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory" (a current asset), at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is now reflected as a separate line item within other assets on the consolidated balance sheet.

This change in accounting principle was effective January 1, 2004 and is reflected in our consolidated statement of operations for the year ended December 31, 2004 and our consolidated balance sheet as of December 31, 2004. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The pro forma impact for the periods ended December 31, 2003 and 2002 is detailed below:

	Reported Year Ended December 31,		Impact of Change in Accounting Principle Year Ended December 31,		Pro Forma Year Ended December 31,	
	2003	2002	2003	2002	2003	2002
	(in millions, except per unit amounts)					
Net income	$ 59.5	$ 65.3	$ 2.0	$ (0.1)	$ 61.5	$ 65.2
Basic income per limited partner unit	$ 1.01	$ 1.34	$ 0.04	$ —	$ 1.05	$ 1.34
Diluted income per limited partner unit	$ 1.00	$ 1.34	$ 0.04	$ —	$ 1.04	$ 1.34

In conjunction with this change in accounting principle, we have classified cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification of cash flows from operating activities. Accordingly, our statement of cash flows for the years ended December 31, 2003 and 2002 has been revised to reclassify the cash paid for linefill in assets owned from operating activities to investing activities. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 increased to $115.3 million from $68.5 million and to $185.0 million from $173.9 million, respectively. Net cash used in investing activities for the years ended December 31, 2003 and 2002 increased to $272.1 million from $225.3 million and $374.8 million from $363.8 million, respectively.

Results of Operations

Analysis of Operating Segments

Our operations consist of two operating segments: (i) Pipeline Operations and (ii) GMT&S Operations. Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. 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 results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs and (iii) segment general and administrative ("G&A") expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our "available cash" (as defined in our partnership agreement) to our unitholders. Therefore, we look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which keep the actual value of our principal fixed assets from declining. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. See Note 14 "Operating Segments" in the "Notes to the Consolidated Financial Statements" for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle. The following table reflects our results of operations and maintenance capital for each segment.

	Pipeline Operations		GMT&S Operations	
	(in millions)			
Year Ended December 31, 2004[1]				
Revenues	$	874.9	$	20,223.5
Purchases		(554.6)		(19,992.8)
Field operating costs (excluding LTIP charge)		(121.1)		(97.5)
LTIP charge—operations		(0.1)		(0.8)
Segment G&A expenses (excluding LTIP charge)[2]		(38.1)		(37.7)
LTIP charge—general and administrative		(3.8)		(3.2)
Segment profit	$	157.2	$	91.5
Noncash SFAS 133 impact[3]	$	—	$	1.0
Maintenance capital	$	8.3	$	3.0
Year Ended December 31, 2003[1]				
Revenues	$	658.6	$	11,985.6
Purchases		(487.1)		(11,799.8)
Field operating costs (excluding LTIP charge)		(60.9)		(73.3)
LTIP charge—operations		(1.5)		(4.3)
Segment G&A expenses (excluding LTIP charge)[2]		(18.3)		(31.6)
LTIP charge—general and administrative		(9.5)		(13.5)
Segment profit	$	81.3	$	63.1
Noncash SFAS 133 impact[3]	$	—	$	0.4
Maintenance capital	$	6.4	$	1.2
Year Ended December 31, 2002[1]				
Revenues	$	486.2	$	7,921.8
Purchases		(362.2)		(7,765.1)
Field operating costs		(40.1)		(66.3)
Segment G&A expenses[2]		(13.2)		(31.5)
Segment profit	$	70.7	$	58.9
Noncash SFAS 133 impact[3]	$	—	$	0.3
Maintenance capital	$	3.4	$	2.6

(1) Revenues and purchases include intersegment amounts.

(2) Segment 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. The proportional allocations by segment require judgement by management and will continue to be based on the business activities that exist during each period.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

Pipeline Operations

As of December 31, 2004, we owned approximately 15,000 miles (of which approximately 13,000 miles are included in our pipeline segment) of active 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 and third party leases of pipeline capacity (collectively referred to as "tariff activities"), as well as barrel exchanges and buy/sell arrangements (collectively referred to as "pipeline margin activities"). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit 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 field costs of operating the pipeline. Segment profit 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,		
	2004	2003	2002
		(in millions)	
Operating Results[(1)]			
Revenues			
Tariff activities	$ 299.7	$ 153.3	$ 103.7
Pipeline margin activities	575.2	505.3	382.5
Total pipeline operations revenues	874.9	658.6	486.2
Costs and Expenses			
Pipeline margin activities purchases	(554.6)	(487.1)	(362.2)
Field operating costs (excluding LTIP charge)	(121.1)	(60.9)	(40.1)
LTIP charge—operations	(0.1)	(1.4)	—
Segment G&A expenses (excluding LTIP charge)[(2)]	(38.1)	(18.3)	(13.2)
LTIP charge—general and administrative	(3.8)	(9.6)	—
Segment profit	$ 157.2	$ 81.3	$ 70.7
Maintenance capital	$ 8.3	$ 6.4	$ 3.4
Average Daily Volumes (thousands of barrels per day)[(3)]			
Tariff activities			
All American	54	59	65
Basin	265	263	93
Link acquisition	283	N/A	N/A
Capline	123	N/A	N/A
Other domestic	424	299	219
Canada	263	203	187
Total tariff activities	1,412	824	564
Pipeline margin activities	74	78	73
Total	1,486	902	637

(1) Revenues and purchases include intersegment amounts.

(2) Segment 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. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

Revenues from both our tariff activities and our pipeline margin activities have increased over the three year period ended December 31, 2004. The increase in revenues from tariff activities in both the 2004 and 2003 periods is primarily related to increased volumes resulting from our acquisition activities as discussed further below. The increase in revenue from our pipeline margin activities was related to higher average prices for crude oil sold and transported on our SJV gathering system in each of the years compared to the year prior. The increase in 2004 was partially offset by lower buy/sell volumes (as compared to 2003), while the 2003 period benefitted from higher buy/sell volumes (as compared to 2002). Because the barrels that we buy and sell are generally indexed to the same pricing indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales.

Our buy/sell arrangements in our pipeline segment consisted of the following:

	Year Ended December 31,		
	2004	2003	2002
Barrels per day	12,000	17,000	10,000
Revenues (in millions)	$ 149.8	$ 166.2	$ 95.8
Purchases (in millions)	(142.5)	(159.2)	(87.6)
Margin (in millions)	$ 7.3	$ 7.0	$ 8.2

Increases in segment profit, our primary measure of segment performance, were driven by the following:

- Increased volumes and related tariff revenues—The increase in volumes and related tariff revenues in 2004 versus 2003 is primarily related to the Link acquisition, the Capline acquisition and other acquisitions completed during 2004 and late 2003. Similar increases in 2003 compared to 2002 are related to the acquisitions made in 2003, as well as the inclusion of the assets acquired in 2002 for a full year as compared to only a portion of 2002.

- Higher realized prices on our loss allowance oil—Higher crude oil prices during 2004 as compared to 2003 (the NYMEX average for 2004 was $41.29 per barrel versus $31.08 per barrel in 2003) have resulted in increased revenues related to loss allowance oil.

- Increased field operating costs—Our continued growth, primarily from the Link acquisition and other acquisitions completed during 2004 and late 2003 is the principal driver of the increase in field operating costs for 2004. The increased costs are primarily in payroll and benefits and utilities. The 2004 results also include a $1.7 million charge for a pipeline release of oil. In addition, costs related to pipeline and storage regulation have increased by approximately $2 million in 2004. The increase in field operating costs in 2003 as compared to 2002 was predominantly related to growth from acquisitions and higher utility costs. The 2003 period also includes a $1.4 million LTIP charge and a $1.0 million charge for a release of oil from a pipeline.

- Increased segment G&A expenses—The increase in segment G&A expenses in 2004 is primarily related to the Link acquisition coupled with the increase in the percentage of indirect costs allocated to the pipeline operations segment in the 2004 period as our pipeline operations have grown. G&A costs have also increased because of increased headcount from our continued growth and higher costs related to compliance activities attributable to Sarbanes-Oxley section 404 compliance. Costs related to section 404 compliance were $2.6 million in 2004. These items were partially offset by the inclusion of an LTIP charge of approximately $9.6 million in the 2003 period compared to $3.8 million in the 2004 period. The increase in 2003 as compared to 2002 is primarily related to the LTIP charge mentioned above, an overall increase in costs from our continued growth from acquisitions and increased indirect costs allocated to the pipeline operations segment as operations grew.

As discussed above, the increase in pipeline operations segment profit is largely related to our acquisition activities. We have completed a number of acquisitions during 2004 and 2003 that have impacted our results of operations. The following presentation summarizes the revenue and volume impact of recent acquisitions.

	Year Ended December 31,					
	2004		2003		2002	
	Revenues	Volumes	Revenues	Volumes	Revenues	Volumes
	(volumes in thousands of barrels per day and revenues in millions)					
Tariff activities[1][2]						
2004 acquisitions	$ 115.6	525	$ N/A	N/A	$ N/A	N/A
2003 acquisitions	39.7	170	14.8	82	N/A	N/A
2002 acquisitions	54.6	327	54.2	344	23.1	171
All other pipeline systems	89.8	390	84.3	398	80.6	393
Total tariff activities	$ 299.7	1,412	$ 153.3	824	$ 103.7	564

(1) Revenues include intersegment amounts.

(2) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

The increase in 2004 is predominately related to (i) the inclusion of an average of 283,000 barrels per day and $79.3 million of revenues from the pipelines acquired in the Link acquisition, (ii) the inclusion of an average of approximately 123,000 barrels per day and $25.9 million of revenues from the Capline pipeline system and (iii) 119,000 barrels per day and $10.4 million of revenues from other 2004 acquisitions. Additionally, volumes and revenues have increased as a result of the inclusion for the full year of 2004 of several pipeline systems acquired during 2003 as compared to only a portion of the year in 2003 (See "Acquisitions"), coupled with higher realized prices on our loss allowance oil. Revenues from all other pipeline systems increased in the 2004 period, primarily related to slightly higher volumes on various systems. The appreciation of Canadian currency also favorably impacted revenues. The Canadian dollar to U.S. dollar exchange rate appreciated to an average of 1.30 to 1 for the year ended December 31, 2004, compared to an average of 1.40 to 1 for the year ended December 31, 2003.

The increase in 2003 relates to various acquisitions completed in 2003 along with the inclusion of assets acquired in 2002 for an entire year compared to only a portion of 2002.

Maintenance Capital

For the periods ended December 31, 2004, 2003 and 2002, maintenance capital expenditures were approximately $8.3 million, $6.4 million and $3.4 million, respectively for our pipeline operations segment. The increase in 2004 is because of the growth of our business, primarily related to the Link acquisition. The increase in 2003 is related to our continued growth, primarily through acquisitions.

Gathering, Marketing, Terminalling and Storage Operations

As of December 31, 2004, we owned approximately 37 million barrels of active 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." Approximately 13.6 million barrels of our 37 million barrels of tankage is used primarily in our GMT&S Operations segment and the balance is used in our Pipeline Operations segment. On a stand-alone basis, segment profit from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities. In a contango market (when oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (when oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow. We believe that this combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flows.

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. For example, our revenues increased approximately 69% in 2004 compared to 2003, while our segment profit increased approximately 45% in the same period.

Revenues from our GMT&S operations were approximately $20.2 billion, $12.0 billion and $7.9 billion for the years ended December 31, 2004, 2003 and 2002, respectively. Revenues and costs related to purchases for the 2004 period were impacted by higher average prices and higher volumes as compared to the 2003 period. Approximately 60% of the increase in revenues resulted from higher average prices in the 2004 period and the remainder was attributable to increased sales volumes. The average NYMEX price for crude oil was $41.29 per barrel and $31.08 per barrel for the years ended December 31, 2004 and 2003, respectively. The increase in revenues and costs related to purchases in 2003 was related to higher average prices and higher volumes in 2003 as compared to 2002. The average NYMEX price for crude oil was $26.10 per barrel in 2002.

Our buy/sell arrangements in our GMT&S segment consisted of the following:

	Year Ended December 31,		
	2004	2003	2002
Barrels per day[(1)]	790,000	545,000	460,000
Revenues (in millions)[(1)]	$ 11,247.0	$ 6,124.9	$ 4,140.8
Purchases (in millions)[(1)]	(11,137.7)	(5,967.2)	(4,026.2)
Margin (in millions)	$ 109.3	$ 157.7	$ 114.6

(1) Include certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances.

Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes. Although we believe that the combination of our lease gathering business and our storage assets provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period. In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit, (ii) crude oil lease gathered volumes and LPG sales volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage Operations segment for the periods indicated:

	December 31,		
	2004	2003	2002
	(in millions, except per barrel amounts)		
Operating Results[(1)]			
Revenues	$ 20,223.5	$ 11,985.6	$ 7,921.8
Purchases and related costs	(19,992.8)	(11,799.8)	(7,765.1)
Field operating costs (excluding LTIP charge)	(97.5)	(73.3)	(66.3)
LTIP charge—operations	(0.8)	(4.3)	—
Segment G&A expenses (excluding LTIP charge)[(2)]	(37.7)	(31.6)	(31.5)
LTIP charge—general and administrative	(3.2)	(13.5)	—
Segment profit	$ 91.5	$ 63.1	$ 58.9
Noncash SFAS 133 impact[(3)]	$ 1.0	$ 0.4	$ 0.3
Maintenance capital	$ 3.0	$ 1.2	$ 2.6
Segment profit per barrel[(4)]	$ 0.39	$ 0.36	$ 0.36
Average Daily Volumes (thousands of barrels per day)[(5)]			
Crude oil lease gathered	589	437	410
Crude oil bulk purchases	148	90	68
Total	737	527	478
LPG sales	48	38	35

(1) Revenue and purchases include intersegment amounts.

(2) Segment 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. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(4) Calculated based on crude oil lease gathered barrels and LPG sales barrels.

(5) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

Increases in segment profit, our primary measure of segment performance, were driven by the following:

- Increased crude oil lease gathered volumes and LPG sales volumes—The crude oil volumes gathered from producers, using our assets or third-party assets, have increased by approximately 35% in 2004. The increase is primarily related to the Link acquisition, which has offset natural production declines. In addition, we marketed 48,000 barrels per day of LPG during 2004 compared to 38,000 barrels per day in 2003.

- Favorable market conditions—During 2004, market conditions were favorable as the crude oil market experienced significant volatility and the market shifted between backwardation and contango multiple times during the year. Additionally, price differentials between grades of crude oil were wider than normal, enhancing results. The NYMEX benchmark price of crude ranged from $32.20 to $55.65 during the period. This volatile market allowed us to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets at different times during the period. The market conditions in 2003 were also favorable as there was relatively high volatility and strong backwardation throughout the period. During 2003, the NYMEX benchmark price of crude ranged from $25.04 to $39.99 per barrel. Additionally, in the first quarter of 2003, cold weather throughout the U.S. and Canada led to increased LPG sales and higher margins.

- Change in impact from the SFAS 133 mark-to-market adjustment—The 2004 period included a non-cash gain of approximately $1.0 million resulting from the mark-to-market of open derivative instruments pursuant to SFAS 133, while the 2003 and 2002 periods included non-cash gains of approximately $0.4 million and $0.3 million, respectively.

- Impact of change in Canadian dollar to U.S. dollar exchange rate—The 2004 period includes a foreign exchange gain of $5.0 million. The gain is related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on a net U.S. dollar denominated liability of our Canadian subsidiary whose functional currency is the Canadian dollar. This is primarily attributable to our LPG business, a substantial amount of which is transacted in US Dollars.

- Lower-of-cost-or-market inventory adjustment—The 2004 period included a charge of approximately $2.0 million related to a valuation adjustment on our LPG inventory. This charge is linked to the foreign exchange gain mentioned above, and is effectively a partial reversal of that gain.

- Increased tankage available to our gathering and marketing business—As a result of various acquisitions and expansion at our Cushing Terminal, the average amount of tankage available increased to 12.7 million barrels in 2004 from 11.0 million barrels in 2003 and 10 million barrels in 2002.

- Increased field operating costs—Our continued growth, primarily from the Link acquisition is the primary driver of the increase in field operating costs for 2004 as compared to 2003. This increase was partially offset by the $4.3 million charge related to our 1998 LTIP in the 2003 period compared to $0.8 million in 2004. Field operating costs increased in 2003 as compared to 2002 primarily because of the 1998 LTIP charge mentioned above. The remaining increase was partially related to our growth in 2003, primarily related to acquisitions, coupled with increased regulatory compliance activities and higher fuel costs.

- Increased segment G&A expenses—G&A increased in 2004, primarily related to an increase in employees resulting from continued growth and higher costs related to compliance activities attributable to Sarbanes-Oxley section 404 compliance partially offset by a decrease in the percentage of indirect costs allocated to the GMT&S operations segment as the growth in our pipeline operations segment has outpaced growth in our GMT&S operations segment. Costs related to section 404 compliance were $1.9 million in 2004. The increase is partially offset by the $13.5 million charge related to our LTIP in 2003 compared to $3.2 million in 2004. The increase in G&A in 2003 as compared to 2002 is primarily related to the 1998 LTIP charge mentioned above, partially offset by the decrease in indirect costs allocated to the GMT&S segment from period to period as our Pipeline Operations segment has grown.

The impact of the items discussed above resulted in segment profit per barrel (calculated based on our lease gathered crude oil and LPG barrels) of $0.39 per barrel for 2004, compared to $0.36 for both 2003 and 2002.

Maintenance capital

For the periods ended December 31, 2004, 2003 and 2002, maintenance capital expenditures were approximately $3.0 million, $1.2 million and $2.6 million, respectively for our gathering, marketing, terminalling and storage operations segment. The increase in 2004 as compared to 2003 is primarily related to the Link acquisition. The decrease in 2003 as compared to 2002 was primarily because of a reduction in costs associated with information systems and the replacement of a portion of our fleet in 2002.

Other Income and Expenses

Unallocated G&A Expenses

Segment G&A expenses include the costs directly associated with the segments, as well as a portion of corporate overhead costs considered allocable. Total G&A expenses were $82.8 million, $73.0 million and $45.7 million for the years ended December 31, 2004, 2003 and 2002, respectively. We have included in the above segment discussion the G&A expenses for each of these years that were attributable to our segments either directly or by allocation. During 2002, we were unsuccessful in our pursuit of several sizable acquisition opportunities determined by auction and one negotiated transaction that had advanced nearly to the execution stage when it was abruptly terminated by the seller. As a result, our 2002 results reflect a $1.0 million charge to G&A expenses associated with the third-party costs of these unsuccessful transactions. This charge was not allocated to the segments.

Depreciation and Amortization

Depreciation and amortization expense was $67.2 million for the year ended December 31, 2004, compared to $46.8 million and $34.1 million for the years ended December 31, 2003 and 2002, respectively. The increase in 2004 relates primarily to the assets from our 2004 acquisitions and our various 2003 acquisitions being included for the full year versus only a part of the year in 2003. In addition, 2004 includes approximately $4.2 million of depreciation of trucks and trailers under capital leases. Amortization of debt issue costs was $2.5 million in 2004, compared to $3.8 million in 2003.

The increase in 2003 over 2002 relates primarily to the inclusion of the assets from the Shell acquisition for the entire year as compared to a portion of 2002. Additionally, several acquisitions were completed during the year along with various capital projects. Amortization of debt issue costs was flat between the two years.

Interest Expense

Interest expense was $46.7 million for the year ended December 31, 2004, compared to $35.2 million and $29.1 million for the years ended December 31, 2003 and 2002, respectively. In 2004, our average debt balance was $859.5 million. This balance consisted of fixed rate senior notes averaging $585.8 million and borrowings under our revolving credit facilities averaging $273.7 million. During the 2003 period, our average debt balance was approximately $525.5 million and consisted of fixed rate senior notes averaging $214.4 million and borrowings under our revolving credit facilities averaging $311.1 million. The higher average debt balance in 2004 was primarily related to the portion of our acquisitions that were not refinanced with equity. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity.

During the third quarter of 2004, we issued $175 million of five year senior unsecured notes and $175 million of 12 year senior unsecured notes. These issuances resulted in an increase in the average amount of longer term and higher cost fixed rate debt outstanding in 2004 to approximately 68% as compared to approximately 41% in 2003. During 2004 and 2003, the average three-month LIBOR rate was 1.6% and 1.2%, respectively.

The higher average debt balance in 2004 resulted in additional interest expense of approximately $16.8 million, while at the same time our commitment and other fees decreased by approximately $0.4 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.0% for 2004 compared to 6.0% for 2003. The lower weighted average rate decreased interest expense by approximately $4.9 million in 2004 compared to 2003.

The increase in 2003 compared to 2002 was primarily related to an increase in the average debt balance during the 2003 period to approximately $525.5 million from approximately $444.6 million in the 2002 period, which resulted in additional interest expense of approximately $5.0 million. The higher average debt balance was primarily due to the portion of the Shell acquisition that was not financed with equity. This debt was outstanding for all of 2003 versus only a portion of 2002. Also, increased commitment and other fees coupled with lower capitalized interest resulted in approximately $2.2 million of the increase in the 2003 period. Our weighted average interest rate decreased slightly during 2003 to 6.0% versus 6.2% in 2002, which decreased our interest expense by approximately $1.1 million. Although the change in our weighted average interest rate was nominal, the change was the net result of various factors that included an increase in the amount of fixed rate debt with longer maturities, long-term interest rate hedges and declining short-term interest rates. In mid-September 2002, we issued $200 million of ten-year bonds bearing a fixed interest rate of 7.75%. In the fourth quarter of 2002 and the first quarter of 2003, we entered into hedging arrangements to lock in interest rates on approximately $50 million of its floating rate debt. In addition, the average three-month LIBOR rate declined from approximately 1.8% during 2002 to approximately 1.2% during 2003. The net impact of these factors, increased commitment fees and changes in average debt balances decreased the average interest rate by 0.2%.

Other

During the third quarter of 2004, we completed (i) the issuance of 4,968,000 common units and (ii) the issuance of an aggregate of $350 million of senior unsecured notes. We used the proceeds from these issuances to, among other things, repay amounts outstanding under our revolving credit facilities, including all amounts outstanding under the $200 million, 364-day facility we used to fund the Link acquisition. The repayment and termination of this facility resulted in a non-cash charge of approximately $0.7 million associated with the write-off of unamortized debt issue costs. Additionally, during the fourth quarter of 2004, we recognized an impairment charge of approximately $2.0 million associated with taking our pipeline system in the Illinois Basin out of service. The impairment represents the remaining net book value of the idled pipeline system. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks. As a result, we were able to maintain most of our margins.

During the fourth quarter of 2003 we completed the refinancing of our bank credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted facility for the purchase of hedged crude oil (See "—Liquidity and Capital Resources—Credit Facilities and Long-term Debt"). In addition, during the third quarter of 2003 we made a $34 million prepayment on our Senior secured term B loan in anticipation of the refinancing. The completion of these transactions resulted in a non-cash charge of approximately $3.3 million associated with the write-off of unamortized debt issue costs.

Outlook

This section identifies certain matters of risk and uncertainty that may affect our financial performance and results of operations in the future.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of transportation, gathering, terminalling or storage assets and related businesses. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations. In an effort to prudently and economically leverage our asset base, knowledge base and skill sets, management has also expanded its efforts to encompass businesses that are closely related to, or significantly intertwined with, the crude oil business. We can give 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.

OCS Production. In October 2004, Plains Exploration and Production ("PXP") announced that it had successfully completed an initial development well into the Rocky Point field, which is accessible from the Point Arguello platforms and that drilling operations are underway on a second development well. We can give no assurances, however, that our volumes transported would increase as a result of this drilling activity.

Pipeline Integrity and Storage Tank Testing Compliance. Although we believe our short-term estimates of costs under the pipeline integrity management rules and API 653 (and similar Canadian regulations) are reasonable, a high degree of uncertainty exists with respect to estimating such costs, as we continue to test existing assets and as we acquire new assets.

Sarbanes Oxley Act and Related Legislation. Several regulatory and legislative initiatives were introduced in 2002 and 2003 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 recurrence of similar events. We believe implementation of reforms in connection with these initiatives have added to the costs of doing business for most publicly traded entities, including us as a partnership. These costs will have an adverse impact on future income and cash flow.

Longer Term Outlook. Our longer-term outlook, spanning a period of five or more years, is influenced by many factors affecting the North American crude oil sector. Some of the more significant trends and factors include:

1. Continued overall depletion of U.S. crude oil production.

2. The continuing convergence of worldwide crude oil supply and demand trends.

3. Aggressive practices in the U.S. to maintain working crude oil inventory levels below historical levels despite rising demand in North America.

4. Industry compliance with the Department of Transportation's adoption of the American Petroleum Institute's standard 653 for testing and maintenance of storage tanks, which will require significant investments to maintain existing crude oil storage capacity or, alternatively, will result in a reduction of existing storage capacity by 2009.

5. The expectation of increased crude oil production from certain North American regions (primarily Canadian oil sands and deepwater Gulf of Mexico sources) that will, of economic necessity, compete for U.S. markets currently being supplied by non-North American foreign crude imports.

We believe the collective impact of these trends, factors and developments, many of which are beyond our control, will result in an increasingly volatile crude oil market that is subject to more frequent short-term swings in market prices and grade differentials and shifts in market structure. In an environment of reduced inventories and tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments, and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2004, we had a working capital deficit of approximately $12.5 million, approximately

$420.2 million of availability under our committed revolving credit facilities and $344.6 million of unused capacity under our uncommitted hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants. In January 2005, we had additional net borrowings under our uncommitted hedged inventory facility of approximately $236.8 million. The proceeds were used to pay for crude oil stored at December 31, 2004.

Capital Resources

We periodically access the capital markets for both equity and debt financing. In April 2004, we completed the private placement of 3,245,700 units of Class C common units to a group of institutional investors comprised of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital Advisors for $30.81 per unit. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, was approximately $101 million. In the third quarter of 2004, we completed a public offering of 4,968,000 common units for $33.25 per unit. The offering resulted in gross proceeds of approximately $165.2 million from the sale of units and approximately $3.4 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $7.7 million. Net proceeds of $160.9 million were used to permanently reduce outstanding borrowings under the $200 million, 364-day credit facility.

In August 2004, we completed the sale of $350 million of senior notes. We used the net proceeds, after deducting initial purchaser discounts and offering costs, of approximately $345 million to repay amounts outstanding under our credit facilities, including the remaining balance under the $200 million, 364-day facility we used to fund the Link acquisition, and for general partnership purposes. In connection with this repayment, we terminated the facility. Subsequent to the notes offering, we also terminated our $125 million, 364-day facility, which was scheduled to expire in November 2004.

Capital Expenditures

We have made and will continue to make capital expenditures for acquisitions, expansion capital 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 invest approximately $100 million on expansion capital projects during 2005. Our 2005 expansion capital projects include the following notable projects with the estimated cost for the entire year.

	Estimated to be Incurred in 2005 (in millions)
Capital projects and upgrades associated with the Link acquisition	$ 18.0
Trenton pipeline expansion	16.0
Cushing Phase V expansion	13.0
Cal Ven fractionator	16.0
Capital projects and upgrades associated with the Shell South Louisiana Assets acquisition	8.0
Other	29.0
	$ 100.0

In addition, we expect to invest approximately $19.0 million on maintenance capital projects during 2005.

We believe that we have sufficient liquid assets, cash flow 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 an adverse effect on our borrowing capacity.

Cash Flows

Cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows:

	Year Ended December 31,		
	2004	2003	2002
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 104.0	$ 115.3	$ 185.0
Investing activities	(651.2)	(272.1)	(374.9)
Financing activities	554.5	157.2	189.5

Operating Activities. The primary drivers of our cash flow from operations are (i) the collection of amounts related to the sale of crude oil and LPG and the transportation of crude oil for a fee and (ii) the payment of amounts related to the purchase of crude oil and LPG and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except in the months that we store inventory because of contango market conditions or in months that we increase linefill. The storage of crude oil in periods of a contango market can have a material impact on our cash flows from operating activities for the period we pay for and store the crude oil and the subsequent period that we receive proceeds from the sale of the crude oil. When we store the crude oil, we borrow on our credit facilities to pay for the crude oil so the impact on operating cash flow is negative. Conversely, cash flow from operations increases in the period we collect the cash from the sale of the stored crude oil. In addition, our cash flow from operating activities is also impacted by the level of LPG inventory stored at period end.

Cash flow from operations was $104.0 million in 2004 and reflects cash generated by our recurring operations that was offset negatively by several factors totaling approximately $100 million. The primary item was a net increase in hedged crude oil and LPG inventory and linefill in third party assets that was financed with borrowings under our credit facilities (approximately $75 million net). Cash flows from operations were also negatively impacted by a decrease of approximately $20 million in prepayments received from counter parties to mitigate credit risk.

Our positive cash flow from operations for 2003 resulted from cash generated by our recurring operations. In addition, cash flow from operating activities was positively impacted by approximately $74 million related to proceeds received in 2003 from the sale of 2002 hedged crude oil inventory and negatively impacted by approximately $100 million related to inventory stored at the end of 2003. The proceeds from the sale of the 2003 stored crude oil were received in the first quarter of 2004. In 2003, we also received approximately $23 million of additional prepayments over the 2002 balance from counter parties to mitigate our credit risk, and paid approximately $6.2 million to terminate an interest rate hedge in conjunction with a change in our capital structure.

Our positive cash flow from operations for 2002 resulted from cash generated by our recurring operations. In addition, we received approximately $93 million of proceeds during 2002 associated with crude oil hedged and stored during 2001. This was partially offset by the payment of approximately $74 million for crude oil purchased and stored during 2002 but for which receipt of the proceeds occurred during 2003. In addition, our 2002 cash flow from operating activities was positively impacted by the collection of approximately $21 million of prepayments from counter parties to mitigate our credit risks and the collection of approximately $9.1 million of amounts that had been outstanding primarily since 1999 and 2000.

Investing Activities. Net cash used in investing activities in 2004, 2003 and 2002 consisted predominantly of cash paid for acquisitions. Net cash used in 2004 was approximately $651 million and was comprised primarily of cash paid for acquisitions of $535 million, which included (i) approximately $294 million for the Link acquisition, (ii) approximately $143 million for the Capline/Capwood acquisition (a deposit of $15.8 million was paid during 2003), (iii) approximately $47 million for the Schafferstown Propane Storage Facility (including approximately $14.2 million of working inventory) and (iv) approximately $51 million related to various other acquisitions. Investing activities for 2004 also included over $115 million of property and equipment construction and capitalized maintenance projects, which includes approximately $34 million related to the Cushing to Broome pipeline construction project.

Net cash used in investing activities 2003 was $272.1 million and was comprised of (i) an aggregate $152.6 million paid primarily for ten acquisitions completed during 2003, (ii) a $15.8 million deposit paid on the Capline acquisition; see "—Acquisitions", (iii) proceeds of approximately $8.5 million from sales of assets, and (iv) $65.4 million paid for additions to property and equipment, including $19.2 million related to the construction of crude oil gathering and transmission lines in West Texas, and (v) crude oil linefill purchases of approximately $47 million, primarily attributable to increased linefill requirements related to 2003 and 2002 acquisitions. Net cash used in 2002 was $374.9 million and was comprised of (i) an aggregate $324.6 million paid for three acquisitions completed during 2002; see "—Acquisitions", and (ii) $40.6 million paid for additions to property and equipment, primarily related to our Cushing expansion and the construction of the Marshall terminal in Canada, and (iii) crude oil linefill purchases of approximately $11 million.

Financing Activities. Cash provided by financing activities in 2004 consisted primarily of $348.1 million of net proceeds from the issuance of senior notes and $262.1 million of net proceeds from the issuance of common units, used primarily to fund acquisitions and pay down outstanding balances on our revolving credit facilities. Net borrowings under our short-term and long-term revolving credit facilities were $107.7 million. In addition, $158.4 million of distributions were paid to our unitholders and general partner.

Cash provided by financing activities in 2003 consisted primarily of $499.7 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 our revolving credit facilities and senior term loans. Net repayments of our short-term and long-term revolving credit facilities and related senior term loans were $215.4 million. In addition, $121.8 million of distributions were paid to our unitholders and general partner. 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 our unitholders and general partner during the year ended December 31, 2002.

Credit Facilities and Long-term Debt

During August 2004, we completed the sale of $175 million of 4.75% senior notes due 2009 and $175 million of 5.88% senior notes due 2016. The 4.75% notes were sold at 99.551% of face value and the 5.88% notes were sold at 99.345% of face value. We used the net proceeds, after deducting initial purchaser discounts and offering costs, of approximately $345 million to repay amounts outstanding under our credit facilities, including the remaining balance under the $200 million, 364-day facility funded in connection with the Link acquisition, and for general partnership purposes. In connection with this repayment, we terminated the facility. Subsequent to the notes offering, we also terminated our $125 million, 364-day facility that was scheduled to expire in November 2004.

In November 2004, we entered into a new $750 million, five-year senior unsecured credit facility, which contains a sub-facility for Canadian borrowings of up to $300 million. The new credit facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facilities. This facility can be expanded to $1 billion. As of December 31, 2004, we had approximately $231.8 million outstanding under this credit facility, as well as $98.0 million in letters of credit outstanding, resulting in unused capacity under the facility of approximately $420.2 million.

Also in the fourth quarter of 2004, we amended and renewed our secured hedged inventory facility; increasing the facility to $425 million, with the ability to further increase the facility in the future by an incremental $75 million. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are secured by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. This facility expires in November 2005. As of December 31, 2004, we had approximately $80.4 million outstanding and no letters of credit issued under our hedged crude oil inventory facility resulting in unused uncommitted capacity under this facility of approximately $344.6 million.

Our credit agreements and the indentures governing our senior notes contain cross default provisions. Our credit agreements 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 if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions;
- sell substantially all of our assets or enter into a merger or consolidation.

Our credit facility treats a change of control as an event of default and also requires us to maintain:

- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt coverage ratio which will not be greater than 4.75 to 1.0 on all outstanding debt and 5.25 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures.

Contingencies

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. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 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 received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, asserted breach of fiduciary duty and breach of contract claims against us, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. The complaint sought to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. This lawsuit has been settled in principle. The court has approved the settlement and, assuming no appeals are filed, the settlement will become final in March 2005.

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 barrels were recovered from the two respective sites. The unrecovered oil has been or will be removed or otherwise addressed by PAA in the course of site remediation. Aggregate costs associated with each release, including estimated remediation costs, are estimated at approximately $1.7 million and $1.4 million, respectively. We continue to work with the appropriate state and federal environmental authorities in responding to the releases and no enforcement proceedings have been instituted by any governmental authority at this time.

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

Environmental. We may experience future releases of crude oil into the environment from our pipeline, gathering 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. At December 31, 2004, our reserve for environmental liabilities totaled approximately $19.8 million. Approximately $12.7 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

Other. A pipeline, terminal or other facility 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 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. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe 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, or that we have established adequate reserves to the extent that such risks are not insured.

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The table below includes purchase obligations related to these activities. Where applicable the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to credit worthy entities.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2004.

	2005	2006	2007	2008	2009	Thereafter
			(in millions)			
Long-term debt and interest payments[(1)]	$ 49.7	$ 49.7	$ 49.7	$ 49.7	$ 368.0	$ 799.7
Leases[(2)]	17.8	14.0	10.9	6.3	5.2	13.7
Capital expenditure obligations	20.6	—	—	—	—	—
Other long-term liabilities[(3)]	2.8	4.9	3.5	1.6	1.1	3.0
Subtotal	90.9	68.6	64.1	57.6	374.3	816.4
Crude oil and LPG purchases[(4)]	1,265.7	20.0	2.0	2.0	1.0	—
Total	$ 1,356.6	$ 88.6	$ 66.1	$ 59.6	$ 375.3	$ 816.4

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. While there is an outstanding balance on our revolving credit facility at December 31, 2004 (this amount is included in the amounts above), we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for office rent and trucks used in our gathering activities.

(3) Excludes approximately $10.6 million non-current liability related to SFAS 133 which are included in crude oil and LPG purchases.

(4) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers 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, 2004, we had outstanding letters of credit of approximately $98.0 million.

Distributions. We plan to 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. On February 14, 2005, we paid a cash distribution of $0.6125 per unit on all outstanding units. The total distribution paid was approximately $45.0 million, with approximately $41.2 million paid to our common unitholders and approximately $3.8 million paid to our general partner for its general partner ($0.8 million) and incentive distribution interests ($3.0 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. In 2004, we paid $8.3 million in incentive distributions to our general partner. See "Certain Relationships and Related Transactions—Our General Partner."

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 307 of Regulation S-K.

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 segment profit 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. We estimate that a 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline segment profit of approximately $3.2 million. In addition, any significant production disruption from the Santa Ynez field due to production problems, transportation problems or other reasons could have a material adverse effect on our business.

Our trading policies cannot eliminate all price risks. In addition, any non-compliance with our trading policies could result in significant financial losses.

Generally, it is our policy that we establish a margin for crude oil purchased 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 generally not to acquire and hold crude oil, futures contracts or derivative products for the purpose of speculating on price changes. This policy cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply of crude oil could expose us to risk of loss resulting from price changes. Moreover, we are exposed to some risks that are not hedged, including certain basis risks and price risks on certain of our inventory, such as pipeline linefill, which must be maintained in order to transport crude oil on our pipelines. In addition, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. Although this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations.

In addition, our trading operations involve the risk of non-compliance with our trading policies. For example, we discovered in November 1999 that our trading policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181.0 million. We have taken steps within our organization to enhance our processes and procedures to detect 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.

If we do not make acquisitions on economically acceptable terms our future growth may be limited.

Our ability to grow is substantially dependent on our ability to make acquisitions that result in an increase in adjusted operating surplus per unit. If we are unable to make such accretive acquisitions either because (i) we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (ii) we are unable to raise financing for such acquisitions on economically acceptable terms or (iii) we are outbid by competitors, our future growth will be limited. In particular, competition for midstream assets and businesses has intensified substantially and as a result such assets and businesses have become more costly. As a result, we may not be able to complete the number or size of acquisitions that we have targeted internally or to continue to grow as quickly as we have historically.

Our acquisition strategy requires access to new capital. Tightened capital markets or other factors which increase our cost of capital could impair our ability to grow.

Our business strategy is substantially dependent on acquiring additional assets or operations. We continuously consider and enter into discussions regarding potential acquisitions. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. Any material acquisition will require access to capital. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our ability to execute our acquisition strategy. Our ability to maintain our targeted credit profile, including maintaining our credit ratings, could impact our cost of capital as well as our ability to execute our acquisition strategy.

Our acquisition strategy involves risks that may adversely affect our business.

Any acquisition involves potential risks, including:

- performance from the acquired assets and businesses that is below the forecasts we used in evaluating the acquisition;
- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;
- customer or key employee loss from the acquired businesses; and
- the diversion of management's attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to pay distributions or meet our debt service requirements.

The nature of our assets and business could expose us to significant compliance costs and liabilities.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment, otherwise relating to protection of the environment, operational safety and related matters. Compliance with these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities, or claims for damages to property or persons resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and the issuance of injunctions that may restrict or prohibit our operations or even claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids 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 liability to private parties for personal injury or property damage.

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

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, we estimate that an average 20,000 barrel per day variance in the Basin Pipeline System within the current operating window, equivalent to an approximate 7% volume variance on that system, would change annualized segment profit by approximately $1.8 million. In addition, we estimate that an average 10,000 barrel per day variance on the Capline Pipeline System, equivalent to an approximate 7% volume variance on that system, would change annualized segment profit by approximately $1.5 million.

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 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. 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.

We face intense competition in our gathering, marketing, terminalling and storage 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. We estimate that a $0.01 variance in the average segment profit per barrel would have an approximate $2.6 million annual effect on segment profit.

The profitability of our gathering and marketing activities is generally dependent 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 15,000 barrel per day decrease in barrels gathered by us would have an approximate $3.0 million per year negative impact on segment profit. 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.

There can be no assurance that we have adequately assessed the credit worthiness of our existing or future counterparties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

In those cases in which 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 pipeline assets are subject to federal, state and provincial regulation.

Our domestic interstate common carrier pipelines are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be just and reasonable and non-discriminatory. We are also subject to the Pipeline Safety Regulations of the U.S. Department of Transportation. Our intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

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 Canadian 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.

Fluctuations in demand can negatively affect our operating results.

Fluctuations in demand for crude oil, such as caused by refinery downtime or shutdown, can have a negative effect on our operating results. Specifically, reduced demand in an area serviced by our transmission systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by our ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

The terms of our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities.

As of December 31, 2004, our total outstanding long-term debt was approximately $949 million. Various limitations in our indebtedness may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Changes in currency exchange rates could adversely affect our operating results.

Because we conduct operations in Canada, we are exposed to currency fluctuations and exchange rate risks that may adversely affect our results of operations.

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

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 our ability to make cash distributions to our unitholders or pay our debt service obligations.

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 could materially and adversely affect our ability to make cash distributions to our unitholders or 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. Imposition of such forms of taxation would reduce the cash available for distribution to unitholders and for payment of debt service obligations. 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 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 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 and sales of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. 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 segment profit we receive. Except for the controlled trading program discussed below, 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.

While we seek to maintain a position that is substantially balanced within our crude oil lease purchase and LPG activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. 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 an aggregate of 500,000 barrels of crude oil.

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 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 exception of the controlled trading 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. This accounting treatment is discussed further under Note 2 "Summary of Significant Accounting Policies" of our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2004 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	$	42.3	$	(11.8)
Swaps and options contracts		(5.1)		(5.1)
LPG:				
Swaps and option contracts		2.3		(2.7)

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 exposures to the cash market; none of these offsetting physical exposures 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. Therefore, from time to time we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. There are no interest rate hedging instruments outstanding as of December 31, 2004. 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, 2004. All of our senior notes are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance rate plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2004. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market.

	Expected Year of Maturity													
	2005		2006		2007		2008		2009		Thereafter		Total	
							(in millions)							
Liabilities:														
Short-term debt—variable rate	$	168.6	$	—	$	—	$	—	$	—	$	—	$	168.6
Average interest rate		3.4%		—		—		—		—		—		3.4
Long-term debt—variable rate	$	—	$	—	$	—	$	—	$	143.6	$	—	$	143.6
Average interest rate		—		—		—		—		3.5%		—		3.5

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.

Because a significant portion 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 and cross currency swaps. Neither the forward exchange contracts nor the cross currency swaps qualify for hedge accounting in accordance with SFAS 133.

At December 31, 2004, we had forward exchange contracts that allow us to exchange Canadian dollars for U.S. dollars, quarterly, at set exchange rates as detailed below:

	Canadian Dollars	US Dollars	Rate
	($ in millions)		
2005	$ 3.0	$ 2.3	1.33 to 1
2006	$ 2.0	$ 1.5	1.32 to 1

In addition, at December 31, 2004, we also had cross currency swap contracts for an aggregate notional principal amount of $21.0 million effectively converting this amount of our U.S. dollar denominated debt to $32.5 million of Canadian dollar debt (based on Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount reduces by $2.0 million U.S. in May 2005 and has a final maturity in May 2006 ($19.0 million U.S.). At December 31, 2004, $9.9 million of our long-term debt was denominated in Canadian dollars ($11.9 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.20 to 1). All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

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				
	2005	2006	2007	2008	Total
Forward exchange contracts	$ (0.9)	$ (0.6)	$ —	$ —	$ (1.5)
Cross currency swaps	(0.9)	(5.4)	—	—	(6.3)
Total	$ (1.8)	$ (6.0)	$ —	$ —	$ (7.8)

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

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

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

None.

Item 9A. ***Controls and Procedures***

We maintain written "disclosure controls and procedures," which we refer to as our "DCP." The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in time to allow for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of December 31, 2004, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls during preparation for our assertion on internal control over financial reporting, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. §1350 are furnished with this report as Exhibits 32.1 and 32.2.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. "Internal control over financial reporting" is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2004. See Management's Report on Internal Control Over Financial Reporting on page F-2.

Item 9B. ***Other Information***

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 (other than our Canadian personnel who are employed by PMC (Nova Scotia) Company). 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 and LPG operations, PMC (Nova Scotia) Company).

Our general partner manages our operations and activities. Unitholders are limited partners and 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 us 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, our partnership agreement defines "Board of Directors" to mean the board of directors of Plains All American GP LLC, which is comprised of eight directors elected by the members of Plains All American GP LLC, and not by the unitholders. Four directors are designated by the four owners that hold 9% or greater of the outstanding membership interests of Plains All American GP LLC, one director is the Chairman and CEO and three independent directors are elected by majority vote of the membership owners of Plains All American GP LLC. Thus, the corporate governance of Plains All American GP LLC is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement. Because we are a limited partnership, the new listing standards of the New York Stock Exchange do not require that we or our general partner have a majority of independent directors or a nominating or compensation committee of the board of directors.

Non-management directors meet in executive session in connection with each regular board meeting. Each non-management director acts as presiding director at the regularly scheduled executive sessions, rotating alphabetically by last name.

Interested parties can communicate directly with non-management directors by mail in care of Tim Moore, General Counsel and Secretary or Sharon Spurlin, Director of Internal Audit, Plains All American Pipeline, L.P., 333 Clay Street, Suite 1600, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

We have an audit committee that reviews our external financial reporting, engages our independent auditors and reviews the adequacy of our internal accounting controls. The Board of Directors has determined that (i) each member of our audit committee is "independent" under applicable New York Stock Exchange Rules and (ii) that each member of our audit committee is an "Audit Committee Financial Expert," as that term is defined in Item 401 of Regulation S-K. The members of our audit committee and other committees are indicated in the table below.

In determining the independence of the members of our audit committee, the Board of Directors considered the relationships described below:

Mr. Everardo Goyanes, the Chairman of our Audit Committee, is the Chief Executive Officer of Liberty Energy Corporation ("LEC"), a subsidiary of Liberty Mutual Insurance Company. Mr. Goyanes is an employee of Liberty Mutual Insurance Company. LEC makes investments in producing properties, from some of which Plains Marketing, L.P. buys the production. LEC does not operate the properties in which it invests. Plains Marketing pays the same amount per barrel to LEC that it pays to other interest owners in the properties. In 2004, the amount paid to LEC by Plains Marketing was approximately $1.1 million ($1.0 million net of severance taxes).

Mr. J. Taft Symonds, a member of our Audit Committee, is a director and the non-executive Chairman of the Board of Tetra Technologies, Inc. ("Tetra"). A subsidiary of Tetra owns crude oil producing properties, from some of which Plains Marketing buys the production. We paid approximately $11 million to the Tetra subsidiary in 2004. Until July 2004, Mr. Symonds was also a director of Plains Resources Inc., with whom Plains Marketing has a marketing arrangement. We paid approximately $28.3 million to Plains Resources in 2004, and recognized segment profit of approximately $0.1 million. Mr. Symonds was not and is not an officer of Tetra or Plains Resources, and does not participate in operational decision making, including decisions concerning selection of crude oil purchasers or entering into sales or marketing arrangements.

We have a compensation committee, which reviews and makes recommendations regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. We also have a governance committee that periodically reviews our governance guidelines. 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. Such a committee would consist of a minimum of two members, none of whom can be officers or employees of our general partner or directors, officers or employees of its affiliates nor owners of the general partner's interest. 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.

Our committee charters and governance guidelines, as well as our Code of Business Conduct and our Code of Ethics for Senior Financial Officers, are available on our website at www.paalp.com.

Report of the Audit Committee

The audit committee of Plains All American GP LLC oversees the Partnership's financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls.

In fulfilling its oversight responsibilities, the audit committee reviewed and discussed with management the audited financial statements contained in this Annual Report on Form 10-K.

The Partnership's independent registered public accounting firm, PricewaterhouseCoopers LLP, are responsible for expressing an opinion on the conformity of the audited financial statements with generally accepted accounting principles and opinions on management's assessment and on the effectiveness of the Partnership's internal control over financial reporting. The audit committee reviewed with PricewaterhouseCoopers LLP their judgment as to the quality, not just the acceptability, of the Partnership's accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards.

The audit committee discussed with PricewaterhouseCoopers LLP the matters required to be discussed by SAS 61 (Codification of Statement on Auditing Standards, AU § 380), as may be modified or supplemented. The committee received written disclosures and the letter from PricewaterhouseCoopers LLP required by Independence Standards Board No. 1, *Independence*

Discussions with Audit Committees, as may be modified or supplemented, and has discussed with PricewaterhouseCoopers LLP its independence from management and the Partnership.

Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2004 for filing with the SEC.

Everardo Goyanes, Chairman
Arthur L. Smith
J. Taft Symonds

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 are elected annually. 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 (as of 12/31/04)	Position with Our General Partner
Greg L. Armstrong[1]	46	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis	47	President and Chief Operating Officer
Phillip D. Kramer	48	Executive Vice President and Chief Financial Officer
George R. Coiner	54	Senior Group Vice President
W. David Duckett	49	President—PMC (Nova Scotia) Company
Mark F. Shires	47	Senior Vice President—Operations
Alfred A. Lindseth	35	Senior Vice President—Technology, Process & Risk Management
Lawrence J. Dreyfuss	50	Vice President, Associate General Counsel and Assistant Secretary; Vice President, General Counsel and Secretary of PMC (Nova Scotia) Company (the general partner of Plains Marketing Canada, L.P.)
James B. Fryfogle	53	Vice President—Lease Operations
Jim G. Hester	45	Vice President—Acquisitions
Tim Moore	47	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	47	Vice President—Engineering
John F. Russell	56	Vice President—Pipeline Operations
Al Swanson	40	Vice President and Treasurer
Tina L. Val	35	Vice President—Accounting and Chief Accounting Officer
Troy E. Valenzuela	43	Vice President—Environmental, Health and Safety
John P. vonBerg	50	Vice President—Trading
David N. Capobianco[1]	35	Director and Member of Compensation Committee
Everardo Goyanes	60	Director and Member of Audit* Committee
Gary R. Petersen[1]	58	Director and Member of Compensation* Committee
John T. Raymond[1]	34	Director
Robert V. Sinnott[1]	55	Director and Member of Compensation Committee
Arthur L. Smith	52	Director and Member of Audit and Governance* Committees
J. Taft Symonds	65	Director and Member of Governance and Audit Committees

* Indicates chairman of committee.

(1) The Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (as amended, the "LLC Agreement") specifies that the Chief Executive Officer of the general partner will be a member of the board of directors.

The LLC Agreement also provides that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Capobianco has been designated by Plains Holdings Inc., which is owned by Vulcan Energy Corporation, of which he is Chairman of the board. Mr. Petersen has been designated by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is a Managing Director. Mr. Raymond has been designated by Sable Investments, L.P. Sable Investments, L.P. is controlled by James M. Flores, a director of Vulcan Energy Corporation and also the Chairman, President and Chief Executive Officer of PXP. 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. See "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 Inc. 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. Mr. Armstrong is also a director of Varco International, Inc.

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 Group Vice President since February 2004 and as Senior Vice President from our formation to February 2004. In addition, he was Vice President of Plains Marketing & Transportation Inc., 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.

W. David Duckett has been President of PMC (Nova Scotia) Company since June 2003, and Executive Vice President of PMC (Nova Scotia) Company from July 2001 to June 2003. 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.

Mark F. Shires has served as Senior Vice President—Operations since June 2003 and as Vice President—Operations from August 1999 to June 2003. He served as Manager of Operations from April 1999 to August 1999. 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, LP from May 1998 until April 1999. He previously served as President of Plains Terminal & Transfer Corporation, from 1993 to 1996.

Alfred A. Lindseth has served as Senior Vice President—Technology, Process & Risk Management since June 2003 and as Vice President—Administration from March 2001 to June 2003. He served as Risk Manager from March 2000 to March 2001. 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.

Lawrence J. Dreyfuss has served as Vice President, Associate General Counsel and Assistant Secretary of our general partner since February 2004 and as Associate General Counsel and Assistant Secretary of our general partner from June 2001 to February 2004 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.

James B. Fryfogle has served as Vice President—Lease Operations since July 2004. Prior to joining us in January 2004, Mr. Fryfogle served as Manager of Crude Supply and Trading for Marathon Ashland Petroleum. Mr. Fryfogle had held numerous positions of increasing responsibility with Marathon Ashland Petroleum or its affiliates or predecessors since 1975.

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 energy industry experience as a petroleum geologist.

John F. Russell has served as Vice President—Pipeline Operations since July 2004. Prior to joining PAA, Mr. Russell served as Vice President of Business Development & Joint Interest for ExxonMobil Pipeline Company. Mr. Russell had held numerous positions of increasing responsibility with ExxonMobil Pipeline Company or its affiliates or predecessors since 1974.

Daniel J. Nerbonne has served as Vice President—Engineering since February 2005. Prior to joining us, Mr. Nerbonne was General Manager of Portfolio Projects for Shell Oil Products US from January 2004 to January 2005 and served in various capacities, including General Manager of Commercial and Joint Interest, with Shell Pipeline Company or its predecessors from 1998. From 1980 to 1998 Mr. Nerbonne held numerous positions of increasing responsibility in engineering, operations, and business development, including Vice President of Business Development from December 1996 to April 1998, with Texaco Trading and Transportation or its affiliates.

Al Swanson has served as Vice President and Treasurer since February 2004 and as Treasurer from May 2001 to February 2004. In addition, he held finance related 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.

Tina L. Val has served as Vice President—Accounting and Chief Accounting Officer since June 2003. She served as Controller from April 2000 until she was elected to her current position. From January 1998 to January 2000, Ms. Val served as a consultant to Conoco de Venezuela S.A. She previously served as Senior Financial Analyst for Plains Resources from October 1994 to July 1997.

Troy E. 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 us and our predecessors for the last 12 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.

John P. vonBerg has served as Vice President of Trading since May 2003 and Director of these activities since joining us in January of 2002. He was with Genesis Energy in differing capacities as a Director, Vice Chairman, President and CEO from 1996 through 2001, and from 1993 to 1996 he served as a Vice President and a Crude Oil Manager for Phibro Energy USA. Mr. VonBerg began his career with Marathon Oil Company, spending 13 years in various disciplines.

David N. Capobianco has served as a director of our general partner since July 2004. Mr. Capobianco is Chairman of the board of directors of Vulcan Energy Corporation and a Managing Director of Vulcan Capital, an affiliate of Vulcan Inc., where he has been employed since April 2003. Previously, he served as a Vice President of Greenhill Capital from July 2001 to April 2003 and a Vice President of Harvest Partners from July 1995 to January 2001.

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 LLC (an energy investment firm) 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 (a banking firm). He was a financial consultant from 1987 to 1989 and was Vice President —Finance of Forest Oil Corporation from 1983 to 1987. Mr. Goyanes received a BA in Economics from Cornell University and a Masters degree in Finance (honors) from Babson Institute.

Gary R. Petersen has served as a director since June 2001. Mr. Petersen co-founded EnCap Investments L.P. (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 Equus II Incorporated.

John T. Raymond has served as a director since June 2001. He has been a director and the Chief Executive Officer of Vulcan Energy Corporation since July 2004. Mr. Raymond has served as President and Chief Executive Officer of Plains Resources since December 2002. 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. Mr. Raymond also served as President and Chief Operating Officer of Plains Exploration and Production from December 2002 to March 2004. 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 Glacier Water Services, Inc. (a vended water company). Mr. Sinnott was previously a director of Plains Resources.

Arthur L. Smith has served as a director of our general partner or former general partner since February 1999. Mr. Smith is Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm), a position he has held since 1984. From 1976 to 1984 Mr. Smith was a securities analyst with Argus Research Corp., The First Boston Corporation and Oppenheimer & Co., Inc. Mr. Smith has prior public board experience with Pioneer Natural Resources, Cabot Oil & Gas Corporation and Evergreen Resources, Inc. Mr. Smith holds the CFA designation. He serves on the board of non-profit Dress for Success Houston and the Board of Visitors for the Duke Nicholas School of the Environment and Earth Sciences. Mr. Smith received a BA from Duke University and an MBA from NYU's Stern School of Business.

J. Taft Symonds has served as a director since June 2001. Mr. Symonds is Chairman of the Board of Symonds Trust Co. Ltd. (an investment firm) and Chairman of the Board of Tetra Technologies, Inc. (an oilfield services firm). From 1978 to 2004 he was Chairman of the Board and Chief Financial Officer of Maurice Pincoffs Company, Inc. (an international marketing firm). Mr. Symonds was previously a director of Plains Resources. Mr. Symonds has a background in both investment and commercial banking, including merchant banking in New York, London and Hong Kong with Paine Webber Jackson & Curtis, Robert Fleming Group and Banque de la Societe Financiere Europeenne. He is a director of Intercorr International and President of the Houston Arboretum and Nature Center. Mr. Symonds received a BA from Stanford University and an MBA from Harvard.

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 2004, except as follows: Mr. Valenzuela filed a late Form 4 related to the vesting of phantom units under the 1998 LTIP, Mr. VonBerg filed a one-day late Form 3, and Mr. Swanson and Paul G. Allen each timely filed a Form 5 reporting a transfer in 2004 (reportable on Form 4) of 1,109 units in connection with the vesting of an employee equity grant.

Management Team/Canadian Officers

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 (as of 12/31/04)	Position with Our General Partner/ Canadian General Partner
Management Team:		
A. Patrick Diamond	32	Manager—Special Projects
Canadian Officers:		
D. Mark Alenius	45	Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Ralph R. Cross	49	Vice President—Business Development of PMC (Nova Scotia) Company
Ronald H. Gagnon	46	Vice President—Operations of PMC (Nova Scotia) Company
M.D. (Mike) Hallahan	44	Vice President—Crude Oil of PMC (Nova Scotia) Company
Richard (Rick) Henson	50	Vice President—Corporate Services of PMC (Nova Scotia) Company
Ron F. Wunder	36	Vice President—LPG 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 an Associate from July 1997 to May 1999 and as a Financial Analyst from July 1994 to June 1997.

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.

Ronald H. Gagnon has been Vice President, Operations of PMC (Nova Scotia) Company since January 2004, Managing Director, Information and Transportation Services from June 2003 to January 2004 and Director, Information Services from July 2001 to May 2003. Mr. Gagnon was previously with CANPET Energy Group Inc. since 1987, where he served in various capacities, including Vice President, Producer Services.

M.D. (Mike) Hallahan has served as Vice President, Crude Oil of PMC (Nova Scotia) Company since February 2004 and Managing Director, Facilities from July, 2001 to February, 2004. He was previously with CANPET Energy Group Inc. where he served in various capacities since 1996, most recently General Manager, Facilities.

Richard (Rick) Henson joined PMC (Nova Scotia) Company in December 2004 as Vice President of Corporate Services. Mr. Henson was previously with Nova Chemicals Corporation, serving in various executive positions from 1999 through 2004, including Vice President, Petrochemicals and Feedstocks, and Vice President, Ethylene and Petrochemicals Business.

Ron F. Wunder has served as Vice President, LPG of PMC (Nova Scotia) Company since February 2004 and as Managing Director, Crude Oil from July 2001 to February 2004. He was previously with CANPET Energy Group Inc. since 1992, where he served in various capacities, including most recently as General Manager, Crude Oil.

Item 11. *Executive Compensation*

The following table sets forth certain compensation information for our Chief Executive Officer and the four other most highly compensated executive officers in 2004 (the "Named Executive Officers"). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation. The Named Executive Officers have also received certain equity-based awards from our general partner, which awards (other than awards under the Long-Term Incentive Plans) are not subject to reimbursement by us. See "—Long-Term Incentive Plan" and "Certain Relationships and Related Transactions—Transactions with Related Parties."

		Annual Compensation		Long-Term Compensation	
Name and Principal Position	**Year**	**Salary**	**Bonus**	**LTIP Payout**	**All Other Compensation**
Greg L. Armstrong	2004	$330,000	$1,800,000	$1,692,600	$13,930(1)
Chairman and CEO	2003	330,000	1,000,000	—	12,930
	2002	330,000	600,000	—	11,930
Harry N. Pefanis	2004	$235,000	$1,500,000	$1,674,600	$13,875(1)
President and COO	2003	235,000	800,000	452,400	12,875
	2002	235,000	475,000	—	11,875
Phillip D. Kramer	2004	$200,000	$850,000	$1,209,000	$13,745(1)
Executive V.P. and CFO	2003	200,000	500,000	—	12,745
	2002	200,000	275,000	—	11,745
George R. Coiner	2004	$200,000	$1,061,000(2)	$1,643,138	$13,730(1)
Senior Group Vice President	2003	200,000	719,600(2)	226,200	12,730
	2002	200,000	451,000(2)	—	11,651
W. David Duckett(3)	2004	$204,161	$933,505(4)	$—	$26,541(5)
President—PMC	2003	190,658	724,883(4)	—	—
(Nova Scotia Company)	2002	163,891	270,070(4)	—	—

(1) Our general partner matches 100% of employees' contributions to its 401(k) Plan in cash, subject to certain limitations in the plan. Includes $13,000 in such contributions for 2004. The remaining amount represents premium payments on behalf of the Named Executive Officer for group term life insurance. The amount shown does not include the value of perquisites and other benefits because they do not exceed $50,000 in the aggregate.

(2) Includes quarterly bonuses aggregating $561,000, $469,600 and $361,000 and an annual bonus of $500,000, $250,000 and $90,000 for 2004, 2003 and 2002, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years. For the quarterly bonuses, Mr. Coiner participates in a quarterly bonus arrangement based on EBITDA from our commercial activities during the quarter. Other participants include approximately 73 employees in the marketing and business development group. For 2004, the quarterly bonus pool totaled approximately $4.4 million.

(3) Salary and bonus for Mr. Duckett are presented in U.S. dollar equivalent, based on the exchange rates in effect on the dates payments were made.

(4) The 2004 bonus amount includes $798,151 under a bonus program established at the time of the CANPET acquisition and $135,354 under a special 2004 retention bonus associated with the CANPET acquisition. Under the bonus program at PMC (Nova Scotia) Company established at the time of the CANPET purchase, all employees of PMC (Nova Scotia) Company are eligible to participate. The plan is based on EBITDA, and includes a quarterly bonus pool consisting of 4% of quarterly EBITDA and an annual bonus pool consisting of 6% of EBITDA.

(5) Employer contributions to PMC (Nova Scotia) Company savings plan.

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

Messrs. Armstrong and Pefanis have employment agreements with our general partner. Mr. Armstrong is employed as Chairman and Chief Executive Officer. The initial three-year term of Mr. Armstrong's employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) 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 provided for a base salary of $330,000 per year, subject to annual review. In February 2005, the annual salary was increased to $375,000. 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 highest annual 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 initial three-year term of Mr. Pefanis' employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) 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 provided for a base salary of $235,000 per year, subject to annual review. In February 2005, the annual salary was increased to $300,000. 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.

1998 Long-Term Incentive Plan

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the 1998 LTIP include phantom units and unit options. The 1998 LTIP currently permits the grant of phantom units and unit options covering an aggregate of 1,425,000 common units delivered upon vesting of such phantom units or unit options. No options have been granted under the plan. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors has the right to alter or amend the 1998 LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, 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.

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, over the term of the plan we may issue new common units to satisfy delivery obligations under the grants. When we issue new common units upon vesting of grants, the total number of common units outstanding increases.

Phantom Units. A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). A substantial number of phantom units have vested in 2003 and 2004. As of December 31, 2004, giving effect to vested grants, grants of approximately 134,000 unvested phantom units under the 1998 LTIP remain outstanding 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, including tandem distribution equivalent rights with respect to phantom units.

Other than grants to directors (discussed below), none of the phantom units vested until November 2003. Since that time, approximately 927,000 phantom units have vested. Including grants to directors, approximately 418,000 units have been purchased and delivered or issued in satisfaction of vesting, after payment of cash-equivalents and netting for taxes. As a result of the vesting of these awards, we recognized an expense of approximately $28.8 million during 2003 and an additional expense of approximately $7.9 million during 2004.

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

Grants of 5,000 phantom 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 three vestings took place on June 8 of 2002, 2003 and 2004. See "—Compensation of Directors."

The following table shows the vesting of phantom units granted under the 1998 LTIP to the Named Executive Officers.

		2003 Vesting		2004 Vesting		Remaining Unvested Grants[2]	
Name	**Total Units**	**Units**	**Value[1]**	**Units**	**Value[1]**	**Units**	**Value[3]**
Greg L. Armstrong	70,000	—	—	52,500	$ 1,692,600	17,500	$ 660,450
Harry N. Pefanis	70,000	15,000	$ 452,400	52,500	$ 1,674,600	2,500	$ 94,350
Phillip D. Kramer	50,000	—	—	37,500	$ 1,209,000	12,500	$ 471,750
George R. Coiner	67,500	7,500	$ 226,200	50,625	$ 1,643,138	9,375	$ 353,813
W. David Duckett	—	—	—	—	—	—	

(1) As of vesting dates.

(2) With respect to remaining grants, vesting is contingent upon our achieving a specified distribution threshold of $2.50 annualized. Amounts shown do not include grants approved in 2005.

(3) As if vested on December 31, 2004, at a market closing price of $37.74 per unit.

Unit Option Plan. The unit option plan under our 1998 LTIP 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.

2005 Long-Term Incentive Plan

In January 2005, our unitholders approved the 2005 Plains All American GP LLC Long-Term Incentive Plan (the "2005 LTIP"). The 2005 LTIP provides for awards to our employees and directors. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the Compensation Committee (each an "Award"). Up to 3,000,000 units may be issued in satisfaction of Awards. Certain Awards may also include, in the discretion of the Compensation Committee, a "distribution equivalent right," or "DER," that entitles the grantee to a cash payment, either while the Award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the Award is outstanding.

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, over the term of the plan we may issue new common units to satisfy delivery obligations under the grants. When we issue new common units upon vesting of grants, the total number of common units outstanding increases.

The Compensation Committee and Board of Directors have approved grants under the 2005 LTIP of phantom units with associated DERs to the Named Executive Officers as follows: Mr. Armstrong—300,000 phantom units; Mr. Pefanis—200,000 phantom units; Mr. Kramer—100,000 phantom units; Mr. Coiner—80,000 phantom units; and Mr. Duckett—75,000 phantom units. The phantom units for Messrs Armstrong and Pefanis will vest incrementally solely upon achievement by the Partnership of annualized distributions of $2.60, $2.80 and $3.00 per unit and continued employment of at least 2, 4 and 5 years, respectively and any phantom units unvested after seven years will be forfeited. The phantom units granted to Messrs Kramer, Coiner and Duckett are also subject to incremental vesting upon attainment of similar distribution thresholds and similar minimum years of continued employment, provided however that any remaining unvested units will fully vest after six years.

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

Other Equity Grants

Certain other employees and officers have also received grants of equity not associated with the LTIP's described above, and for which we have no direct cost or reimbursement obligations. For example, in 2001 our general partner established a Performance Option Plan funded by common units owned by the general partner. See "Certain Relationships and Related Transactions—Transactions with Related Parties."

New tax rules concerning deferred compensation became effective January 1, 2005. We intend to operate all of our equity plans, and make any amendments thereto that may be necessary, for the plans and awards granted thereunder to comply with this new law.

Compensation of Directors

Each director of our general partner who is not an employee of our general partner is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Each non-employee director is currently paid an annual retainer fee of $45,000. 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 $30,000 annually, and the other members of the Audit Committee receive $15,000 annually. Mr. Petersen assigns any compensation he receives in his capacity as a director to EnCap Energy Capital Fund III, L.P. (EnCap III), which is controlled by EnCap Investments L.P., of which Mr. Petersen is a Managing Director. Mr. Capobianco assigns any compensation he receives in his capacity as a director to Vulcan Capital.

Except as described below, each non-employee director has received an LTIP award of 5,000 units in the aggregate. These units vest annually in 25% increments, subject to an automatic re-grant of the amount vested, such that the director will always have outstanding an award of 5,000 units. For Mr. Peterson and Mr. Capobianco, a cash equivalent payment will be made to EnCap III and Vulcan Capital, respectively, upon any vesting. The units vest in full upon the death or disability (as determined by the board) of the director. For any "independent" directors (as defined in the Third Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, as amended, and currently including Messrs. Goyanes, Smith and Symonds), the units will also vest full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the Board or is not reelected to the Board, unless such removal or failure to reelect is for "good cause," as defined in the letter granting the phantom units.

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. Our 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. See "Certain Relationships and Related Transactions."

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

Beneficial Ownership of Limited Partner Interest

Our common units outstanding represent 98% of our equity (limited partner interest). The 2% general partner interest is discussed separately below under the caption "Beneficial Ownership of General Partner Interest." The following table sets forth the beneficial ownership of limited partner units held by beneficial owners of 5% or more of the units, by directors and the Chief Executive Officer and the four other most highly compensated executive officers in 2004 (the "Named Executive

Officers") of our general partner and by all directors and executive officers as a group as of February 25, 2005.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)
Paul G. Allen	13,688,400(2)	20.2%
Vulcan Energy Corporation	12,390,120(3)	18.3%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	5,470,321(4)	8.1%
Greg L. Armstrong	213,992(5)(6)(7)	(8)
Harry N. Pefanis	145,027(6)(7)	(8)
George R. Coiner	54,276(6)(7)	(8)
Phillip D. Kramer	89,600(6)(7)	(8)
W. David Duckett	119,541(6)	(8)
David N. Capobianco	—(9)	(8)
Everardo Goyanes	7,450	(8)
Gary R. Petersen	5,700(10)	(8)
John T. Raymond	403,117(11)	(8)
Robert V. Sinnott	13,750(12)	(8)
Arthur L. Smith	10,000	(8)
J. Taft Symonds	18,750	(8)
All directors and executive officers as a group (23 persons)	1,250,769(6)(7)	1.8%

(1) Limited partner units constitute 98% of our equity, with the remaining 2% held by our general partner. Amounts shown include the 575,000 units issued in a private placement on February 25, 2005 to Plains Holdings II Inc. The beneficial ownership of our general partner is set forth in the table below under the caption "Beneficial Ownership of General Partner Interest." Giving effect to the indirect ownership by Vulcan Energy Corporation of a portion of our general partner, Mr. Allen may be deemed to beneficially own approximately 20.7% of our total equity. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(2) Mr. Allen owns approximately 88.38% of the outstanding shares of common stock of Vulcan Energy Corporation. Vulcan Energy Corporation is the indirect sole stockholder of Plains Holdings Inc. See Note 3 below. Mr. Allen also controls Vulcan Capital Private Equity I LLC ("Vulcan LLC"), which is the record holder of 1,298,280 common units. The address for Mr. Allen, Vulcan Energy Corporation and Vulcan LLC is 505 Fifth Avenue S, Suite 900, Seattle, Washington 98104. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy or any of its affiliates.

(3) Vulcan Energy Corporation is the indirect sole stockholder of Plains Holdings Inc., our former general partner. The common units are owned by Plains Holdings Inc. and its wholly owned subsidiary, Plains Holdings II Inc. The address for Plains Holdings Inc. and Plains Holdings II Inc. is 700 Louisiana, Suite 4150, Houston, Texas 77002.

(4) Richard A. Kayne is President, Chief Executive Officer and Director of Kayne Anderson Investment Management, Inc., which is the general partner of Kayne Anderson Capital Advisors, L.P. ("KACALP"). Various accounts (including KAFU Holdings, L.P., which owns a portion of our general partner) under the management or control of KACALP own 5,234,591 common units. Mr. Kayne may be deemed to beneficially own such units. In addition, Mr. Kayne directly owns or has sole voting and dispositive power over 235,730 common units. Mr. Kayne disclaims beneficial ownership of any of our partner interests other than units held by him or interests attributable to him by virtue of his interests in the accounts that own our partner interests. The address for Mr. Kayne and Kayne Anderson Investment Management Inc. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(5) Does not include the approximately 446,000 common units owned by our general partner, held for the purpose of satisfying its obligations under the Performance Option Plan. Mr. Armstrong disclaims any beneficial ownership of such units beyond his rights as a grantee under the plan. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—Performance Option Plan."

(6) Does not include unvested phantom units granted under the 1998 LTIP or the 2005 LTIP, none of which will vest within 60 days of the date hereof. See "Executive Compensation—1998 Long-Term Incentive Plan."

(7) Includes the following vested, unexercised options to purchase common units under the Performance Option Plan. Mr. Armstrong: 37,500; Mr. Pefanis: 27,500; Mr. Coiner: 21,250; Mr. Kramer: 22,500; directors and officers as a group: 161,875.

(8) Less than one percent.

(9) The Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (the "LLC Agreement") specifies that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Capobianco has been designated by Plains Holdings Inc., a wholly owned subsidiary of Plains Resources, of which he is a director and Vice President. Mr. Capobianco is also the Chairman and a Vice President of Vulcan Energy Corporation. Mr. Capobianco has the right to receive a performance-based fee based on the performance of the holdings of Vulcan Energy Corporation. Mr. Capobianco disclaims any deemed beneficial ownership of our partner interests held by Vulcan Energy Corporation or any of its affiliates beyond his pecuniary interest therein, if any. Mr. Capobianco owns an equity interest in, and has an indirect right to receive a performance-based fee based on the performance of the holdings of, Vulcan Capital Private Equity I LLC. Mr. Capobianco disclaims any deemed beneficial ownership of the units held by Vulcan Capital Private Equity I LLC beyond his pecuniary interest therein, if any.

(10) Pursuant to the LLC Agreement, Mr. Petersen has been designated by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is a Managing Director. Mr. Petersen disclaims any deemed beneficial ownership of any of our partner interests owned by E-Holdings III, L.P. or other affiliates of EnCap Investments L.P. beyond his pecuniary interest. The address for E-Holdings III, L.P. is 1100 Louisiana, Suite 3150, Houston, Texas 77002.

(11) Pursuant to the LLC Agreement, Mr. Raymond has been designated one of our directors by Sable Investments, L.P. Sable Investments, L.P. is controlled by James M. Flores, a director of Vulcan Energy Corporation and also the Chairman and Chief Executive Officer of Plains Exploration and Production Company ("PXP"). Mr. Raymond owns approximately 2% of the outstanding shares of common stock of Vulcan Energy Corporation. Mr. Raymond is a director and the Chief Executive Officer of Vulcan Energy Corporation. Mr. Raymond disclaims any deemed beneficial ownership of any units held by Sable Holdings, L.P. or its affiliates or Vulcan Energy Corporation or its affiliates.

(12) Pursuant to the LLC Agreement, Mr. Sinnott has been designated one of our directors by KAFU Holdings, L.P., which is controlled by Kayne Anderson Investment Management, Inc., of which he is a Vice President. Mr. Sinnott disclaims any deemed beneficial ownership of any units held by KAFU Holdings, L.P. or its affiliates, other than through his 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.

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 following table sets forth the effective ownership of Plains AAP, L.P. (after giving effect to proportionate ownership of Plains All American GP LLC, its 1% general partner).

Name and Address of Owner	Percentage Ownership of Plains AAP
Paul G. Allen(1) 505 Fifth Avenue S, Suite 900 Seattle, Washington 98104	44.000%
Vulcan Energy Corporation(2) 777 Walker, Suite 2400 Houston, TX 77002	44.000%
Sable Investments, L.P. 700 Milam, Suite 3100 Houston, TX 77002	20.000%
KAFU Holdings, L.P.(3) 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	16.418%
E-Holdings III, L.P.(4) 1100 Louisiana, Suite 3150 Houston, TX 77002	9.000%
PAA Management, L.P.(5) 333 Clay Street, #1600 Houston, TX 77002	4.000%
Wachovia Investors, Inc 301 South College Street, 12th Floor Charlotte, NC 28288	3.382%
Mark E. Strome 100 Wilshire Blvd., Suite 1500 Santa Monica, CA 90401	2.134%
Strome Hedgecap Fund, L.P 100 Wilshire Blvd., Suite 1500 Santa Monica, CA 90401	1.066%

(1) Mr. Allen owns approximately 88.38% of the outstanding shares of common stock of Vulcan Energy Corporation. Vulcan Energy Corporation, through its wholly owned subsidiary, Plains Holdings Inc., owns 44% of the equity of our general partner. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(2) Mr. Capobianco disclaims any deemed beneficial ownership of the interests held by Vulcan Energy Corporation beyond his pecuniary interest therein, if any. Mr. Raymond disclaims any deemed beneficial ownership of the interests held by Vulcan Energy Corporation or any of its affiliates other than through his approximately 2% ownership interest of the outstanding shares of common stock of Vulcan Energy Corporation.

(3) Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. other than through his 4.5% limited partner interest in KAFU Holdings, L.P.

(4) Mr. Petersen disclaims any deemed beneficial ownership of the interests owned by E-Holdings III, L.P. beyond his pecuniary interest.

(5) PAA Management, L.P. is owned entirely by certain members of senior management, including Messrs. Armstrong (approximately 26%), Pefanis (approximately 14.5%), Kramer (approximately 9.5%), Coiner (approximately 9.5%) and Duckett (approximately 4.5%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Directors and executive officers as a group own approximately 95% of PAA Management, L.P. Mr. Armstrong disclaims any beneficial ownership of the general partner interest owned by Plains AAP, L.P., other than through his ownership interest in PAA Management, L.P.

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*
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
1998 Long Term Incentive Plan	133,625(1)	N/A(2)	460,101(1)(3)
2005 Long Term Incentive Plan	—(4)	N/A(2)	—(3)
Equity compensation plans not approved by unitholders:			
1998 Long Term Incentive Plan	(1) (5)	N/A(2)	(6)
Performance Option Plan	(7)	15.91(8)	(9)

* As of December 31, 2004.

(1) As originally instituted by our former general partner prior to our initial public offering, the 1998 LTIP contemplated issuance of up to 975,000 common units to satisfy awards of phantom units. Upon vesting, these awards could be satisfied either by (i) primary issuance of units by us or (ii) cash settlement or purchase of units by our general partner with the cost reimbursed by us. In 2000, the 1998 LTIP was amended, as provided in the plan, without unitholder approval to increase the maximum awards to 1,425,000 phantom units; however, we can issue no more than 975,000 new units to satisfy the awards. Any additional units must be purchased by our general partner in the open market or in private transactions and be reimbursed by us. As of December 31, 2004, we have issued approximately 381,000 common units in satisfaction of vesting under the 1998 LTIP. The number of units presented in column (a) assumes that all remaining grants will be satisfied by the issuance of new units upon vesting. In fact, a substantial number of phantom units that vested in 2003 and 2004 were satisfied without the issuance of units. These phantom units were settled in cash or withheld for taxes. See "1998 Long-Term Incentive Plan." Any units not issued upon vesting will become "available for future issuance" under column (c).

(2) Phantom unit awards under the 1998 LTIP vest without payment by recipients. See "1998 Long-Term Incentive Plan—Restricted Unit Plan."

(3) In accordance with Item 201(d) of Regulation S-K, this column (c) excludes the securities disclosed in column (a). However, as discussed in footnote (1) above, any phantom units represented in column (a) that are not satisfied by the issuance of units become "available for future issuance." See "1998 Long-Term Incentive Plan."

(4) The 2005 Long Term Incentive Plan was approved by our unitholders in January 2005. Accordingly, there were no outstanding awards as of December 31, 2004. In February 2005, the Board of Directors and Compensation Committee approved grants of approximately 1,900,000 phantom units. The 2005 LTIP contemplates issuance or delivery of up to 3,000,000 units to satisfy awards under the plan.

(5) Although awards for units may from time to time be outstanding under the portion of the 1998 LTIP not approved by unitholders, all of these awards must be satisfied in cash or out of units purchased by our general partner and reimbursed by us. None will be satisfied by "units issued upon exercise/vesting."

(6) Awards for up to 413,750 phantom units may be granted under the portion of the 1998 LTIP not approved by unitholders; however, no common units are "available for future issuance" under the plan, because all such awards must be satisfied with cash or out of units purchased by our general partner and reimbursed by us.

(7) Our general partner has adopted and maintains a Performance Option Plan for officers and key employees pursuant to which optionees have the right to purchase units from the general partner. The units that will be sold under the plan were contributed to the general partner by certain of its owners in connection with the transfer of a majority of our general partner interest in 2001 (the "General Partner Transition") without economic cost to the Partnership. Thus, there will be no

units "issued upon exercise/vesting of outstanding options." Approximately 391,000 unit options have been granted out of the 450,000 units originally available under the plan. See footnote (9) below and "—Other Equity Grants."

(8) As of December 31, 2004, the strike price for all outstanding options under the Performance Option Plan was $15.91 per unit. The strike price decreases as distributions are paid. Future grants may include different pricing elements. See "—Other Equity Grants."

(9) In connection with the General Partner Transition, certain of the investors in our general partner contributed 450,000 subordinated units (now converted into common units) to our general partner to fund the Performance Option Plan. Options for approximately 388,000 units are currently outstanding and approximately 59,000 units are available for future 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). 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	$ 126,000	$ 2,571	$ 128,571	2.0%
$1.98	$ 138,600	$ 4,795	$ 143,395	3.3%
$2.45	$ 171,500	$ 15,762	$ 187,262	8.4%
$2.60	$ 182,000	$ 19,262	$ 201,262	9.6%
$2.80	$ 196,000	$ 28,595	$ 224,595	12.7%
$3.00	$ 210,000	$ 42,595	$ 252,595	16.9%

(1) In thousands.

(2) Assumes 70,000,000 units outstanding. Actual number of units outstanding as of December 31, 2004 was 67,293,108. 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

As of December 31, 2004 Vulcan Energy owned an effective 44% of our general partner interest, as well as approximately 18.3% of our outstanding limited partner units. Mr. John Raymond, one of our directors, is a director and the Chief Executive Officer of Vulcan Energy. Mr. Raymond was designated as a member of our board by Sable Investments, L.P., which is controlled by Mr. James C. Flores. Mr. Flores is a director of Vulcan Energy, and is the Chairman and Chief Executive Officer of Plains Exploration and Production Company ("PXP"). We have ongoing relationships with Plains

Resources, a wholly owned subsidiary of Vulcan Energy. These relationships include but are not limited to:

- a separation agreement entered into in 2001 in connection with the transfer of interests in our general partner 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 indemnified, and maintains liability insurance (through June 8, 2007) 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, including certain non-compete obligations of Plains Resources.

- 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 of Plains Resources equity production for a fee of $0.20 per barrel. The fee is subject to adjustment in November 2006 based on then-existing market conditions. For the year ended December 31, 2004, Plains Resources produced approximately 2,000 barrels per day that were subject to the Marketing Agreement. We paid approximately $28.3 million for such production and recognized segment profit of approximately $0.1 million under the terms of that agreement. In our opinion, these purchases were made at prevailing market prices. Because Plains Resources divested itself of most of its producing properties at the end of 2002, we do not expect material amounts of crude oil to be subject to this agreement. As currently in effect, the Marketing Agreement (as well as the Omnibus Agreement described above) will terminate upon a "change of control" of Plains Resources or our general partner. The recent purchase of Plains Resources by Vulcan Energy would have constituted a change of control under both the Marketing Agreement and the Omnibus Agreement. In July 2004, we amended and restated the Marketing Agreement and the Omnibus Agreement to except the Vulcan transaction from the change of control provisions.

- Plains Resources has agreed to pay $150,000 in plaintiff's attorney's fees in connection with the settlement of certain litigation in which we are a defendant. See Item 3. "Legal Proceedings"

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 the Plains Resources Marketing agreement. For the year ended December 31, 2004, PXP produced approximately 22,000 barrels per day that were subject to the Marketing Agreement. We paid approximately $328.3 million for such production and recognized segment profit of approximately $1.4 million. In our opinion, these purchases were made at prevailing market prices. We are also party to 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. In July 2004, we amended and restated the Marketing Agreement to, among other things, reflect the change in parties as a result of the spin-off. We sell PXP's crude under sales contracts that range from one year to seven years in length. In October 2004, we further amended the PXP Marketing Agreement to exclude any newly acquired properties and to adjust the marketing fee to $0.15 per barrel for any new contracts entered into after January 1, 2005.

1998 Long-Term Incentive Plan

Our general partner maintains the 1998 LTIP for employees and directors of our general partner and its affiliates who perform services for us. The 1998 LTIP consists of two components, a restricted unit plan and a unit option plan. The 1998 LTIP permits the grant of restricted units and unit options covering delivery of an aggregate of 1,425,000 common units. No options have been granted under the plan. 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 (or cash equivalent) upon the vesting of the phantom unit. As of December 31, 2004, approximately 418,000 common units have been issued, or purchased and delivered, upon vesting and grants of approximately 134,000 phantom units remain outstanding to employees, officers and directors of our general partner. See "Management—Executive Compensation."

2005 Long-Term Incentive Plan

In January 2005, our unitholders approved the 2005 LTIP. The 2005 LTIP provides for awards to our employees and directors. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the Compensation Committee (each an "Award"). Up to 3,000,000 units may be issued in satisfaction of Awards. Certain Awards may also include DERs, in the discretion of the Compensation Committee. In February 2005, our Board of Directors and Compensation Committee approved grants of approximately 1,900,000 phantom units (a substantial portion of which include DERs) under the 2005 LTIP. See "Management—Executive Compensation."

Performance Option Plan

In 2001, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common 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 391,000 units have been granted. Of this amount, 75,000, 55,000, 45,000 and 42,500 were granted to Messrs. Armstrong, Pefanis, Kramer and Coiner, respectively, and approximately 346,000 to executive officers as a group. These 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 in 2002, and 25% of the options vested. The second level was reached in 2004, and an incremental 25% of the options vested. 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 December 31, 2004, the purchase price was $15.91 per unit. The terms of future grants may differ from the existing grants. Because the 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.

The American Jobs Creation Act of 2004 (the "Jobs Act") includes, among other things, provisions with respect to deferred compensation. These provisions, which became effective as of January 1, 2005, can impose substantial tax penalties with respect to employee options that have an exercise price of less than the value of the underlying security at the date of grant. We are currently assessing the effect of the Jobs Act on the options and the Performance Option Plan, and anticipate amending the terms of the outstanding, unvested options and the Performance Option Plan or taking other appropriate action to conform to the requirements of the Jobs Act and avoid or minimize any tax penalty.

Stock Option Replacement

In connection with the General Partner Transition, certain members of the management team that had been employed by Plains Resources, including Messrs. Armstrong, Pefanis and Kramer, 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, which are now common units pursuant to conversion, with a value equal to the spread on the unvested options, with distribution equivalent rights from the date of grant. The grant included 8,548, 4,602 and 9,742 units to Messrs. Armstrong, Pefanis and Kramer, respectively. The units vested 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 administered the vesting and delivery of the units under the grants. Because the units necessary to satisfy the delivery requirements under the grants were provided by Plains Resources, we had no obligation to reimburse the general partner for the cost of such units.

CANPET Energy Group Inc.

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 $24.6 million plus excess inventory at the closing date of approximately $25.0 million. A portion of the purchase price, payable in common units or cash, at our option, was deferred subject to various performance standards being met. On April 30, 2004, we satisfied the deferred payment with the issuance of approximately 385,000 common units (representing approximately $13.1 million in value as of the date of issuance) and the payment of $6.5 million in cash. In addition, an incremental $3.7 million in cash was paid for the distributions that would have been paid on the common units had they been outstanding since the effective date of the acquisition. Mr. W. David Duckett, the President of PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P., owns approximately 37.8% of CANPET, and received a proportionate share of the proceeds from the contingent payment of purchase price for the CANPET assets.

Tank Car Lease and CANPET

In connection with the CANPET 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 Mr. W. David Duckett. Mr. Duckett owns a 22% interest in Pivotal.

Class B Common Units

In May 1999, we sold 1,307,190 unregistered Class B common units (the "Class B common units") to our general partner at the time, Plains All American Inc., a wholly owned subsidiary of Plains Resources Inc., pursuant to Rule 4(2) of the Securities Act. We received $19.125 per Class B common unit, a price equal to the then-market value of our common units for total proceeds of approximately $25 million. We used the net proceeds from the offering to defray costs associated with our acquisition of Scurlock Permian LLC and certain other pipeline assets from Marathon Ashland Petroleum LLC. In

January 2005, our common unitholders approved a change in the terms of the Class B Common units such that they were immediately convertible into an equal number of Common Units at the option of the holders, and in February 2005, all of the Class B common units converted.

Class C Common Units

In April 2004, we sold 3,245,700 unregistered Class C common units (the "Class C common units") to a group of investors comprised of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital pursuant to Rule 4(2) under the Securities Act. For more detailed information with respect to our relationship with Kayne Anderson Capital Advisors and Vulcan Capital, see "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters." We received $30.81 per Class C common unit, an amount which represented 94% of the average closing price of our common units for the twenty trading days immediately ending and including March 26, 2004. Net proceeds from the private placement, including the general partner's proportionate capital contribution and expenses associated with the sale, were approximately $101.0 million. We used the net proceeds from the offering to repay indebtedness under our revolving credit facility incurred in connection with the Link acquisition. In January 2005, our common unitholders approved a change in the terms of the Class C Common units such that they were immediately convertible into an equal number of Common Units at the option of the holders, and in February 2005, all of the Class C common units converted.

Other

An affiliate of Kayne Anderson Investment Management, Inc. participated in our December 2003 and July 2004 equity offerings. In the aggregate for both offerings, it earned approximately $672,000 in commissions for its participation.

Item 14. ***Principal Accountant Fees and Services***

All services provided by our independent auditor are subject to pre-approval by our Audit Committee. The Audit Committee has instituted a policy that describes certain pre-approved non-audit services. We believe that the description of services is designed to be sufficiently detailed as to particular services provided, such that (i) management is not required to exercise judgment as to whether a proposed service fits within the description and (ii) the Audit Committee knows what services it is being asked to pre-approve. The Audit Committee is informed of each engagement of the independent auditor to provide services under the policy.

The following table details the aggregate fees billed for professional services rendered by our independent auditor (in thousands):

	Year Ended December 31,	
	2004	2003
Audit fees	$ 1,995	$ 852
Audit-related fees	160	147
Tax fees	825	401
All other fees	590	315
Total	$ 3,570	$ 1,715

Expenditures classified as "Audit fees" above include those related to our annual audit (including internal control evaluation and reporting), audits of our general partner and certain joint ventures of which we are the operator, and work performed on our registration of publicly-held debt and equity. "Audit-related fees" are primarily comprised of audits of our benefit plans and carve-out audits of acquired companies. "Tax fees" are related to tax processing as well as the preparation of Forms K-1 for our unitholders. "All other fees" primarily consist of those associated with due diligence performed on potential acquisitions.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(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) as amended by Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of April 15, 2004 (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the period ended March 31, 2004)
3.2	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the period ended March 31, 2004)
3.3	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the period ended March 31, 2004)
3.4	—	Second Amendment dated as of July 23, 2004 to Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (incorporated by reference to Exhibit 3.1 to the Partnership's Current Report on Form 8-K filed July 27, 2004)
3.5	—	Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.1 to Plains All American Pipeline, L.P.'s Current Report on Form 8-K filed on June 11, 2001)
3.6	—	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to Plains All American Pipeline, L.P.'s Registration Statement on Form S-3 filed on August 27, 2001)
3.7	—	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Plains All American Pipeline, L.P.'s Registration Statement on Form S-3 filed on August 27, 2001)
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002)
4.2	—	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)
4.3	—	Second Supplemental Indenture dated as of December 10, 2003. (incorporated by reference to Exhibit 4.4 to Annual Report on Form 10-K for the Year Ended December 31, 2003)

4.4	—	Third Supplemental Indenture (Series A and Series B 4.750% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168)
4.5	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168)
4.6	—	Exchange and Registration Rights Agreement (4.750% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-4, File No. 333-121168)
4.7	—	Exchange and Registration Rights Agreement (5.875% Senior Notes due 20016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-4, File No. 333-121168)
4.8	—	Class C Common Unit Purchase Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners, L.P., Kayne Anderson MLP Fund, L.L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated March 31, 2004 (incorporated by reference to Exhibit 4.1 to the quarterly report on Form 10 Q for the period ended March 31, 2004)
4.9	—	Registration Rights Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Kayne Anderson MLP Fund, L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated April 15, 2004 (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10 Q for the period ended March 31, 2004)
10.1	—	Credit Agreement dated November 2, 2004 among Plains All American Pipeline, L.P. (as US Borrower), PMC (Nova Scotia) Company and Plains Marketing Canada, L.P. (as Canadian Borrowers), and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the period ended September 30, 2004)
10.2	—	Restated Credit Facility (Uncommitted Senior Secured Discretionary Contango Facility) dated November 19, 2004 among Plains Marketing, L.P. and the lenders named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 24, 2004)
10.3	—	Amended and Restated Marketing Agreement, dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the period ended June 30, 2004)
10.4	—	Amended and Restated Omnibus Agreement, dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC. (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the period ended June 30, 2004)

10.5	—	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)
10.6	—	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)
10.7	—	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)
10.8**	—	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)
10.9**	—	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Annex A to Proxy Statement filed December 7, 2004.)
10.10**	—	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) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed June 30, 2003)
10.11**	—	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)
10.12**	—	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)
10.13**	—	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)
10.14	—	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)
10.15	—	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)
10.16	—	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)
10.17	—	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)

10.18	—	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)
10.19**	—	Plains All American Inc., 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.05 to Annual Report on Form 10-K for the Year Ended December 31, 1998)
10.20+**	—	PMC (Nova Scotia) Company bonus program
10.21+**	—	Quarterly bonus summary
10.22+**	—	Directors' Compensation Summary
10.23	—	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to Annual Report on Form 10-K for the Year Ended December 31, 2001)
10.24**	—	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed February 23, 2005)
10.25**	—	Form of LTIP Grant Letter—executive officers (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed February 23, 2005)
10.26**	—	Form of LTIP Grant Letter—independent directors (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed February 23, 2005)
10.27**	—	Form of LTIP Grant Letter—designated directors (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K filed February 23, 2005)
10.28**	—	Form of LTIP Grant Letter—payment to entity (incorporated by reference to Exhibit 10.5 to Current Report on Form 8-K filed February 23, 2005)
21.1	—	List of Subsidiaries of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 21.1 to Registration Statement on Form S-1, File No. 333-119738)
23.1+	—	Consent of PricewaterhouseCoopers LLP
31.1+	—	Certification of Principal Executive Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a)
31.2+	—	Certification of Principal Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a)
32.1+	—	Certification of Principal Executive Officer pursuant to 18 USC § 1350
32.2+	—	Certification of Principal Financial Officer pursuant to 18 USC § 1350

\+ Filed herewith

** Management compensatory plan or arrangement

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: March 2, 2005

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: March 2, 2005

By: /s/ PHILLIP D. KRAMER

Phillip D. Kramer, Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial 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: March 2, 2005
/s/ HARRY N. PEFANIS **Harry N. Pefanis**	President and Chief Operating Officer of Plains All American GP LLC	Date: March 2, 2005
/s/ PHILLIP D. KRAMER **Phillip D. Kramer**	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	Date: March 2, 2005
/s/ TINA L. VAL **Tina L. Val**	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	Date: March 2, 2005
/s/ EVERARDO GOYANES **Everardo Goyanes**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ GARY R. PETERSEN **Gary R. Petersen**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ JOHN T. RAYMOND **John T. Raymond**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ ROBERT V. SINNOTT **Robert V. Sinnott**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ DAVID N. CAPOBIANCO **David N. Capobianco**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ ARTHUR L. SMITH **Arthur L. Smith**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ J. TAFT SYMONDS **J. Taft Symonds**	Director of Plains All American GP LLC	Date: March 2, 2005

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Plains All American Pipeline, L.P.'s management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" published by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the Company's internal control over financial reporting. Based on that evaluation, management has concluded that the Company's internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

/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)

/s/ PHILLIP D. KRAMER

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

March 2, 2005

Report of Independent Registered Public Accounting Firm

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

We have completed an integrated audit of Plains All American Pipeline, L.P.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

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 at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements 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 1 to the consolidated financial statements, the Partnership changed its method of accounting for pipeline linefill in third party assets effective January 1, 2004.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Partnership maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in COSO, is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the COSO. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Partnership's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2005

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	December 31, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 12,988	$ 4,137
Trade accounts receivable, net	521,785	590,645
Inventory	498,200	105,967
Other current assets	68,229	32,225
Total current assets	1,101,202	732,974
PROPERTY AND EQUIPMENT	1,911,509	1,272,634
Accumulated depreciation	(183,887)	(121,595)
	1,727,622	1,151,039
OTHER ASSETS		
Pipeline linefill in owned assets	168,352	95,928
Inventory in third party assets	59,279	26,725
Other, net	103,956	88,965
Total assets	$ 3,160,411	$ 2,095,631
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 850,912	$ 603,460
Due to related parties	32,897	26,981
Short-term debt	175,472	127,259
Other current liabilities	54,436	44,219
Total current liabilities	1,113,717	801,919
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	151,753	70,000
Senior notes, net of unamortized discount of $2,729 and $1,009, respectively	797,271	448,991
Other long-term liabilities and deferred credits	27,466	27,994
Total liabilities	2,090,207	1,348,904
COMMITMENTS AND CONTINGENCIES (NOTES 11 and 12)		
PARTNERS' CAPITAL		
Common unitholders (62,740,218 and 49,502,556 units outstanding at December 31, 2004, and December 31, 2003, respectively)	919,826	744,073
Class B common unitholder (1,307,190 units outstanding at each date)	18,775	18,046
Class C common unitholders (3,245,700 units and no units outstanding at December 31, 2004, and December 31, 2003, respectively)	100,423	—
Subordinated unitholders (no units and 7,522,214 units outstanding at December 31, 2004, and December 31, 2003, respectively)	—	(39,913)
General partner	31,180	24,521
Total partners' capital	1,070,204	746,727
Total liabilities and partners' capital	$ 3,160,411	$ 2,095,631

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)

	Twelve Months Ended December 31,		
	2004	2003	2002
REVENUES			
Crude oil and LPG sales (includes approximately $11,246,951, $6,124,895 and $4,140,830, respectively, related to buy/sell transactions, see Note 2)	$ 20,184,319	$ 11,952,623	$ 7,892,405
Other gathering, marketing, terminalling and storage revenues	38,310	32,052	29,366
Pipeline margin activities revenues (includes approximately $149,797, $166,165 and $95,826, respectively, related to buy/sell transactions, see Note 2)	575,222	505,287	382,513
Pipeline tariff activities revenues	177,619	99,887	79,939
Total revenues	20,975,470	12,589,849	8,384,223
COSTS AND EXPENSES			
Crude oil and LPG purchases and related costs (includes approximately $11,137,669, $5,967,165 and $4,026,245, respectively, related to buy/sell transactions, see Note 2)	19,870,865	11,746,382	7,741,185
Pipeline margin activities purchases (includes approximately $142,538, $159,231 and $87,554, respectively, related to buy/sell transactions, see Note 2)	553,707	486,154	362,311
Field operating costs (excluding LTIP charge)	218,548	134,177	106,436
LTIP charge—operations	918	5,727	—
General and administrative expenses (excluding LTIP charge)	75,735	49,969	45,663
LTIP charge—general and administrative	7,013	23,063	—
Depreciation and amortization	67,241	46,821	34,068
Total costs and expenses	20,794,027	12,492,293	8,289,663
Gain on sales of assets	580	648	—
Asset impairment	(2,000)	—	—
OPERATING INCOME	180,023	98,204	94,560
OTHER INCOME/(EXPENSE)			
Interest expense (net of capitalized interest of $544, $524 and $773)	(46,676)	(35,226)	(29,057)
Interest and other income (expense), net	(211)	(3,530)	(211)
Income before cumulative effect of change in accounting principle	133,136	59,448	65,292
Cumulative effect of change in accounting principle	(3,130)	—	—
NET INCOME	$ 130,006	$ 59,448	$ 65,292
NET INCOME-LIMITED PARTNERS	$ 119,286	$ 53,473	$ 60,912
NET INCOME-GENERAL PARTNER	$ 10,720	$ 5,975	$ 4,380
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 1.94	$ 1.01	$ 1.34
Cumulative effect of change in accounting principle	(0.05)	—	—
Basic net income per limited partner unit	$ 1.89	$ 1.01	$ 1.34
DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 1.94	$ 1.00	$ 1.34
Cumulative effect of change in accounting principle	(0.05)	—	—
Diluted net income per limited partner unit	$ 1.89	$ 1.00	$ 1.34
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	63,277	52,743	45,546
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	63,277	53,400	45,546

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,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 130,006	$ 59,448	$ 65,292
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	67,241	46,821	34,068
Gain on sales of assets	(580)	(648)	—
Cumulative effect of change in accounting principle	3,130	—	—
Allowance for doubtful accounts	400	360	146
Inventory valuation adjustment	2,032	—	—
SFAS 133 non-cash mark-to-market adjustment	(994)	(363)	(243)
Gain on foreign currency revaluation	(4,954)	—	—
Non-cash amortization of terminated interest rate swap	1,486	—	—
Net cash paid for terminated swaps	(1,465)	(6,152)	—
Loss on refinancing of debt	658	3,272	—
LTIP charge	7,931	28,790	—
Impairment of long-lived assets	2,000	—	—
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other assets	(30,364)	(102,005)	(136,480)
Inventory	(398,671)	(38,941)	105,944
Accounts payable and other liabilities	327,449	121,274	107,265
Inventory in third-party assets	(7,248)	—	—
Due to related parties	5,911	3,452	8,962
Net cash provided by operating activities	103,968	115,308	184,954
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions (Note 3)	(535,266)	(168,359)	(324,628)
Additions to property and equipment	(116,944)	(65,416)	(40,590)
Cash paid for linefill on assets owned	(1,989)	(46,790)	(11,060)
Proceeds from sales of assets	3,012	8,450	1,437
Net cash used in investing activities	(651,187)	(272,115)	(374,841)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on long-term revolving credit facilities and other	64,893	62,473	(42,144)
Net borrowings on working capital revolving credit facility	62,900	25,300	—
Net repayments on short-term letter of credit and hedged inventory facilities	(20,090)	(6,197)	(4,770)
Principal payments on senior secured term loans	—	(297,000)	(3,000)
Cash paid in connection with financing arrangements	(5,073)	(5,191)	(5,435)
Net proceeds from the issuance of common units (Note 6)	262,132	250,341	145,046
Proceeds from the issuance of senior notes	348,068	249,340	199,600
Distributions paid to unitholders and general partner	(158,352)	(121,822)	(99,841)
Net cash provided by financing activities	554,478	157,244	189,456
Effect of translation adjustment on cash	1,592	199	421
Net increase (decrease) in cash and cash equivalents	8,851	636	(10)
Cash and cash equivalents, beginning of period	4,137	3,501	3,511
Cash and cash equivalents, end of period	$ 12,988	$ 4,137	$ 3,501
Cash paid for interest, net of amounts capitalized	$ 40,780	$ 36,382	$ 28,550

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 Units		Class B Common Units		Class C Common Units		
	Units	Amount	Units	Amount	Units	Amount (unaudited)	Units
Balance at December 31, 2001	31,916	$ 408,562	1,307	$ 19,534	—	$ —	1(
Issuance of common units	6,325	142,013	—	—	—	—	
Net income	—	45,857	—	1,736	—	—	
Distributions	—	(70,821)	—	(2,762)	—	—	
Other comprehensive loss	—	(1,183)	—	(45)	—	—	
Balance at December 31, 2002	38,241	$ 524,428	1,307	$ 18,463	—	$ —	1(
Issuance of common units	8,736	245,093	—	—	—	—	
Issuance of common units under LTIP	18	555	—	—	—	—	
Net income	—	41,278	—	1,370	—	—	
Conversion of subordinated units	2,507	(9,823)	—	—	—	—	(2
Distributions	—	(89,801)	—	(2,860)	—	—	
Other comprehensive income	—	32,343	—	1,073	—	—	
Balance at December 31, 2003	49,502	$ 744,073	1,307	$ 18,046	—	$ —	7
Issuance of common units	4,968	157,568	—	—	—	—	
Issuance of common units under LTIP	362	11,772	—	—	—	—	
Private placement of Class C common units	—	—	—	—	3,246	98,782	
Issuance of units for acquisition contingent consideration	385	13,082	—	—	—	—	
Distributions	—	(134,175)	—	(3,009)	—	(5,648)	
Other comprehensive income	—	59,886	—	1,248	—	3,098	
Net income	—	111,161	—	2,490	—	4,191	
Conversion of subordinated units	7,523	(43,541)	—	—	—	—	(7
Balance at December 31, 2004	62,740	$ 919,826	1,307	$ 18,775	3,246	$ 100,423	

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

	Year Ended December 31, 2004	2003	2002
	(in thousands)		
Net income	$ 130,006	$ 59,448	$ 65,292
Other comprehensive income (loss)	64,702	46,595	(1,684)
Comprehensive income	$ 194,708	$ 106,043	$ 63,608

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

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
	(in thousands)		
Balance at December 31, 2001	$ (4,740)	$ (8,002)	$ (12,742)
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
2002 Activity	(3,467)	1,783	(1,684)
Balance at December 31, 2002	(8,207)	(6,219)	(14,426)
Reclassification adjustments for settled contracts	(28,151)	—	(28,151)
Changes in fair value of outstanding hedge positions	28,666	—	28,666
Currency translation adjustment	—	46,080	46,080
2003 Activity	515	46,080	46,595
Balance at December 31, 2003	(7,692)	39,861	32,169
Reclassification adjustments for settled contracts	13,262	—	13,262
Changes in fair value of outstanding hedge positions	20,367	—	20,367
Currency translation adjustment	—	31,073	31,073
2004 Activity	33,629	31,073	64,702
Balance at December 31, 2004	$ 25,937	$ 70,934	$ 96,871

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. ("PAA") is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquified petroleum gas and natural gas related petroleum products collectively as "LPG." We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada.

Our 2% general partner interest is 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, who devote 100% of their efforts to the management of the Partnership. 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. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners with interests ranging from 44% to 3.2%.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2004 and 2003, and the consolidated results of our operations, cash flows, changes in partners' capital, comprehensive income (loss) and changes in accumulated other comprehensive income for the years ended December 31, 2004, 2003 and 2002. All significant intercompany transactions have been eliminated. Certain reclassifications were made to prior periods to conform with the current period presentation. The accompanying consolidated financial statements of PAA include PAA and all of its wholly-owned subsidiaries. Investments in 50% or less owned affiliates, over which the Company has significant influence, are accounted for by the equity method.

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory" (a current asset), at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is now reflected as a separate line item within other assets on the consolidated balance sheet.

This change in accounting principle is effective January 1, 2004 and is reflected in the consolidated statement of operations for the year ended December 31, 2004 and the consolidated balance sheets as of December 31, 2004 and 2003 included herein. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The pro forma impact for the year ended December 31, 2003 would have been an increase to net income of approximately $2.0 million ($0.04 per basic and diluted limited partner unit) resulting in pro forma net income of $61.5 million and pro forma basic net income per limited partner unit of $1.05 and pro forma diluted net income per limited partner unit of $1.04. The pro forma impact for the year ended December 31, 2002 would have been a decrease to net income of approximately $0.1 million (no impact to basic and diluted limited partner unit) resulting in pro forma net income of $65.2 million and pro forma basic net income per limited partner unit of $1.34 and pro forma diluted net income per limited partner unit of $1.34.

In conjunction with this change in accounting principle, we have classified cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification of cash flows from operating activities. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 increased to $115.3 million from $68.5 million and to $185.0 million from $173.9 million, respectively. Net cash used in investing activities for the years ended December 31, 2003 and 2002 increased to $272.1 million from $225.3 million and $374.8 million from $363.8 million, respectively.

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: (i) accruals related to purchases and sales, (ii) mark-to-market estimates pursuant to Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting For Derivative Instruments and Hedging Activities", as amended, (iii) contingent liability accruals and (iv) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Buy/sell transactions. The Emerging Issues Task Force ("EITF") is currently considering Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," ("EITF No. 04-13"), which relates to buy/sell transactions. The issues to be addressed by the EITF are i) under what circumstances should two or more transactions with the same counterparty be viewed as a single nonmonetary transaction within the scope of APB No. 29; and ii) if nonmonetary transactions within the scope of APB No. 29 involve inventory, are there any circumstances under which the transactions should be recognized at fair value.

Buy/sell transactions are contractual arrangements in which we agree to buy a specific quantity and quality of crude oil or LPG to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of crude oil or LPG at a different location, usually with the same counterparty. These arrangements are generally designed to increase our margin through a variety of methods, including reducing our transportation or storage costs or acquiring a grade of crude oil that more closely matches our physical delivery requirement to one of our other customers. The value difference between purchases and sales is referred to as margin and is primarily due to grade, quality or location differentials. All buy/sell transactions result in us making or receiving physical delivery of the product, involve the attendant risks and rewards of ownership, including title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk, and such transactions are settled in cash similar to all other purchases and sales. Accordingly, such transactions are recorded in both revenues and purchases as separate sales and purchase transactions on a "gross" basis.

We believe that buy/sell transactions are monetary in nature and thus outside the scope of APB Opinion No. 29, "Accounting for Nonmonetary Transactions" ("APB No. 29"). Additionally, we have evaluated EITF No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" ("EITF No. 99-19") and, based on that evaluation, we believe that recording these transactions on a gross basis is appropriate. If the EITF were to determine that these transactions should be accounted for as monetary transactions on a gross basis, no change in our accounting policy for buy/sell transactions would be necessary. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions qualifying for fair value recognition and require a net presentation of such transactions, the amounts of revenues and purchases associated with buy/sell transactions would be netted in our consolidated statement of operations, but there would be no effect on operating income, net income or cash flows from operating activities. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions not qualifying for fair value recognition, these amounts of revenues and purchases would be netted in our consolidated statement of operations and there could be an impact on operating income and net income related to the timing of the ultimate sale of product purchased in the "buy" side of the buy/sell transaction. However, we do not believe any impact on operating income, net income or cash flows from operating activities would be material.

Gathering, Marketing, Terminalling and Storage Segment Revenues. Revenues from crude oil and LPG sales are recognized at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Sales of crude oil and LPG consist of outright sales contracts and buy/sell arrangements which are booked gross as well as barrel exchanges which are booked net.

Terminalling and storage revenues, which are classified as other revenues on the income statement, consist of (i) storage fees from actual storage used on a month-to-month basis; (ii) storage fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer on a given month; and (iii) terminal throughput charges to pump crude oil to connecting carriers. Revenues on storage are recognized ratably over the term of the contract. Terminal throughput charges are recognized as the crude oil exits the terminal and is delivered to the connecting crude oil carrier. Any throughput volumes in transit at the end of a given month are treated as third party inventory and do not incur storage fees. All terminalling and storage revenues are based on actual volumes and rates.

Pipeline Segment Revenues. Pipeline margin activities primarily consist of the purchase and sale of crude oil shipped on our San Joaquin Valley system from barrel exchanges and buy/sell arrangements. Revenues associated with these activities are recognized at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Revenues for these transactions are recorded gross except in the case of barrel exchanges that are net settled. All of our pipeline margin activities revenues are based on actual volumes and prices. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil at a published tariff as well as fees associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized. All pipeline tariff and fee revenues are based on actual volumes and rates.

Purchases and Related Costs

Purchases and related costs include: (i) the cost of crude oil and LPG purchased in outright purchases as well as buy/sell arrangements; (ii) third party transportation and storage, whether by pipeline, truck or barge; and (iii) expenses to issue letters of credit to support these purchases. These purchases are accrued at the time title transfers to us which occurs upon receipt of the product.

Operating Expenses and General and Administrative Expenses

Operating expenses consist of various field and pipeline operating expenses including fuel and power costs, telecommunications, labor costs for truck drivers and pipeline field personnel, maintenance costs, regulatory compliance, environmental remediation, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs, certain information system and legal costs, office rent, contract and consultant costs, and audit and tax fees.

Foreign Currency Transactions

Assets and liabilities of subsidiaries with a functional currency other than the U.S. Dollar are translated at period end rates of exchange and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income in partners' capital. Gains and losses from foreign currency transactions (transactions denominated in a currency other than the entity's functional currency) are included in the consolidated statement of operations. These gains totaled approximately $5.0 million for the year ended December 31, 2004, and were immaterial for the years ended December 31, 2003 and 2002.

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 typically 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 and, to a lesser extent, purchasers of LPG. There was a nominal amount due from related parties at December 31, 2004 and no amounts due from related parties at December 31, 2003. 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 to us in the form of standby letters of credit, advance cash payments or "parental" guarantees. At December 31, 2004, we had received approximately $20.3 million of advance cash payments and prepayments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and assess whether our allowance for doubtful trade accounts receivable is adequate. Actual balances are not applied against the reserve until all collection efforts have been exhausted. At December 31, 2004 and 2003, substantially all of our net accounts receivable classified as current were less than 60 days past their scheduled invoice date, and our allowance for doubtful accounts receivable (the entire balance of which is classified as current) totaled $0.6 million and $0.2 million, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, there is no assurance that actual amounts will not vary significantly from estimated amounts. Following is a reconciliation of the changes in our allowance for doubtful accounts balances (in millions):

	December 31,		
	2004	2003	2002
Balance at beginning of year	$ 0.2	$ 8.1	$ 8.0
Applied to accounts receivable balances	—	(8.3)	—
Increase in reserve charged to expense	0.4	0.4	0.1
Balance at end of year	$ 0.6	$ 0.2	$ 8.1

Inventory and Pipeline Linefill

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars that is valued at the lower of cost or market, with cost determined using an average cost method. During the fourth quarter of 2004, we recorded a $2.0 million noncash charge related to the writedown of our LPG inventory. Linefill and minimum working inventory requirements are recorded at historical cost and consist of crude oil and LPG used to pack an operated pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location, as well as the minimum amount of crude oil necessary to operate our storage and terminalling facilities.

Linefill and minimum working inventory requirements in third party assets are included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory," at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is reflected as a separate line item within other assets on the consolidated balance sheet.

At December 31, 2004 and 2003, inventory and linefill consisted of:

	December 31, 2004							December 31, 2003				
	Barrels		Dollars		Dollar/ barrel		Barrels		Dollars		Dollar/ barrel
	(Barrels in thousands and dollars in millions)										
Inventory											
Crude oil	8,716	$	396.2	$	45.46		1,676	$	50.6	$	30.19
LPG	2,857		100.1		35.04		2,243		53.8		23.99
Other	—		1.9		N/A		—		1.6		N/A
Inventory subtotal	11,573	$	498.2				3,919	$	106.0		
Inventory in third-party assets											
Crude oil	1,294	$	48.7		37.64		853	$	22.6		26.49
LPG	318		10.6		33.33		183		4.1		22.40
Inventory in third-party assets subtotal	1,612	$	59.3				1,036	$	26.7		
Linefill											
Crude oil linefill	6,015	$	168.4		28.00		3,767	$	95.9		25.46
Total	19,200	$	725.9				8,722	$	228.6		

Property and Equipment

Property and equipment, net is stated at cost and consisted of the following:

	December 31,			
	2004		2003	
	(in millions)			
Crude oil pipelines and facilities	$	1,605.3	$	1,114.5
Crude oil and LPG storage and terminal facilities		169.6		100.8
Trucking equipment and other		117.6		43.8
Office property and equipment		19.0		13.5
		1,911.5		1,272.6
Less accumulated depreciation		(183.9)		(121.6)
	$	1,727.6	$	1,151.0

Depreciation expense for each of the three years in the period ended December 31, 2004, was $63.3 million, $42.4 million and $30.2 million, respectively. Our policy is to depreciate property and equipment over estimated useful lives as follows:

- crude oil pipelines and facilities—30 to 40 years;
- crude oil and LPG storage and terminal facilities—30 to 40 years;
- trucking equipment and other—5 to 15 years; and
- office property and equipment—3 to 5 years

We calculate our depreciation and amortization using the straight-line method, based on estimated useful lives and salvage values of our assets. These estimates are based on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

In accordance with our capitalization policy, costs associated with acquisitions and improvements, including related interest costs, which expand our existing capacity are capitalized. For the years ended December 31, 2004, 2003 and 2002, capitalized interest was $0.5 million, $0.5 million and $0.8 million, respectively. In addition, costs required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives are capitalized and classified as maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

Asset Retirement Obligation

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. The adoption of this statement did not have a material impact on our financial position, results of operations or cash flows.

Some of our assets, primarily related to our pipeline operations segment, have obligations to perform remediation and, in some instances, removal activities when the asset is abandoned. However, the majority of these obligations are associated with active assets and the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. A small portion of these obligations relate to assets that are inactive and although the ultimate timing and cost to settle these obligations is not known with certainty, we can reasonably estimate the obligation. As such, we have estimated that the fair value of these obligations is approximately $2.5 million at December 31, 2004. For those obligations that are currently indeterminate, we will record asset retirement obligations in the period in which we can reasonably determine the settlement dates.

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," as amended. 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. In 2004, we recognized a charge of approximately $2.0 million associated with taking our pipeline in the Illinois Basin out of service. The impairment represents the remaining net book value of the idled pipeline system. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks.

Other Assets

Other assets consist of the following:

	December 31, 2004	December 31, 2003
	(in millions)	
Goodwill	$ 47.1	$ 39.4
Deposit on pending acquisition	11.9	15.8
Debt issue costs	15.5	12.1
Investment in affiliate	8.2	7.8
Fair value of derivative instruments	8.6	5.9
Intangible assets	2.7	2.6
Other	14.0	7.1
	108.0	90.7
Less accumulated amortization	(4.1)	(1.7)
	$ 103.9	$ 89.0

In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," 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, 2004, substantially all of our goodwill is allocated to our gathering, marketing, terminalling and storage operations ("GMT&S"). Since adoption of SFAS 142, the company has not recognized any impairment of goodwill.

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. Debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized costs of approximately $5.9 million and $5.1 million in 2004 and 2003, respectively. In addition, during 2004 we wrote off approximately $0.7 million of unamortized costs and approximately $1.7 million of fully amortized costs and the related accumulated amortization. During 2003, we wrote off comparable amounts totaling $3.3 million and $11.3 million, respectively.

Amortization of other assets for each of the three years in the period ended December 31, 2004, was $3.9 million, $4.4 million and $3.9 million, respectively.

Environmental Matters

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. We also record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

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 capitalize environmental liabilities assumed in business combinations based on the fair value of the environmental obligations caused by past operations of the acquired company.

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 basis 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 the years presented, these amounts were immaterial.

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.

Recent Accounting Pronouncements

In March 2004, the Emerging Issues Task Force issued Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two-Class Method under FASB Statement No. 128." EITF 03-06 addresses a number of questions regarding the computation of earnings per share by companies that have issued securities, other than common stock, that contractually entitle the holder to participate in dividends and earnings of the company when, and if, it declares dividends on its common stock. The issue also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF 03-06 was effective for fiscal periods beginning after March 31, 2004. There was no impact on earnings per limited partner unit in the periods presented because of the adoption of EITF 03-06. The adoption of EITF 03-06 may have an impact on earnings per limited partner unit in future periods if net income exceeds distributions or if other participating securities are issued.

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. 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"). 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 Other Comprehensive Income ("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 limited partner units during the period, including 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. The following table sets forth the computation of basic and diluted net income per limited partner unit for 2004, 2003 and 2002.

	Year ended December 31,		
	2004	2003	2002
Net income	$ 130,006	$ 59,448	$ 65,292
Less:			
Incentive distribution right	(8,286)	(4,884)	(3,137)
Subtotal	121,720	54,564	62,155
General partner 2% ownership	(2,434)	(1,091)	(1,243)
Numerator for basic earnings per limited partner unit:			
Net income available for limited partners	119,286	53,473	60,912
Effect of dilutive securities:			
Increase in general partner's incentive distribution-contingent equity issuance	—	(61)	—
Numerator for diluted earnings per limited partner unit	$ 119,286	$ 53,412	$ 60,912
Denominator:			
Denominator for basic earnings per limited partner unit—weighted average number of limited partner units	63,277	52,743	45,546
Effect of dilutive securities:			
Contingent equity issuance	—	657	—
Denominator for diluted earnings per limited partner unit—weighted average number of limited partner units	63,277	53,400	45,546
Basic net income per limited partner unit	$ 1.89	$ 1.01	$ 1.34
Diluted net income per limited partner unit	$ 1.89	$ 1.00	$ 1.34

Note 3—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

Link Energy LLC

On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition-related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allow us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions. The results of operations and assets and liabilities from this acquisition (the "Link acquisition") have been included in our consolidated financial statements and in both our pipeline operations and gathering, marketing, terminalling and storage operations segments since April 1, 2004.

The purchase price was allocated as follows and includes goodwill primarily related to Link's gathering and marketing business (in millions):

Cash paid for acquisition(1)	$	268.0
Fair value of net liabilities assumed:		
Accounts receivable(2)		409.4
Other current assets		1.8
Accounts payable and accrued liabilities(2)		(459.6)
Other current liabilities		(8.5)
Other long-term liabilities		(7.4)
Total net liabilities assumed		(64.3)
Total purchase price	$	332.3
Purchase price allocation		
Property and equipment	$	260.2
Inventory		3.4
Linefill		55.4
Inventory in third party assets		8.1
Goodwill		5.0
Other long term assets		0.2
Total	$	332.3

(1) Cash paid does not include the subsequent payment of various transaction and other acquisition related costs.

(2) Accounts receivable and accounts payable are gross and do not reflect the adjustment of approximately $250 million to net settle, based on contractual agreements with our counterparties.

The total purchase price includes (i) approximately $9.4 million in transaction costs, (ii) approximately $7.4 million related to a plan to involuntarily terminate and relocate employees in conjunction with the acquisition, and (iii) approximately $11.0 million related to costs to terminate a contract assumed in the acquisition. These activities are substantially complete and the majority of the related costs have been incurred as of December 31, 2004. In addition, we anticipate making capital expenditures of approximately $28.0 million ($18.0 million in 2005) to upgrade certain of the assets and comply with certain regulatory requirements.

The acquisition was initially funded with cash on hand, borrowings under our existing revolving credit facilities and under a new $200 million, 364-day credit facility. In connection with the acquisition, on April 15, 2004, we completed the private placement of 3,245,700 Class C common units to a group of institutional investors. During the third quarter of 2004, we completed a public offering of common units and the sale of an aggregate of $350 million of senior notes. A portion of the proceeds from these transactions was used to retire the $200 million, 364-day credit facility.

In connection with the Link purchase, both PAA and Link completed all necessary filings required under the Hart-Scott-Rodino Act, and the required 30-day waiting period expired on March 24, 2004 without any inquiry or request for additional information from the U.S. Department of Justice or the Federal Trade Commission (the "FTC"). On April 2, 2004, the Office of the Attorney General of Texas (the "Texas AG") delivered written notice to us that it was investigating the possibility that the acquisition of Link's assets might reduce competition in one or more markets within the petroleum products industry in the State of Texas. Such investigation was coordinated with the FTC, consistent with federal-state protocols for conducting joint merger investigations. We cooperated fully with the antitrust enforcement authorities, including the provision of information at the request of the Texas AG Antitrust Division. In late 2004, we were informed by the Texas AG Antitrust Division and subsequently by the FTC that they were closing their investigation and do not have any current intentions to pursue any additional course of action with respect to these assets.

Capline and Capwood Pipeline Systems

In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.0 million in cash (including a $15.8 million deposit paid in December 2003) and approximately $0.5 million of transaction and other costs. In December 2003, subsequent to the announcement of the acquisition and in anticipation of closing, we issued approximately 2.8 million common units for net proceeds of approximately $88.4 million, after paying approximately $4.1 million of transaction costs. The proceeds from this issuance were used to pay down our revolving credit facility. At closing, the cash portion of this acquisition was funded from cash on hand and borrowings under our revolving credit facility.

The principal assets of these entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The results of operations and assets from this acquisition (the "Capline acquisition") have been included in our consolidated financial statements and in our pipeline operations segment since

March 1, 2004. These pipelines provide one of the primary transportation routes for crude oil shipped into the Midwestern U.S., and delivered to several refineries and other pipelines.

The purchase price was allocated as follows (in millions):

Crude oil pipelines and facilities	$	151.4
Crude oil storage and terminal facilities		5.7
Land		1.3
Office equipment and other		0.1
Total	$	158.5

Pro Forma Data

The following unaudited pro forma data is presented to show pro forma revenues, income before cumulative effect of change in accounting principle, net income, basic and diluted income before cumulative effect of accounting change per limited partner unit and basic and diluted net income per limited partner unit for the Partnership as if the Capline and Link acquisitions had occurred as of the beginning of the periods reported:

	Year Ended December 31,			
	2004		2003	
	(unaudited) (in millions, except per unit amounts)			
Revenues	$	21,023.4	$	12,807.5
Income before cumulative effect of change in accounting principle(1)	$	115.9	$	110.4
Net income(2)	$	112.8	$	106.4
Basic income before cumulative effect of change in accounting principle per limited partner unit(1)	$	1.77	$	1.97
Diluted income before cumulative effect of change in accounting principle per limited partner unit(1)	$	1.77	$	1.94
Basic net income per limited partner unit(2)	$	1.72	$	1.90
Diluted net income per limited partner unit(2)	$	1.72	$	1.87

(1) Includes a net gain in the 2003 period of approximately $67.5 million related to Link's predecessor company's reorganization, discharge of debt and fresh start adjustments.

(2) The 2003 period includes the amounts described in note (1) above as well as a loss of approximately $4.0 million related to Link's predecessor company's cumulative effect of change in accounting principle.

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 9.0 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.

Other Acquisitions

2004 Acquisitions

During 2004, in addition to the Link and Capline acquisitions, we completed several other acquisitions for aggregate consideration totaling $58.7 million including transaction costs. These acquisitions include crude oil mainline and gathering pipelines and propane storage facilities. The aggregate purchase price was allocated to property and equipment.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration totaling approximately $159.5 million. The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. The aggregate purchase price was allocated as follows (in million):

Crude oil pipelines and facilities	$	138.0
Crude oil and LPG storage facilities		7.3
Trucking equipment and other		7.8
Office property and equipment		1.2
Pipeline Linefill		4.7
Goodwill		0.5
	$	159.5

2002 Acquisitions

During 2002, in addition to the Shell acquisition, we completed two acquisitions for aggregate consideration totaling approximately $15.9 million including transaction costs. These acquisitions include crude oil pipeline, gathering and marketing assets and a 22% equity interest in a pipeline company. With the exception of $1.3 million that was allocated to goodwill, the aggregate purchase price was allocated to property and equipment.

Note 4—Asset Dispositions

Shutdown and Sale of Rancho Pipeline System

We acquired an interest in the Rancho Pipeline System from Shell in August 2002. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminated in March 2003. Upon termination, the agreement required the owners to take the pipeline system, in which we owned an approximate 50% interest, out of service. Accordingly, we notified our shippers and did not accept nominations for movements after February 28, 2003. This shutdown was contemplated at the time of the acquisition and was accounted for under purchase accounting in accordance with SFAS No. 141 "Business Combinations." The pipeline was shut down on March 1, 2003 and a purge of the crude oil linefill was completed in April 2003. In June 2003, we completed transactions whereby we transferred our ownership interest in approximately 241 miles of the total 458 miles of the pipeline in exchange for $4.0 million and approximately 500,000 barrels of crude oil tankage in West Texas. In August 2004, we sold our interest in the remaining portion of the system for approximately $0.9 million, including the assumption of all liabilities typically associated with pipelines of this type. We recognized a gain of approximately $0.6 million on this transaction.

Other Dispositions

During 2004, 2003 and 2002, we sold various other property and equipment for proceeds totaling approximately $3.0 million, $8.5 million and $1.4 million, respectively. Gains of approximately $0.6 million were recognized in both 2004 (including the gain on the sale of the Rancho Pipeline System) and 2003, respectively, and no gain or loss was recognized in 2002.

Note 5—Debt

Debt consists of the following:

	December 31,	
	2004	2003
	(in millions)	
Short-term debt:		
Senior secured hedged inventory borrowing facility bearing interest at a rate of 3.0% and 1.9% at December 31, 2004 and December 31, 2003, respectively	$ 80.4	$ 100.5
Working capital borrowings, bearing interest at a rate of 3.7% and 4.0% at December 31, 2004 and December 31, 2003, respectively[(1)]	88.2	25.3
Other	6.9	1.5
Total short-term debt	175.5	127.3
Long-term debt:		
Senior unsecured revolving credit facility, bearing interest at 3.5% at December 31, 2004[(1)]	$ 143.6	$ —
Senior unsecured $170 million Canadian revolving credit facility, bearing interest at a rate of 2.2% at December 31, 2003	—	70.0
4.75% senior notes due August 2009, net of unamortized discount of $0.7 million at December 31, 2004	174.3	—
7.75% senior notes due October 2012, net of unamortized discount of $0.3 million and $0.3 million at December 31, 2004 and December 31, 2003, respectively	199.7	199.7
5.63% senior notes due December 2013, net of unamortized discount of $0.6 million and $0.7 million at December 31, 2004 and December 31, 2003, respectively	249.4	249.3
5.88% senior notes due August 2016, net of unamortized discount of $1.1 million at December 31, 2004	173.9	—
Other	8.1	—
Total long-term debt[(1)]	949.0	519.0
Total debt	$ 1,124.5	$ 646.3

(1) At December 31, 2004 and 2003, we have classified $88.2 million and $25.3 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings under this facility and primarily are for hedged LPG inventory and New York Mercantile Exchange ("NYMEX") margin deposits and must be repaid within one year.

Credit Facilities

In November 2004, we entered into a new $750 million, five-year senior unsecured credit facility, which contains a sub-facility for Canadian borrowings of up to $300 million. The new credit facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facilities. This facility can be expanded to $1 billion. At December 31, 2004, approximately $231.8 million was outstanding under this facility (including $88.2 million classified as short-term).

Also in the fourth quarter of 2004, we amended and renewed our senior secured hedged inventory facility; increasing the facility to $425 million, with the ability to further increase the facility in the future by an incremental $75 million. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. This facility expires in November 2005.

Senior Notes

During August 2004, we completed the sale of $175 million of 4.75% Senior Notes due 2009 and $175 million of 5.88% Senior Notes due 2016. The 4.75% notes were sold at 99.551% of face value and the 5.88% notes were sold at 99.345% of face value. Interest payments are due on February 15 and August 15 of each year.

During December 2003, we completed the sale of $250 million of 5.625% senior notes due in December 2013. The notes were issued at a discount of $0.7 million, resulting in an effective interest rate of 5.66%. Interest payments are due on June 15 and December 15 of each year.

During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012. The notes were issued 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.

In each instance, the notes were co-issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor.

Covenants and Compliance

Our credit agreements and the indentures governing the senior notes contain cross default provisions. Our credit agreements 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 if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions;
- sell substantially all of our assets or enter into a merger or consolidation.

Our credit facility treats a change of control as an event of default and also requires us to maintain:

- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt coverage ratio which will not be greater than 4.75 to 1.0 on all outstanding debt and 5.25 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures.

Letters of Credit

As is customary in our industry, and in connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our credit facility, and 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, 2004 and 2003, we had outstanding letters of credit of approximately $98.0 million and $57.9 million, respectively. In addition to changes in the level of activity and other factors, the amount of letters of credit outstanding varies based on NYMEX crude oil prices, which were $43.34 per barrel and $32.52 per barrel at December 31, 2004 and 2003, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2004, was approximately 8 years and the aggregate maturities for the for the next five years are as follows:

Calendar Year	Payment
2005	$ —
2006	3.7
2007	3.6
2008	0.8
2009	318.6
Thereafter	625.0
Total[(1)]	951.7

(1) Reflects aggregate unamortized discount of $2.7 million on our various senior notes.

Note 6—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2004 consists of 67,293,108 common units, including 1,307,190 Class B common units and 3,245,700 Class C common units, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving affect to the general partner interest), and a 2% general partner interest.

Class B and Class C Common Units

The Class B common units and Class C common units were *pari passu* with common units with respect to quarterly distributions. In accordance with a common unitholder vote at a special meeting on January 20, 2005, each Class B common unit and Class C common unit became convertible into one common unit upon request of the holder. In February 2005, all of the Class B and Class C common units converted into common units.

Subordinated Units and Conversion

Pursuant to the terms of our Partnership Agreement and having satisfied the financial tests contained therein, in November 2003, 25% of the subordinated units converted to common units on a one-for-one basis. In February 2004, all of the remaining subordinated units converted to common units on a one-for-one basis.

The subordinated units have a debit balance in Partners' Capital of approximately $39.9 million at December 31, 2003. The debit balance is the result of several different factors including: (i) a low initial capital balance in connection with the formation of the Partnership as a result of a low carry-over book basis in the assets contributed to the Partnership at the date of formation, (ii) a significant net loss in 1999 and (iii) distributions to unitholders that have exceeded net income allocated to unitholders each period. Additionally, the capital balances of the common unitholders and the General Partner have increased periodically as additional units have been sold and as the General Partner has made additional capital contributions associated with those offerings. The subordinated unitholders are not required to make any additional contributions associated with those offerings of common units. No additional subordinated units were issued after the initial issuance.

General Partner Incentive Distributions

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, referred to as our minimum quarterly distributions ("MQD"), 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 (referred to as "incentive distributions"). Cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2004		2003		2002	
	Distribution(1)	Excess over MQD	Distribution(1)	Excess over MQD	Distribution(1)	Excess over MQD
First Quarter	$ 0.5625	$ 0.1125	$ 0.5375	$ 0.0875	$ 0.5125	$ 0.0625
Second Quarter	$ 0.5625	$ 0.1125	$ 0.5500	$ 0.1000	$ 0.5250	$ 0.0750
Third Quarter	$ 0.5775	$ 0.1275	$ 0.5500	$ 0.1000	$ 0.5375	$ 0.0875
Fourth Quarter	$ 0.6000	$ 0.1500	$ 0.5500	$ 0.1000	$ 0.5375	$ 0.0875

(1) Distributions represent those declared and paid in the applicable period.

Distributions

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. Total cash distributions made were as follows:

Year	Common Units	Subordinated Units	GP 2%	GP Incentive	Total	Distribution per unit
	(in millions, except per unit amounts)					
2004	$ 142.9	$ 4.2	$ 3.0	$ 8.3	$ 158.4	$ 2.30
2003	$ 92.7	$ 21.9	$ 2.3	$ 4.9	$ 121.8	$ 2.19
2002	$ 73.6	$ 21.1	$ 2.0	$ 3.1	$ 99.8	$ 2.11

On January 25, 2005, we declared a cash distribution of $0.6125 per unit on our outstanding common units, Class B common units and Class C common units. The distribution was paid on February 14, 2005, to unitholders of record on February 4, 2005, for the period October 1, 2004, through December 31, 2004. The total distribution paid was approximately $45.0 million, with approximately $41.2 million paid to our common unitholders and $0.8 million and $3.0 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Equity Offerings

During the three years ended December 31, 2004, we completed the following public equity offerings of our common units:

Period	Units	Gross Unit Price	Proceeds from Sale	GP Contribution	Costs	Net Proceeds
		(in millions, except per unit amounts)				
July/August 2004	4,968,000	$ 33.25	$ 165.2	$ 3.4	$ 7.7	$ 160.9
December 2003	2,840,800	$ 31.94	$ 90.7	$ 1.8	$ 4.1	$ 88.4
September 2003	3,250,000	$ 30.91	$ 100.5	$ 2.1	$ 4.6	$ 98.0
March 2003	2,645,000	$ 24.80	$ 65.6	$ 1.3	$ 3.0	$ 63.9
August 2002	6,325,000	$ 23.50	$ 148.6	$ 3.0	$ 6.6	$ 145.0

Private Placement of Class C Common Units

In connection with the Link acquisition, on April 15, 2004 we issued 3,245,700 Class C common units for $30.81 per unit in a private placement to a group of institutional investors consisting of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital Advisors. Affiliates of both Kayne Anderson Capital Advisors and Vulcan Capital own interests in our general partner. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, were approximately $101 million, and were used to reduce the balance outstanding under our revolving credit facilities. The Class C common units were unlisted securities that are *pari passu* in voting and distribution rights with the Partnership's publicly traded common units. The Class C common units were similar in most respects to the Partnership's Class B common units. Both classes became convertible on a one-for-one basis into common units upon approval by the holders of a majority of the common units at a special meeting of our unitholders held on January 20, 2005. All of the Class B common units and Class C common units converted in February 2005.

Payment of Deferred Acquisition Price

In connection with the CANPET acquisition in July 2001, $26.5 million Canadian of the purchase price, payable in common units or cash at our option, was deferred subject to various performance objectives being met. These objectives were met as of December 31, 2003 and an increase to goodwill for this liability was recorded as of that date. The liability was satisfied on April 30, 2004 with the issuance of approximately 385,000 common units and the payment of $6.5 million in cash. The number of common units issued in satisfaction of the deferred payment was based upon $34.02 per share, the average trading price of our common units for the ten-day trading period prior to the payment date, and a Canadian dollar to U.S. dollar exchange rate of 1.35 to 1, the average noon-day exchange rate for the ten-day trading period prior to the payment date. In addition, an incremental $3.7 million in cash was paid for the distributions that would have been paid on the common units had they been outstanding since the effective date of the acquisition.

Note 7—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.

Summary of Financial Impact

The following is a summary of the financial impact of the derivative instruments and hedging activities discussed below. The December 31, 2004, balance sheet includes assets of $63.9 million ($55.2 million current), liabilities of $29.5 million ($18.9 million current) and unrealized net gains deferred to Other Comprehensive Income ("OCI") of $25.9 million. Total derivative activities for the year ended December 31, 2004, generated a gain of $35.1 million. This gain includes (i) derivatives that do not qualify for hedge accounting (a gain of approximately $0.9 million), (ii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items (a gain of approximately $0.1 million), and (iii) gains and losses recognized in earnings for all hedges settled during the period (a net gain of approximately $34.1 million). The majority of these gains are related to our commodity price risk hedging activities that are offset by physical transactions, as discussed below.

As of December 31, 2004, the total amount of deferred net gains 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 year ended December 31, 2004, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring. Of the $25.9 million net gain deferred in OCI at December 31, 2004, a net gain of $34.7 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2009 for amounts related to our commodity price risk hedging). Since a portion of these amounts is 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.

The following sections discuss our risk management activities in the indicated categories.

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 we use consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. In accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended, these derivative instruments are recognized in the balance sheet or earnings at their fair values. The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into OCI and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133. Physical transactions that are derivatives and are ineligible, or become ineligible, for the normal purchase and sale treatment (e.g. due to changes in settlement provisions) are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Controlled Trading Program

Although we seek to maintain a position that is substantially balanced within our crude oil lease purchase activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. 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 an aggregate of 500,000 barrels of crude oil. 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.

Interest Rate Risk Hedging

At December 31, 2004, we have no open interest rate hedging instruments. However, there are approximately $6.1 million deferred in OCI that relates to cash flow hedge instruments that were terminated and cash settled ($1.4 million related to an instrument settled in 2004 and $4.7 million related to instruments settled in 2003) that relate to debt agreements refinanced in 2004 and 2003, respectively. The deferred loss related to these instruments is being amortized into interest expense over the original terms of the terminated instruments (approximately $2.9 million over the next two years and the remaining $3.2 million over approximately ten years). Approximately $1.5 million related to the terminated instruments were reclassified into interest expense during 2004. In addition, earnings for 2004 include a loss of approximately $0.7 million that was reclassified out of OCI related to an instrument that matured in March 2004.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars and, at times, a portion of our debt is denominated in Canadian dollars, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts and cross currency swaps. Neither the forward exchange contracts nor the cross currency swaps qualify for hedge accounting in accordance with SFAS 133.

At December 31, 2004, we had forward exchange contracts that allow us to exchange Canadian dollars for U.S. dollars, quarterly, at set exchange rates as detailed below:

	Canadian Dollars	US Dollars	Rate
	($ in millions)		
2005	$3.0	$2.3	1.33 to 1
2006	$2.0	$1.5	1.32 to 1

In addition, at December 31, 2004, we also had cross currency swap contracts for an aggregate notional principal amount of $21.0 million, effectively converting this amount of our U.S. dollar denominated debt to $32.5 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount will reduce by $2.0 million U.S. in May 2005 and has a final maturity in May 2006 of $19.0 million U.S. At December 31, 2004, $9.9 million of our long-term debt was denominated in Canadian dollars ($11.9 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.20 to 1). All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

Fair Value of Financial Instruments

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

	December 31,			
	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
NYMEX futures	$42.3	$42.3	$7.5	$7.5
Options and swaps	$(2.8)	$(2.8)	$(3.3)	$(3.3)
Forward exchange contracts	$(1.5)	$(1.5)	$(0.4)	$(0.4)
Cross currency swaps	$(6.3)	$(6.3)	$(4.8)	$(4.8)
Interest rate swaps	$—	$—	$(0.4)	$(0.4)
Short and long-term debt under credit facilities	$231.8	$231.8	$95.3	$95.3
Borrowings under senior secured hedged inventory facility	$80.4	$80.4	$100.5	$100.5
Senior notes	$797.3	$848.0	$449.0	$482.9

As of December 31, 2004 and 2003, 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 and senior secured hedged inventory facility approximate fair value primarily because the interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market. The interest rate on our senior notes (7.75%, 5.88%, 5.63%, and 4.75%) 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 liquidation values. We also have over-the-counter option and swap contracts for which fair values are estimated based on 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 8—Major Customers and Concentration of Credit Risk

Marathon Ashland Petroleum ("MAP") accounted for 10%, 12% and 10% of our revenues for each of the three years in the period ended December 31, 2004. BP Oil Supply also accounted for 10% of our revenues for the year ended December 31, 2004. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of the revenues from MAP and BP Oil Supply pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of these customers 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.

Note 9—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. Total costs reimbursed by us to our general partner for the years ended December 31, 2004, 2003 and 2002 were approximately $151.0 million, $88.1 million and $70.8 million, respectively.

Crude Oil Marketing Agreement

As of December 31, 2004, Vulcan Energy, through its wholly-owned subsidiary Plains Resources, owned an effective 44% of our general partner interest, as well as approximately 18.3% of our outstanding limited partner units. We are the exclusive marketer/purchaser for all of Plains Resources' and its subsidiaries' equity crude oil production. We have a marketing agreement with Plains Resources (the "Marketing Agreement") whereby we will purchase for resale at market prices the majority 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, 2004, 2003 and 2002, we paid Plains Resources approximately $28.3 million, $25.7 million and $247.7 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production, and recognized margins of approximately $0.1 million, $0.2 million and $1.8 million from the marketing fee for the same periods, respectively. In our opinion, these purchases were made at prevailing market prices. In connection with the separation of Plains Resources and one of its subsidiaries, discussed below, Plains Resources divested the bulk of its producing properties. As a result, we do not anticipate the marketing arrangement with Plains Resources to be material to our operating results in the future. As currently in effect, the Marketing Agreement will terminate upon a "change of control" of Plains Resources or our general partner. The recent purchase of Plains Resources by Vulcan Energy would have constituted a change of control under the Marketing Agreement. In July 2004, we amended and restated the Marketing Agreement to exclude the Vulcan transaction from the change of control provisions.

In December 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production Company ("PXP") to its shareholders. PXP is a successor participant to the Marketing Agreement. For the years ended December 31, 2004 and 2003, we paid PXP approximately $328.3 million and $277.9 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production and recognized margins of approximately $1.4 and $1.7 million, respectively, from the marketing fee. In our opinion, these purchases were made at prevailing market prices. We are also party to 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. ("Tosco") 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. In July 2004, we amended and restated the Marketing Agreement to, among other things, reflect the change in parties as a result of the spin-off. We sell PXP's crude under sales contracts that range from one year to four years in length. In October 2004, we further amended the PXP Marketing Agreement to exclude any newly acquired properties and to adjust the marketing fee to $0.15 per barrel for any new contracts entered into after January 1, 2005.

Due to Related Parties

The balance of amounts due to related parties at December 31, 2004 and 2003 was $32.9 million and $27.0 million, respectively, and was primarily related to crude oil purchased by us but not yet paid as of December 31 of each year.

Performance Option Plan

In connection with the transfer of a majority of our general partner interest in 2001, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common 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 391,000 units have been granted. These 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 second level was reached, and an additional 25% of the options vested, in 2004. The options will vest in their entirety immediately upon a change in control (as defined in the grant agreements). The exercise price under the options was $22 per unit at the time of grant, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of December 31, 2004, the exercise price was $15.91 per unit. The terms of future grants may differ from the existing grants. Because the 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. At December 31, 2004 approximately 388,000 units were outstanding.

Benefit Plan

Our 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 years ended December 31, 2004, 2003 and 2002, the defined contribution plan matching expense was approximately $4.0 million, $2.6 million and $2.1 million, respectively. Similarly, PMC (Nova Scotia) Company maintains a group Registered Savings Plan and a Non Registered Employee Savings Plan for our Canadian employees. For the years ended December 31, 2004, 2003 and 2002, these plans had expense of approximately $1.0 million, $0.7 million and $0.4 million, respectively.

Note 10—Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the 1998 LTIP include phantom units and unit options. The 1998 LTIP currently permits the grant of phantom 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 has the right to alter or amend the 1998 LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, 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.

A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). As of December 31, 2004, aggregate outstanding grants of approximately 134,000 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.

Common units to be delivered upon the vesting of grants 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 and any other costs incurred in settling obligations under the 1998 LTIP. In addition, the Partnership may issue up to 975,000 new 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 phantom units, the total number of common units outstanding will increase. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights ("DERs") with respect to phantom units. A DER entitles the grantee to a cash payment, either while the award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the award is outstanding. There are no tandem equivalent distribution rights outstanding at this time under the 1998 LTIP.

Other than grants to directors, none of the phantom units vested until November 2003. Since that time, approximately 927,000 phantom units have vested. Including grants to directors, approximately 418,000 units have been purchased and delivered or issued in satisfaction of vesting, after payment of cash-equivalents and netting for taxes. Under generally accepted accounting principles, we are required to recognize expense when it is considered probable that phantom unit grants under our 1998 LTIP will vest. As a result, we recognized an expense of approximately $7.9 million and $28.8 million for the years ended December 31, 2004 and 2003, respectively.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon vesting and delivery of the common units.

Our 1998 LTIP currently permits the grant of options to purchase common units. No unit option grants have been made under the 1998 LTIP 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.

In January 2005, our unitholders approved the 2005 Long-Term Incentive Plan (the "2005 LTIP"). The 2005 LTIP provides for awards to our employees and directors. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the Compensation Committee (each an "Award"). Up to 3,000,000 units may be issued in satisfaction of Awards. Certain Awards may also include DERs in the discretion of the Compensation Committee. Our general partner will be entitled to reimbursement by us for any costs incurred in settling obligations under the 2005 LTIP. Certain of these Awards could be considered a common stock equivalent and thus be dilutive to our earnings per unit from the time of their date of grant. In February 2005, our Board of Directors and Compensation Committee approved grants of approximately 1,900,000 phantom units (a substantial number of which include DERs) under the 2005 LTIP.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon vesting and delivery of the common units.

Note 11—Commitments and Contingencies

We lease certain real property, equipment and operating facilities under various operating and capital 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, 2004, are summarized below (in millions):

2005	$17.8
2006	$14.0
2007	$10.9
2008	$6.3
2009	$5.2
Thereafter	$13.7

Expenditures related to leases for 2004, 2003 and 2002 were $20.1 million, $13.4 million and $9.7 million, respectively.

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. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 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 received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, asserted breach of fiduciary duty and breach of contract claims against us, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. The complaint sought to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. This lawsuit has been settled in principle. The court has approved the settlement and, assuming no appeals are filed, the settlement will become final in March 2005.

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.

Note 12—Environmental Remediation

We currently own or lease properties where hazardous liquids, including hydrocarbons, are being or have been handled. As such, we could be required to remove or remediate hazardous liquids or associated generated wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In addition, we have entered into indemnification agreements with various counterparties in conjunction with several of our acquisitions. Allocation of environmental liability is an issue negotiated in connection with each of our acquisition transactions. In each case, we make an assessment of potential environmental exposure based on available information. Based on that assessment and relevant economic and risk factors, we determine whether to negotiate an indemnity, what the terms of any indemnity should be (for example, minimum thresholds or caps on exposure) and whether to obtain insurance, if available. In some cases, we have received contractual protections in the form of environmental indemnifications from several predecessor operators for properties acquired by us that are contaminated as a result of historical operations. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply and have term and total dollar limits.

The acquisitions we completed in 2003 and 2004 include a variety of provisions dealing with the allocation of responsibility for environmental costs that range from no or limited indemnities from the sellers to indemnification from sellers with defined limitations on their maximum exposure. We have not obtained insurance for any of the conditions related to our 2003 acquisitions, and only in limited circumstances for our 2004 acquisitions.

For instance, in connection with the Link acquisition, we identified a number of environmental liabilities for which we received a purchase price reduction from Link. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico ("TNM") pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we will bear $11 million of the first $20 million of pre-May 1999 environmental issues. We will also bear the first $25,000 per site for new sites which were not identified at the time we entered into the agreement (capped at 100 sites). TNM will pay all costs in excess of $20 million (excluding the deductible for new sites). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). We recorded a reserve for environmental liabilities of approximately $17.0 million in connection with the Link acquisition.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, Shell purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a $100,000 deductible per site, an aggregate coverage limit of $70 million, and expires in 2012. Shell has recently made a claim against the policy; however, we do not believe that the claim will substantially reduce our coverage under the policy.

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which occurred prior to the date of the closing of the acquisition. This indemnity applied to claims that exceeded $25,000 individually and $1.0 million in the aggregate. For the indemnity to apply, we were required to assert any claims on or before May 15, 2003. In conjunction with the expiration of this indemnity, we reached agreement with respect to MAP's remaining indemnity obligations. Under the terms of this agreement, MAP will continue to remain obligated for liabilities associated with two Superfund sites at which it is alleged that Scurlock Permian deposited waste oils. In addition, MAP paid us $4.6 million cash as satisfaction of its obligations with respect to other sites. During 2002, we had reassessed previous investigations and completed environmental studies related to environmental conditions associated with our 1999 acquisitions. As a result of that reassessment, we established an additional reserve of $1.2 million.

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

At December 31, 2004, our reserve for environmental liabilities totaled approximately $19.8 million (approximately $12.7 million of this reserve is related to liabilities assumed as part of the Link acquisition). Approximately $9.3 million of our environmental reserve is classified as current and $10.5 million is classified as long-term. At December 31, 2004, we have recorded receivables totaling approximately $6.3 million for amounts recoverable under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. We believe that this reserve is adequate, and in conjunction with our indemnification arrangements, should prevent remediation costs from having a material adverse effect on our financial condition, results of operations, or cash flows. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, no assurances can be made that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations, or cash flows.

Note 13—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total(1)
			(in thousands, except per unit data)		
2004					
Revenues(3)	$ 3,804.6	$ 5,131.7	$ 5,867.0	$ 6,172.1	$ 20,975.5
Gross margin	59.7	64.8	74.0	65.7	264.2
Operating income	40.5	45.2	55.1	39.2	180.0
Income before cumulative effect of change in accounting principle	31.0	35.7	41.7	24.7	133.1
Net income	27.9	35.7	41.7	24.7	130.0
Basic and diluted income per limited partner unit before cumulative effect of change in accounting principle	0.49	0.54	0.59	0.32	1.94
Basic and diluted net income per limited partner unit	0.44	0.54	0.59	0.32	1.89
Cash distributions per common unit(2)	$ 0.563	$ 0.563	$ 0.578	$ 0.600	$ 2.30
2003					
Revenues(3)	$ 3,281.9	$ 2,709.2	$ 3,053.7	$ 3,545.0	$ 12,589.8
Gross margin	46.7	44.0	38.7	41.2	170.6
Operating income	33.6	31.9	21.0	11.6	98.2
Net income (loss)	24.4	23.4	11.9	(0.2)	59.4
Basic net income (loss) per limited partner unit	0.46	0.42	0.20	(0.03)	1.01
Diluted net income (loss) per limited partner unit	0.46	0.42	0.20	(0.03)	1.00
Cash distributions per common unit(2)	$ 0.538	$ 0.550	$ 0.550	$ 0.550	$ 2.19

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

(2) Distributions represent those declared and paid in the applicable period.

(3) Includes buy/sell transactions, see Note 2.

Note 14—Operating Segments

Our operations consist of two operating segments: (i) pipeline operations ("Pipeline Operations") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. 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 results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use and lease less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs, and (iii) segment general and administrative expenses. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (note that each of the items in the following table excludes depreciation and amortization):

	Pipeline	GMT&S	Total
		(in millions)	
Twelve Months Ended December 31, 2004			
Revenues:			
External Customers (includes buy/sell revenues of $149.8, $11,247.0, and $11,396.8, respectively)	$ 752.9	$ 20,222.6	$ 20,975.5
Intersegment[(a)]	122.0	0.9	122.9
Total revenues of reportable segments	$ 874.9	$ 20,223.5	$ 21,098.4
Segment profit[(c)]	$ 157.2	$ 91.5	$ 248.7
Capital expenditures	$ 520.7	$ 131.5	$ 652.2
Total assets	$ 1,507.5	$ 1,652.9	$ 3,160.4
Non-cash SFAS 133 impact[(b)]	$ —	$ 1.0	$ 1.0
Maintenance capital	$ 8.3	$ 3.0	$ 11.3
Twelve Months Ended December 31, 2003			
Revenues:			
External Customers (includes buy/sell revenues of $166.2, $6,124.9, and $6,291.1, respectively)	$ 605.1	$ 11,984.7	$ 12,589.8
Intersegment[(a)]	53.5	0.9	54.4
Total revenues of reportable segments	$ 658.6	$ 11,985.6	$ 12,644.2
Segment profit[(c)]	$ 81.3	$ 63.1	$ 144.4
Capital expenditures	$ 211.9	$ 21.9	$ 233.8
Total assets	$ 1,221.0	$ 874.6	$ 2,095.6
Non-cash SFAS 133 impact[(b)]	$ —	$ 0.4	$ 0.4
Maintenance capital	$ 6.4	$ 1.2	$ 7.6
Twelve Months Ended December 31, 2002			
Revenues:			
External Customers (includes buy/sell revenues of $95.8, $4,140.8, and $4,236.7, respectively)	$ 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 profit[(c)]	$ 70.7	$ 58.9	$ 129.6
Capital expenditures	$ 341.9	$ 23.3	$ 365.2
Non-cash SFAS 133 impact[(b)]	$ —	$ 0.3	$ 0.3
Maintenance capital	$ 3.4	$ 2.6	$ 6.0

Table continued on following page

(a) Intersegment sales were conducted at arms length.

(b) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(c) The following table reconciles segment profit to consolidated income before cumulative effect of change in accounting principle (in millions):

	Year ended December 31,		
	2004	2003	2002
Segment profit	$ 248.7	$ 144.4	$ 129.6
Unallocated general and administrative expenses	—	—	(1.0)
Depreciation and amortization	(67.2)	(46.8)	(34.1)
Gain on sale of assets	0.6	0.6	—
Impairment loss	(2.0)	—	—
Interest expense	(46.7)	(35.2)	(29.1)
Interest income and other, net	(0.3)	(3.6)	(0.1)
Income before cumulative effect of change in accounting principle	$ 133.1	$ 59.4	$ 65.3

Geographic Data

We have operations in the United States and Canada. Set forth below are revenues and long lived assets attributable to these geographic areas (in millions):

	For the Year Ended December 31,		
Revenues	2004	2003	2002
United States (includes buy/sell revenues of $10,164.6, $5,621.6, and $3,715.5, respectively)	$ 17,499.5	$ 10,536.8	$ 6,941.7
Canada (includes buy/sell revenues of $1,232.2, $669.5, and $521.2, respectively)	3,476.0	2,053.0	1,442.5
	$ 20,975.5	$ 12,589.8	$ 8,384.2

	For the Year Ended December 31,	
Long-Lived Assets	2004	2003
United States	$ 1,670.8	$ 1,039.8
Canada	379.7	316.9
	$ 2,050.5	$ 1,356.7

Note 15—Subsequent Event

On February 25, 2005, we issued 575,000 common units to a subsidiary of Vulcan Energy Corporation. The sale price for the common units was $38.13 per unit resulting in net proceeds, including the general partner's proportionate capital contribution and expenses associated with the sale, of approximately $22.3 million. We intend to use the net proceeds from the private placement to fund a portion of our 2005 expansion capital program. Pending the incurrence of such expenditures, the net proceeds will be used to repay indebtedness under our revolving credit facilities.

EXHIBIT 10.20

PMC (Nova Scotia) Company Bonus Plan

1. Every fiscal quarter an amount equal to four percent (4%) of PMC's Quarterly Earnings, as hereinafter defined, shall be pooled (the "Quarterly Bonus Pool"). In the event that there is a loss in any quarter such amount shall be recouped before earnings in subsequent quarters are eligible for participation in the Quarterly Bonus Pool. Employees participating in the bonus plan shall be eligible to receive a bonus to be determined quarterly from the Quarterly Bonus Pool, the amount of which, if any, shall be in the sole and exclusive discretion of PMC's management committee.

2. Every year an amount equal to six percent (6%) of PMC's Annual Earnings, as hereinafter defined, shall be pooled (the "Annual Bonus Pool"). Employees participating in the bonus plan shall be eligible to receive a bonus to be determined annually from the Annual Bonus Pool, the amount of which shall be in the sole and exclusive discretion of PMC's management

3. (a) Quarterly Earnings shall equal EBITDA for such quarter less an administrative fee of $.02 Cdn. per outright purchased barrel during such quarter.

   (b) Annual Earnings shall equal EBITDA for such annual period less an administrative fee of $.02 Cdn per outright purchased barrel during such period.

   (c) For the purposes of this Schedule, "EBITDA" shall have the meaning given to it in Section 1.1 of this Agreement, except that "net of bonuses" shall be deleted.

   (d) The administrative fee referred to above shall not be increased for three years.

   (e) All payments made with respect to the Quarterly Bonus Pool and Annual Bonus Pool shall be paid three months in arrears.

4. For the year 2001, the Annual Bonus Pool shall related to the period from the Effective Time through December 31, 2001 and the first Quarterly Bonus Pool shall be for the month of March and thereafter the Quarterly Bonus Pool shall be attributable to calendar quarters. All employees of the Vendor hired by the Purchaser shall be eligible to be included in the 2001 Annual Bonus Pool and the first Quarterly Bonus Pool.

5. Except as otherwise approved by PMC's management committee, to qualify for participation in the Quarterly Bonus Pool or Annual Bonus Pool, the employee has to be actively employed by PMC for the period from the first day of the applicable bonus period through the date the Quarterly and/or Annual Bonus Pools are payable.

6. Nothing in this Plan shall interfere with or limit in any way the right of PMC to terminate any Employee's employment at any time, nor confer upon any Employee any right to continue in the employ of PMC. No award under this Plan shall constitute an employment agreement (or part of an employment agreement) with PMC or give rise to liability on the part of PMC for severance payments. The awards under this Plan are not intended to be treated as compensation for any purpose under any other PMC plan or benefit.

7. For Employees hired by PMLP then wherever PMC appears above, PMLP shall be substituted therein.

8. This Bonus Plan shall not be amended or modified by PMC or PMLP for a period of three years. Thereafter, the Bonus Plan may be amended or modified as determined by the general partner's board of directors.

9. Sales personnel whose primary compensation is commission (including consultants) may be excluded from the Annual Bonus Pool and the Quarterly Bonus Pool.

Exhibit 10.21

Quarterly bonus program summary

Certain officers and employees in our marketing group and business development group participate in a quarterly bonus arrangement based on EBITDA from our commercial activities during the quarter. Total participants include approximately 70-75 employees. The quarterly bonus pool for 2004 totaled approximately $4.3 million.

Exhibit 10.22

Director compensation summary

Each director of our general partner who is not an employee of our general partner is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Each non-employee director is currently paid an annual retainer fee of $45,000. 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 $30,000 annually, and the other members of the Audit Committee receive $15,000 annually. Mr. Petersen assigns any compensation he receives in his capacity as a director to EnCap Energy Capital Fund III, L.P. (EnCap III), which is controlled by EnCap Investments L.P., of which Mr. Petersen is a Managing Director. Mr. Capobianco assigns any compensation he receives in his capacity as a director to Vulcan Capital.

Except as described below, each non-employee director has received an LTIP award of 5000 units in the aggregate. These units vest annually in August in 25% increments, subject to an automatic re-grant of the amount vested, such that the director will always have outstanding an award of 5000 units. For Mr. Peterson and Mr. Capobianco, a cash equivalent payment will be made to EnCap III and Vulcan Capital, respectively, upon any vesting. The units vest in full upon the death or disability (as determined by the board) of the director. For any "independent" directors (as defined in the Third Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, as amended, and currently including Messrs. Goyanes, Smith and Symonds), the units will also vest full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the Board or is not reelected to the Board, unless such removal or failure to reelect is for "good cause," as defined in the letter granting the phantom units.

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-91141, 333-54118, 333-74920 and 333-122806) of Plains All American Pipeline, L.P. of our report dated March 2, 2005 relating to the consolidated financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2005

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EXHIBIT 31.1

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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2005

/s/ GREG L. ARMSTRONG

Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PLAINS ALL AMERICAN PIPELINE, L.P.

I, Phil 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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2005

/s/ PHIL KRAMER

Phil Kramer
Chief Financial Officer

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CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PLAINS ALL AMERICAN PIPELINE, L.P.

EXHIBIT 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. § 1350**

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-K for the period ending December 31, 2004 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ GREG L. ARMSTRONG

Name: Greg L. Armstrong
Date: March 2, 2005

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EXHIBIT 32.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. § 1350**

I, Phil Kramer, Chief Financial Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-K for the period ending December 31, 2004 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ PHIL KRAMER

Name: Phil Kramer
Date: March 2, 2005

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CERTIFICATION OF CHIEF FINANCIAL OFFICER OF PLAINS ALL AMERICAN PIPELINE, L.P. PURSUANT TO 18 U.S.C. § 1350