PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
March 01, 2007

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

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

OR

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

Commission file number 1-14569

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

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

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

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 þ No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer o

Indicate by check mark if the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

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 $2.7 billion on June 30, 2006, based on $43.67 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 20, 2007, there were outstanding 109,405,178 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K 2006 ANNUAL REPORT

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Certification of PFO Pursuant to Section 1350

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements identified by the words anticipate, believe, estimate, expect, plan, intend forecast, and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. 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:

our failure to successfully integrate the business operations of Pacific Energy Partners L.P. (Pacific) or our failure to successfully integrate any future acquisitions;

the failure to realize the anticipated cost savings, synergies and other benefits of the merger with Pacific;

the success of our risk management activities;

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 and trade counterparties;

abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;

failure to implement or capitalize on planned internal growth projects;

the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate, and other factors that could cause declines in volumes shipped on our pipelines by us and third party shippers;

fluctuations in refinery capacity in areas supplied by our mainlines, and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transmission throughput requirements;

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;

future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

unanticipated changes in crude oil market structure and volatility (or lack thereof);

the impact of current and future laws, rulings and governmental regulations;

the effects of competition;

continued creditworthiness of, and performance by, our counterparties;

interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

increased costs or lack of availability of insurance;

fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our Long-Term Incentive Plans;

the currency exchange rate of the Canadian dollar;

shortages or cost increases of power supplies, materials or labor;

weather interference with business operations or project construction;

risks related to the development and operation of natural gas storage facilities;

general economic, market or business conditions; and

other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risks Related to Our Business discussed in Item 1A. Risk Factors. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

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PART I

Items 1 and 2. *Business and Properties*

General

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in September 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K, the terms Partnership, Plains, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. and its sub unless the context indicates otherwise.

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas related petroleum products collectively as LPG. Through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan), we develop and operate natural gas storage facilities.

Prior to the fourth quarter of 2006, we managed our operations through two segments. Due to our growth, especially in the facilities portion of our business (most notably in conjunction with the Pacific acquisition), we have revised the manner in which we internally evaluate our segment performance and decide how to allocate resources to our segments. As a result, we now manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing.

Transportation Our transportation segment operations generally consist of fee-based activities associated with transporting volumes of crude oil and refined products on pipelines and gathering systems. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity, transportation fees, barrel exchanges and buy/sell arrangements.

As of December 31, 2006, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 20,000 miles of active pipelines and gathering systems;
- 30 million barrels of tank capacity used primarily to facilitate pipeline throughput; and
- 57 transport and storage barges and 30 transport tugs through our 50% interest in Settoon Towing, LLC (Settoon Towing).

We also include in this segment our equity earnings from our investments in the Butte Pipe Line Company (Butte) and Frontier Pipeline Company (Frontier) pipeline systems, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

Facilities Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

As of December 31, 2006, we owned and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 30 million barrels of active, above-ground terminalling and storage facilities;
- approximately 1.3 million barrels of active, underground terminalling and storage facilities; and
- a fractionation plant in Canada with a processing capacity of 4,400 barrels per day, and a fractionation and isomerization facility in California with an aggregate processing capacity of 22,000 barrels per day.

At year-end 2006, we were in the process of constructing approximately 12.5 million barrels of additional above-ground terminalling and storage facilities, the majority of which we expect to place in service during 2007.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2006, PAA/Vulcan owned and operated approximately 25.7 billion cubic feet of underground storage capacity and is constructing an additional 24 billion cubic feet of underground storage capacity, which is expected to be placed in service in stages over the next three years.

Marketing Our marketing segment operations generally consist of the following merchant activities:

- 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 the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions;
- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- arranging for the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

Our marketing activities are designed to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside exposure to opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to reduce the negative impact of market volatility and provide counter-cyclical balance.

Except for pre-defined inventory positions, our policy is generally to purchase only product for which we have a market, to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive, and not to acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on commodity price changes.

In addition to substantial working inventories and working capital associated with its merchant activities, the marketing segment also employs significant volumes of crude oil and LPG as linefill or minimum inventory requirements under service arrangements with transportation carriers and terminalling providers. The marketing segment also employs trucks, trailers, barges, railcars and leased storage.

As of December 31, 2006, the marketing segment owned crude oil and LPG classified as long-term assets and a variety of owned or leased long-term physical assets throughout the United States and Canada, including approximately:

- 7.9 million barrels of crude oil and LPG linefill in pipelines owned by the Partnership;
- 1.5 million barrels of crude oil and LPG linefill in pipelines owned by third parties;
- 500 trucks and 600 trailers; and
- 1,300 railcars.

In connection with its operations, the marketing segment secures transportation and facilities services from the Partnership s other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Inter-segment transportation service rates are based on posted tariffs for pipeline transportation services. Facilities segment services are also obtained at rates consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our marketing segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties.

Counter-Cyclical Balance

Access to storage tankage by our marketing segment provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow associated with this segment. The strategic use of our terminalling and storage assets in conjunction with our marketing operations generally provides us with the flexibility to maintain a base level of margin irrespective of crude oil market conditions and, in certain circumstances, to realize incremental margin during volatile market conditions. See Crude Oil Volatility; Counter-Cyclical Balance; Risk Management.

Business Strategy

Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage and marketing services to our producer, refiner and other customers, and to address the regional supply and demand imbalances for crude oil, refined products and LPG that exist in the United States and Canada by combining the strategic location and distinctive capabilities of our transportation, terminalling and storage assets with our extensive marketing and distribution expertise. We believe successful execution of this strategy will enable us to generate sustainable earnings and cash flow. We intend to grow our business by:

- optimizing our existing assets and realizing cost efficiencies through operational improvements;
- developing and implementing internal growth projects that (i) address evolving crude oil, refined product and LPG needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities;
- utilizing our assets along the Gulf, West and East Coasts along with our Cushing Terminal and leased assets to increase our presence in the waterborne importation of foreign crude oil;
- establishing a presence in the refined product supply and marketing sector;
- selectively pursuing strategic and accretive acquisitions of crude oil, refined product and LPG transportation, terminalling, storage and marketing assets that complement our existing asset base and distribution capabilities; and
- using our terminalling and storage assets in conjunction with our marketing activities to address physical market imbalances, mitigate inherent risks and increase margin.

PAA/Vulcan s natural gas storage assets are also well-positioned to benefit from long-term industry trends and opportunities. Our natural gas storage growth strategies are to develop and implement internal growth projects and to selectively pursue strategic and accretive natural gas storage projects and facilities. We also intend to prudently and economically leverage our asset base, knowledge base and skill sets to participate in other energy-related businesses that have characteristics and opportunities similar to, or that otherwise complement, our existing activities.

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 intend to maintain a 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 50%;
- an average long-term debt-to-EBITDA multiple of approximately 3.5x or less (EBITDA is earnings before interest, taxes, depreciation and amortization); and
- an average EBITDA-to-interest coverage multiple of approximately 3.3x or better.

The first two of these three metrics include long-term debt as a critical measure. In certain market conditions, we also incur short-term debt in connection with marketing activities that involve the simultaneous purchase and forward sale of crude oil. The crude oil purchased in these transactions is hedged, is required to be stored on a month-to-month basis and is sold to high-credit quality counterparties. We do not consider the working capital borrowings associated with this activity to be part of our long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds following delivery of the crude oil. We also anticipate performing similar activities for refined products as we expand our presence in the refined products supply and marketing sector.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund at least 50% of the capital requirements associated with these activities with equity and cash flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile as, in certain cases, these capital expenditures and acquisitions may be financed initially using debt or there may be delays in realizing anticipated synergies from acquisitions or contributions to adjusted EBITDA from capital expansion projects. In this instance, adjusted EBITDA means earnings before interest, tax, depreciation, amortization, Long-Term Incentive Plan charges and gains and losses attributable to Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS 133). At December 31, 2006, we were above our targeted parameter for the long-term debt-to-EBITDA ratio (due primarily to the closing of the Pacific acquisition in November 2006) and within the parameters of the other credit metrics. Based on our December 31, 2006 long-term debt balance and the midpoint of our adjusted EBITDA guidance for 2007 furnished in a Form 8-K dated February 22, 2007, our long-term debt-to-adjusted-EBITDA multiple would be 3.8.

Credit Rating

As of February 2007, our senior unsecured ratings with Standard & Poor s and Moody s Investment Services were BBB- negative outlook and Baa3 stable outlook, respectively, both of which are considered investment grade. We have targeted the attainment of even stronger investment grade ratings of mid to high-BBB and Baa categories for Standard & Poor s and Moody s Investment Services, respectively. We cannot give assurance that our current ratings will remain in effect for any given period of time, that we will be able to attain the higher ratings we have targeted or that one or both of these ratings will not be lowered or withdrawn entirely by the ratings 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 successfully to execute our principal business strategy:

Many of our transportation segment and facilities segment assets are strategically located and operationally flexible and have additional capacity or expansion capability. The majority of our primary transportation segment assets are in crude oil service, are located in well-established oil producing regions and transportation corridors, and are connected, directly or indirectly, with our facilities segment assets located at major trading locations and premium markets that serve as gateways to major North American refinery and distribution markets where we have strong business relationships.

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 the balance of activities provided by our marketing segment provides us with a counter-cyclical balance that generally affords us the flexibility (i) to maintain a base level of margin irrespective of crude oil market conditions and (ii), in certain circumstances, to realize incremental margin during volatile market conditions.

We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities. Over the past nine years, we have completed and integrated approximately 45 acquisitions with an aggregate purchase price of approximately $5.1 billion ($2.6 billion excluding the Pacific acquisition, for which we are still in the process of integrating). We have also implemented internal expansion capital projects totaling over $700 million. In addition, we believe we have significant resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2006, we had approximately $1.3 billion available under our committed credit facilities, subject to continued covenant compliance. We believe we have one of the strongest capital structures relative to other master limited partnerships with capitalizations greater than $1.0 billion. In addition, the investors in our general partner are diverse and financially strong and have demonstrated their support by providing capital to help finance previous acquisitions and expansion activities. We believe they are supportive long-term sponsors of the partnership.

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 more than 15 years with us or our predecessors and affiliates. Certain members of our senior management team own an approximate 5% interest in our general partner and collectively own approximately 850,000 common units, including fully vested options. In addition, through grants of phantom units, the senior management team also owns significant contingent equity incentives that generally vest upon achievement of performance objectives, continued service or both. These interests give management a vested interest in our continued success.

We believe many of these competitive strengths have similar application to our efforts to expand our presence in the refined products, LPG and natural gas storage sectors.

Organizational History

We were formed as a master limited partnership in September 1998 to acquire and operate the midstream crude oil businesses and assets of a predecessor entity. 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 Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder 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. Our general partner, Plains AAP, L.P., is managed by its general partner, Plains All American GP LLC, which has ultimate responsibility for conducting our business and managing our operations. See Item 10. Directors and Executive Officers of our General Partner and Corporate Governance. 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 substantially 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

(1) Based on Form 4 filings for executive officers and directors, 13D filings for Paul G. Allen and Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 26 million limited partner units, representing approximately 23.5% of the limited partner interest.

Acquisitions

The acquisition of assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objective. Such assets and businesses include crude oil related assets, refined products assets and LPG assets, as well as other energy transportation related assets that have characteristics and opportunities similar to 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. Between 1998 and December 31, 2006, we have completed approximately 45 acquisitions for a cumulative purchase price of approximately $5.1 billion.

The following table summarizes acquisitions greater than $50 million that we have completed over the past five years:

Acquisition	Date	Description	Approximate Purchase Price (In millions)	
Pacific Energy Partners LP	November 2006	Merger of Pacific Energy Partners with and into the Partnership	$	2,456
Products Pipeline System	September 2006	Three refined products pipeline systems	$	66
Crude Oil Systems	July 2006	64.35% interest in the Clovelly-to-Meraux Pipeline system; 100% interest in the Bay Marchand-to-Ostrica-to-Alliance system and various interests in the High Island Pipeline System (2)	$	130
Andrews Petroleum and Lone Star Trucking	April 2006	Isomerization, fractionation, marketing and transportation services	$	220
South Louisiana Gathering and Transportation Assets (SemCrude)	April 2006	Crude oil gathering and transportation assets, including inventory, and related contracts in South Louisiana	$	129
Investment in Natural Gas Storage Facilities	September 2005	Joint venture with Vulcan Gas Storage LLC to develop and operate natural gas storage facilities.	$	125(1)
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	$	159
Shell West Texas Assets	August 2002	Basin Pipeline System, Permian Basin Pipeline System and the Rancho Pipeline System	$	324

(1) Represents 50% of the purchase price for the acquisition made by our joint venture. The joint venture completed an acquisition for approximately $250 million during 2005.

(2) Our interest in the High Island Pipeline System was relinquished in November 2006.

Pacific Energy Acquisition

On November 15, 2006 we completed our acquisition of Pacific pursuant to an Agreement and Plan of Merger dated June 11, 2006. The merger-related transactions included: (i) the acquisition from LB Pacific, LP and its affiliates (LB Pacific) of the general partner interest and incentive distribution rights of Pacific as well as approximately 5.2 million Pacific common units and approximately 5.2 million Pacific subordinated units for a total of $700 million and (ii) the acquisition of the balance of Pacific s equity through a unit-for-unit exchange in which each Pacific unitholder (other than LB Pacific) received 0.77 newly issued Partnership common units for each

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Pacific common unit. The total value of the transaction was approximately $2.5 billion, including the assumption of debt and estimated transaction costs. Upon completion of the merger-related transactions, the general partner and limited partner ownership interests in Pacific were extinguished and Pacific was merged with and into the Partnership. The assets acquired in the Pacific acquisition included approximately 4,500 miles of active crude oil pipeline and gathering systems and 550 miles of refined products pipelines, over 13 million barrels of active crude oil and 9 million barrels of refined products storage capacity, a fleet of approximately 75 owned or leased trucks and approximately 1.9 million barrels of crude oil and refined products linefill and working inventory. The Pacific assets complement our existing asset base in California, the Rocky Mountains and Canada, with minimal asset overlap but attractive potential vertical integration opportunities. The results of operations and assets and liabilities from this acquisition (the Pacific acquisition) have been included in our consolidated financial statements since November 15, 2006. The purchase price allocation related to the Pacific acquisition is preliminary and subject to change. See Note 3 to our Consolidated Financial Statements.

Other 2006 Acquisitions

During 2006, we completed six additional acquisitions for aggregate consideration of approximately $565 million. These acquisitions included (i) 100% of the equity interests of Andrews Petroleum and Lone Star Trucking, which provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids (collectively, the Andrews acquisition), (ii) crude oil gathering and transportation assets and related contracts in South Louisiana (SemCrude), (iii) interests in various crude oil pipeline systems in Canada and the U.S. including a 100% interest in the Bay Marchand-to-Ostrica-to-Alliance (BOA) Pipeline, various interests in the High Island Pipeline System (HIPS), and a 64.35% interest in the Clovelly-to-Meraux (CAM) Pipeline system, and (iv) three refined products pipeline systems from Chevron Pipe Line Company.

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, refined products assets, LPG assets and, through our interest in PAA/Vulcan, natural gas storage assets. In addition, we have in the past and intend in the future to evaluate and pursue other energy related assets that have characteristics and opportunities similar to these business lines and enable us to leverage our asset base, knowledge base and skill sets. Such acquisition efforts may involve participation by us in processes that have been made public and involve a number of potential buyers, commonly referred to as auction processes, as well as situations in which we believe we are the only party or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations.

Crude Oil Market Overview

Our assets and our business strategy are designed to service our producer and refiner customers by addressing regional crude oil supply and demand imbalances that exist in the United States and Canada. According to the Energy Information Administration (EIA), during the twelve months ended October 2006, the United States consumed approximately 15.2 million barrels of crude oil per day, while only producing 5.1 million barrels per day. Accordingly, the United States relies on foreign imports for nearly 66% of the crude oil used by U.S. domestic refineries. This imbalance represents a continuing trend. Foreign imports of crude oil into the U.S. have tripled over the last 21 years, increasing from 3.2 million barrels per day in 1985 to 10.2 million barrels per day for the 12 months ended October 2006, as U.S. refinery demand has increased and domestic crude oil production has declined due to natural depletion.

The Department of Energy segregates the United States into five Petroleum Administration Defense Districts (PADDs) which are used by the energy industry for reporting statistics regarding crude oil supply and demand. The table below sets forth supply, demand and shortfall information for each PADD for the twelve months ended October 2006 and is derived from information published by the EIA (see EIA website at www.eia.doe.gov).

Petroleum Administration Defense District	Regional Supply	Refinery Demand	Supply Shortfall
	(Millions of barrels per day)		
PADD I (East Coast)	0.0	1.5	(1.5)
PADD II (Midwest)	0.5	3.3	(2.8)
PADD III (South)	2.8	7.2	(4.4)
PADD IV (Rockies)	0.3	0.5	(0.2)
PADD V (West Coast)	1.5	2.7	(1.2)
Total U.S.	5.1	15.2	(10.1)

Although PADD III has the largest supply shortfall, PADD II is believed to be the most critical region with respect to supply and transportation logistics because it is the largest, most highly populated area of the U.S. that does not have direct access to oceanborne cargoes.

Over the last 21 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 450,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1985 to 3.3 million barrels per day for the twelve months ended October 2006. As a result, the volume of crude oil transported into PADD II has increased 71%, from 1.7 million barrels per day to 2.9 million barrels per day. This aggregate shortfall is principally supplied by direct imports from Canada to the north and from the Gulf Coast area and the Cushing Interchange to the south.

The logistical transportation, terminalling and storage challenges associated with regional volumetric supply and demand imbalances are further complicated by the fact that crude oil from different sources is not fungible. The crude slate available to U.S. refineries consists of a substantial number of different grades and varieties of crude oil. Each crude grade has distinguishing physical properties, such as specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content as well as varying economic attributes. In many cases, these factors result in the need for such grades to be batched or segregated in the transportation and storage processes, blended to precise specifications or adjusted in value. In addition, from time to time, natural disasters and geopolitical factors, such as hurricanes, earthquakes, tsunamis, inclement weather, labor strikes, refinery disruptions, embargoes and armed conflicts, may impact supply, demand and transportation and storage logistics.

Refined Products Market Overview

Once crude oil is transported to a refinery, it is broken down into different petroleum products. These refined products fall into three major categories: fuels such as motor gasoline and distillate fuel oil (diesel fuel); finished non-fuel products such as solvents and lubricating oils; and feedstocks for the petrochemical industry such as naphtha and various refinery gases. Demand is greatest for products in the fuels category, particularly motor gasoline.

The characteristics of the gasoline produced depend upon the setup of the refinery at which it is produced and the type of crude oil that is used. Gasoline characteristics are also impacted by other ingredients that may be blended into it, such as ethanol. The performance of the gasoline must meet industry standards and environmental regulations that vary based on location.

After crude oil is refined into gasoline and other petroleum products, the products must be distributed to consumers. The majority of products are shipped by pipeline to storage terminals near consuming areas, and then loaded into trucks for delivery to gasoline stations or other end users. Some of the products which are used as feedstocks are typically transported by pipeline to chemical plants.

Demand for refined products is increasing and is affected by price levels, economic growth trends and, to a lesser extent, weather conditions. According to the EIA, consumption of refined products in the United States has risen steadily from approximately 15.7 million barrels per day in 1985 to approximately 20.7 million barrels per day for the twelve months ended October 2006, an increase of 31%. By 2030, the EIA estimates that the U.S. will consume approximately 27.6 million barrels per day of refined products, an increase of 33% over the last twelve months levels. We believe that the additional demand will be met by growth in the capacity of existing refineries through large expansion projects and capacity creep as well as increased imports of refined products, both of which we believe will generate incremental demand for midstream infrastructure, such as pipelines and terminals.

We believe that demand for refined products pipeline and terminalling infrastructure will also increase as a result of:

- multiple specifications of existing products (also referred to as boutique gasoline blends);
- specification changes to existing products, such as ultra low sulfur diesel;
- new products, such as bio-fuels;
- the aging of existing infrastructure; and
- the potential reduction in storage capacity due to regulations governing the inspection, repair, alteration and construction of storage tanks.

We intend to grow our asset base in the refined products business through expansion projects and future acquisitions. Consistent with our plan to apply our proven business model to these assets, we also intend to optimize the value of our refined products assets and better serve the needs of our customers by building a complementary refined products supply and marketing business.

LPG Products Market Overview

LPGs are a group of hydrogen-based gases that are derived from crude oil refining and natural gas processing. They include ethane, propane, normal butane, isobutane and other related products. For transportation purposes, these gases are liquefied through pressurization. LPG is also imported into the U.S. from Canada and other parts of the world.

LPGs are principally used as feedstock for petrochemical production processes. Individual LPG products have specific uses. For example, propane is used for home heating, water heating, cooking, crop drying and tobacco curing. As a motor fuel, propane is burned in internal combustion engines that power over-the-road vehicles, forklifts and stationary engines. Ethane is used primarily as a petrochemical feedstock. Normal butane is used as a petrochemical feedstock, as a blend stock for motor gasoline, and to derive isobutane through isomerization. Isobutane is principally used in refinery alkylation to enhance the octane content of motor gasoline or in the production of isooctane or other octane additives. Certain LPGs are also used as diluent in the transportation of heavy oil, particularly in Canada.

According to the EIA, consumption of LPGs in the United States has risen steadily from approximately 1.6 million barrels per day in 1985 to approximately 2.1 million barrels per day for the twelve months ended October 2006, an increase of 33%. By 2030, the EIA estimates that the U.S. will consume approximately 2.4 million barrels per day of LPGs, an increase of 13% over the last twelve months levels. We believe that the additional demand will result in an increased demand for LPG infrastructure, including pipelines, storage facilities, processing facilities and import terminals.

We intend to grow our asset base in the LPG business through expansion projects and future acquisitions. We believe that our asset base, which is principally located in the upper tier of the U.S., Oklahoma and California, provides flexibility in meeting the needs of our customers and opportunities to capitalize on regional supply/demand imbalances in LPG markets.

Natural Gas Storage Market Overview

After treatment for impurities such as carbon dioxide and hydrogen sulfide and processing to separate heavier hydrocarbons from the gas stream, natural gas from one source generally is fungible with natural gas from any other source. Because of its fungibility and physical volatility and the fact that it is transported in a gaseous state, natural gas presents different logistical transportation challenges than crude oil and refined products; however, we believe the U.S. natural gas supply and demand situation will ultimately face storage challenges very similar to those that exist in the North American crude oil sector. We believe these factors will result in an increased need and an attractive valuation for natural gas storage facilities in order to balance market demands. From 1990 to 2005, domestic natural gas production grew approximately 2% while domestic natural gas consumption rose approximately 15%, resulting in an approximate 175% increase in the domestic supply shortfall over that time period. In addition, significant excess domestic production capacity contractually withheld from the market by take-or-pay contracts between natural gas producers and purchasers in the late 1980s and early 1990s has since been eliminated. This trend of an increasing domestic supply shortfall is expected to continue. By 2030, the EIA estimates that the U.S. will require approximately 5.5 trillion cubic feet of annual net natural gas imports (or approximately 15 billion cubic feet per day) to meet its demand, nearly 1.4 times the 2005 annual shortfall.

The vast majority of the projected supply shortfall is expected to be met with imports of liquefied natural gas (LNG). According to the Federal Energy Regulatory Commission (FERC) as of January 2007, plans for 34 new LNG terminals in the United States and Bahamas have been proposed, 17 of which are to be situated along the Gulf Coast. Of the 17 proposed Gulf Coast facilities, three are under construction, nine have been approved by the appropriate regulatory agencies, and five have been proposed to the appropriate regulatory agencies. These facilities will be used to re-gasify the LNG prior to shipment in pipelines to natural gas markets.

Normal depletion of regional natural gas supplies will require additional storage capacity to pre-position natural gas supplies for seasonal usage. In addition, we believe that the growth of LNG as a supply source will also increase the demand for natural gas storage as a result of inconsistent surges and shortfalls in supply based on LNG tanker deliveries, similar in many respects to the issues associated with waterborne crude oil imports. LNG shipments are exposed to a number of risks related to natural disasters and geopolitical factors, including hurricanes, earthquakes, tsunamis, inclement weather, labor strikes and facility disruptions, which can impact supply, demand and transportation and storage logistics. These factors are in addition to the already dramatic impact of seasonality and regional weather issues on natural gas markets.

Description of Segments and Associated Assets

Our business activities are conducted through three segments Transportation, Facilities and Marketing. We have an extensive network of transportation, terminalling and storage facilities at major market hubs and in key oil producing basins and crude oil, refined product and LPG transportation corridors in the United States and Canada.

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

Transportation

Our transportation segment operations generally consist of fee-based activities associated with transporting volumes of crude oil and refined products on pipelines and gathering systems.

As of December 31, 2006, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 20,000 miles of active pipelines and gathering systems;
- 30 million barrels of tank capacity used primarily to facilitate pipeline movements; and
- 57 transport and storage barges and 30 transport tugs through our 50% interest in Settoon Towing.

We generate revenue through a combination of tariffs, third party leases of pipeline capacity, transportation fees, barrel exchanges and buy/sell arrangements. We also include in this segment our equity earnings from our investments in the Butte and Frontier pipeline systems, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

Substantially all of our pipeline systems are controlled or monitored from one of four central control rooms with computer systems designed to continuously monitor real-time operational data, such as 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 the majority of our pump stations on the pipeline systems. Pump stations, storage facilities and meter measurement

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points along the pipeline systems are linked by satellite, radio, fiber optic cable, telephone, or a combination thereof to provide communications for remote monitoring and in some instances operational control, which reduces our requirement for full-time site personnel at most of these locations.

We make repairs on and replacements of our mainline pipeline systems 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 and refined product streams and other protection systems typically used in the industry. Maintenance facilities containing spare parts and equipment for pipe repairs, as well as 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 (API), the Canadian Standards Association and accepted industry practice as required or considered appropriate under the circumstances. See Regulation Pipeline and Storage Regulation.

Following is a tabular presentation of all of our active pipeline assets in the United States and Canada, grouped by geographic location:

Region	**Pipeline/Gathering Systems**	**% Ownership**	**System Miles**	**2006 Average Net Barrels per Day(1)**
Southwest US	Basin	87%	519	332,000
	Dollarhide	100%	24	5,000
	El Paso Albuquerque (refined products)	100%	257	28,000
	Garden City	100%	63	10,000
	Hardeman	100%	107	4,000
	Iatan	100%	360	21,000
	Iraan	100%	98	31,000
	Merkel	100%	128	4,000
	Mesa	63%	80	31,000
	New Mexico	100%	1,163	81,000
	Permian Basin Gathering	100%	780	59,000
	Spraberry Gathering	100%	727	42,000
	Texas	100%	1,498	75,000
	West Texas Gathering	100%	738	85,000
Western US	All American	100%	136	49,000
	Line 63	100%	323	86,000
	Line 2000	100%	151	73,000
	San Joaquin Valley	100%	77	88,000
US Rocky Mountain	AREPI	100%	42	46,000
	Beartooth	50%	76	15,000
	Bighorn	58%	336	15,000
	Butte(3)	22%	370	18,000
	Frontier	22%	290	46,000
	Glacier(3)	21%	614	20,000
	North Dakota/Trenton	100%	731	89,000
	Rocky Mountain Gathering	100%	400	27,000

	Rocky Mountain Products (refined products)	100%	554	61,000
	Salt Lake City Core	100%	960	45,000
US Gulf Coast	ArkLaTex	100%	87	21,000
	Atchafalaya	100%	35	20,000

Region	Pipeline/Gathering Systems	% Ownership	System Miles	2006 Average Net Barrels per Day(1)
	BOA	100%	107	82,000
	Bridger Lakes	100%	19	1,000
	CAM (Segment I/Segment II)	60%/0%	47	131,000
	Capline(3)	22%	633	160,000
	Capwood/Patoka	76%	58	99,000
	Cocodrie	100%	66	6,000
	East Texas	100%	9	8,000
	Eugene Island	100%	66	11,000
	Golden Meadow	100%	37	3,000
	Deleck	100%	119	29,000
	Mississippi/Alabama	100%	837	87,000
	Pearsall	100%	62	2,000
	Red River	100%	359	13,000
	Red Rock	100%	54	3,000
	Sabine Pass	100%	33	12,000
	Southwest Louisiana	100%	205	4,000
	Turtle Bayou	100%	14	3,000
Central US	Cushing to Broome	100%	103	73,000
	Midcontinent	100%	1,197	35,000
	Oklahoma	100%	1,629	59,000
	Domestic Total		17,378	2,348,000
Canada	Cactus Lake(2)	100%	115	16,000
	Cal Ven	100%	148	16,000
	Joarcam	100%	31	4,000
	Manito	100%	381	61,000
	Milk River	100%	33	96,000
	Rangeland	100%	938	66,000
	South Saskatchewan	100%	344	47,000
	Wapella	100%	73	11,000
	Wascana	100%	107	3,000
	Canada Total		2,170	320,000
	Total		19,548	2,668,000

(1) Represents average volumes for the entire year of 2006.

(2) For January through March 2006, our interest was 15%; we acquired the remaining interest in March 2006.

(3) Non-operated pipeline.

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Below is a detailed description of our more significant transportation segment assets.

Major Transportation 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, Line 2000 and Line 63, as well as other 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 and other producers that together own approximately 70% 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 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 existing means of transporting their production and, therefore, ship their volumes on the All American Pipeline at the filed tariffs. For 2006 and 2005, tariffs on the All American Pipeline averaged $2.07 per barrel and $1.87 per barrel, respectively. The agreements do not require these owners to transport a minimum volume. These agreements, which had an initial term expiring in August 2007, include an annual one year evergreen provision that requires one year s advance notice to cancel.

With the acquisition of Line 2000 and Line 63, a significant portion of our transportation segment profit is derived from the pipeline transportation business associated with the Santa Ynez and Point Arguello fields and fields located in the San Joaquin Valley. We estimate that a 5,000 barrel per day decline in volumes shipped from the outer continental shelf fields would result in a decrease in annual transportation segment profit of approximately $6.1 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated $3.2 million decrease in annual transportation segment profit.

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

	Year Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
	(Barrels in thousands)				
Average daily volumes received from:					
Point Arguello (at Gaviota)	9	10	10	13	16
Santa Ynez (at Las Flores)	40	41	44	46	50
Total	49	51	54	59	66

Basin Pipeline System

We own an approximate 87% undivided joint interest in and act as operator of the Basin Pipeline System. The Basin system is a primary route for transporting Permian Basin crude oil to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. The Basin system is a 519-mile mainline, telescoping crude oil system with a capacity ranging from approximately 144,000 barrels per day to 400,000 barrels per day depending on the segment. System throughput (as measured by system deliveries) was approximately 332,000 barrels per day (net to our interest) during 2006. 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 transportation segment profit of approximately $1.8 million.

The Basin system consists of four primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland; (ii) barrels that are shipped from Midland to connecting carriers at Colorado City; (iii) barrels that are shipped from Midland and Colorado City to connecting carriers at either Wichita Falls or Cushing; and (iv) foreign and Gulf of Mexico barrels that are delivered into Basin at Wichita Falls and delivered to connecting carriers at Cushing. The system also includes approximately 5.5 million barrels (4.8 million barrels, net to our interest) of crude oil storage capacity located along the system. In 2004, we expanded an approximate 425-mile section of the system from Midland to Cushing. 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 FERC.

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. Shell is the operator of this system. 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 the Louisiana Offshore Oil Port, 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. During 2006, throughput on our interest averaged approximately 160,000 barrels per day. A 10,000 barrel per day decline in volumes shipped on the Capline system would result in a decrease in our annual transportation segment profit of approximately $1.3 million.

The Capwood Pipeline System, in which we own a 76% undivided joint interest, is a 58-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 by volumes of Canadian crude that can be delivered to Patoka via the Mustang Pipeline. PAA assumed the operatorship of the Capwood system from Shell Pipeline Company LP at the time of purchase. During 2006 throughput net to our interest averaged approximately 99,000 barrels per day.

Line 2000

We own and operate Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station and transports crude oil produced in the San Joaquin Valley and California outer continental shelf to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 151-mile trunk pipeline with a throughput capacity of 130,000 barrels per day. For the full year of 2006, throughput on Line 2000 averaged approximately 73,000 barrels per day.

Line 63

The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California outer continental shelf to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 107-mile trunk pipeline, originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The Line 63 system includes 60 miles of distribution pipelines in the Los Angeles Basin and in the Bakersfield area, 156 miles of gathering pipelines in the San Joaquin Valley, and 22 storage tanks with approximately 1.2 million barrels of storage capacity. These storage assets, the majority of which are located in the San Joaquin Valley, are used primarily to facilitate the transportation of crude oil on the Line 63 system. Line 63 has a throughput capacity of approximately 105,000 barrels per day. For the full year of 2006, throughput on Line 63 averaged approximately 86,000 barrels per day.

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Rangeland System

The Rangeland system includes the Mid Alberta Pipeline and the Rangeland Pipeline. The Mid Alberta Pipeline is a 138-mile proprietary pipeline with a throughput capacity of approximately 50,000 barrels per day if transporting light crude oil. The Mid Alberta Pipeline originates in Edmonton, Alberta and terminates in Sundre, Alberta where it connects to the Rangeland Pipeline. The Rangeland Pipeline is a proprietary pipeline system that consists of approximately 800 miles of gathering and trunk pipelines and is capable of transporting crude oil, condensate and butane either north to Edmonton, Alberta via third-party pipeline connections or south to the U.S./Canadian border near Cutbank, Montana where it connects to our Western Corridor system. The trunk pipeline from Sundre, Alberta to the U.S./Canadian border consists of approximately 250 miles of trunk pipelines and has a current throughput capacity of approximately 85,000 barrels per day if transporting light crude oil. The trunk system from Sundre, Alberta north to Rimbey, Alberta is a bi-directional system that consists of three parallel trunk pipelines: a 56-mile pipeline for low sulfur crude oil, a 63-mile pipeline for high sulfur crude oil, and a 56-mile pipeline for condensate and butane. From Rimbey, third-party pipelines move product north to Edmonton. For the full year of 2006, 22,500 barrels per day of crude oil was transported on the segment of the pipeline from Sundre north to Edmonton and 43,500 barrels per day was transported on the pipeline from Sundre south to the United States.

Western Corridor System

The Western Corridor system is an interstate and intrastate common carrier crude oil pipeline system that consists of 1,012 miles of pipelines extending from the U.S./Canadian border near Cutbank, Montana, where it receives deliveries from our Rangeland Pipeline and the Cenex Pipeline, and terminates at Guernsey, Wyoming with connections to our Salt Lake City Core system, the Frontier Pipeline and various third-party pipelines. The Western Corridor system consists of three contiguous trunk pipelines: Glacier Pipeline, Beartooth Pipeline and Big Horn Pipeline.

Glacier Pipeline. We own a 20.8% undivided interest in Glacier Pipeline, which provides us with approximately 25,000 barrels per day of throughput capacity. Glacier Pipeline consists of 614 miles of two parallel crude oil pipelines, a 277-mile, 12-inch trunk pipeline, a 288-mile, 8-inch and 10-inch trunk pipeline, and a 49-mile 12-inch loop line, all extending from the Canadian border and Cutbank, Montana to Billings, Montana. Shipments on Glacier Pipeline can be delivered either to refineries in Billings and Laurel, Montana or into our Beartooth pipeline. For the full year of 2006, our throughput on Glacier Pipeline was approximately 20,000 barrels per day. ConocoPhillips Pipe Line Company is the operator of the Glacier Pipeline.

Beartooth Pipeline. We own a 50% undivided interest in Beartooth Pipeline, which provides us with approximately 25,000 barrels per day of throughput capacity. Beartooth Pipeline is a 76-mile, 12-inch trunk pipeline from Billings, Montana to Elk Basin, Wyoming. Beartooth Pipeline was constructed to connect our Glacier Pipeline with our Big Horn Pipeline where all shipments are delivered. For the full year of 2006, our throughput on Beartooth Pipeline was approximately 15,000 barrels per day. We operate the Beartooth Pipeline.

Big Horn Pipeline. We own a 57.6% undivided interest in Big Horn Pipeline, which provides us with approximately 33,900 barrels per day of throughput capacity. Big Horn Pipeline consists of a 231-mile, 12-inch trunk pipeline from Elk Basin, Wyoming to Casper, Wyoming and a 105-mile, 12-inch trunk pipeline from Casper, Wyoming to Guernsey, Wyoming. Shipments on our Big Horn Pipeline can be delivered either to Wyoming refineries directly, into Frontier Pipeline at Casper, Wyoming or into the Salt Lake City Core system, the Suncor Pipeline, or Platte Pipeline at Guernsey, Wyoming. For the full year of 2006, our interest in throughput on Big Horn Pipeline was approximately 15,000 barrels per day. We operate the Big Horn Pipeline.

We also own various undivided interests in 22 storage tanks along the Western Corridor System that provide us with a total of approximately 1.3 million barrels of storage capacity.

Salt Lake City Core System

We own and operate the Salt Lake City Core system, an interstate and intrastate common carrier crude oil pipeline system that transports crude oil produced in Canada and the U.S. Rocky Mountain region primarily to refiners in Salt Lake City. The Salt Lake City Core system consists of 960 miles of trunk pipelines with a combined throughput capacity of approximately 114,000 barrels per day to Salt Lake City, 209 miles of gathering pipelines, and 32 storage tanks with a total of approximately 1.4 million barrels of storage capacity. This system originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming and can deliver to Salt Lake City, Utah and Rangely, Colorado. For the full year of 2006, approximately 45,000 barrels per day were delivered to Salt Lake City directly through our pipelines and of this amount approximately 11,600 barrels per day were delivered indirectly through connections to a Chevron pipeline. We are constructing a 95-mile expansion of this system to Salt Lake City, which is scheduled to be completed in early 2008. When completed, the pipeline will have an estimated capacity of 120,000 barrels per day. The cost of this project is supported by 10-year transportation contracts that have been executed with four Salt Lake City refiners. Also, in February 2007, we signed a letter of intent to sell a 25% interest in this line to Holly Energy Partners, L.P. As part of this agreement, Holly Refining and Marketing will enter into a 10-year transportation agreement on terms consistent with the four previously committed refiners. Plains portion of the total project cost is estimated to be $75 million, of which approximately $55 million is scheduled to be spent in 2007.

Cheyenne Pipeline

Pursuant to a transportation agreement, we are constructing a 16-inch crude oil pipeline, approximately 93 miles in length, from Fort Laramie to Cheyenne, Wyoming, in exchange for a ten-year firm commitment to ship 35,000 barrels per day on the new pipeline and lease approximately 300,000 barrels of storage capacity at Fort Laramie. The project also includes 10 miles of a 24-inch pipeline from Guernsey to Fort Laramie. The total project cost is estimated to be $59 million of which $34 million is the estimated remaining project cost to be incurred in 2007. The project is expected to be completed by the end of the second quarter of 2007. Initial capacity will be 55,000 barrels per day.

Rocky Mountain Products Pipeline System

The Rocky Mountain Products Pipeline System consists of a 554-mile refined products pipeline extending from Casper, Wyoming east to Rapid City, South Dakota and south to Colorado Springs, Colorado. The Rocky Mountain Products Pipeline originates near Casper, Wyoming, where it serves as a connecting point with Sinclair s Little America Refinery and the ConocoPhillips Seminole Pipeline, which transports product from Billings, Montana area refineries. The system continues to Douglas, Wyoming where it branches off to serve our Rapid City, South Dakota terminal approximately 190 miles away. This segment also receives product from Wyoming Refining Company via a third-party pipeline at a connection located near the border of Wyoming and South Dakota. From Douglas, Wyoming, the Rocky Mountain Products Pipeline continues south to our terminals at Cheyenne, Wyoming, where it receives refined products from a refinery via a third-party pipeline, and continues on to Denver, Colorado and Colorado Springs, Colorado. Our Denver terminal also receives refined products from Sinclair Pipeline. The various segments of the Rocky Mountain Products Pipeline have a combined throughput capacity of 85,000 barrels per day. For the full year of 2006, our throughput on the Rocky Mountain Products Pipeline System was approximately 61,000 barrels per day (average for the entire year). The Rocky Mountain Products Pipeline System includes products terminals at Rapid City, South Dakota, Cheyenne, Wyoming and Denver and Colorado Springs, Colorado with a combined storage capacity of 1.7 million barrels.

El Paso to Albuquerque System

The El Paso to Albuquerque refined products pipeline system is one of three refined products pipeline systems located in Texas and New Mexico. The El Paso to Albuquerque Products Pipeline system is a 257-mile system originating in El Paso, Texas, and terminating in Albuquerque, New Mexico, with approximately 28,200 barrels per day of throughput capacity. The El Paso to Albuquerque system receives various types of refined product at its origination station from Western Refining and Navajo Refining, and delivers product to third party terminals in Belen and Albuquerque, New Mexico. For the full year of 2006, our throughput on the El Paso to Albuquerque system was approximately 28,000 barrels per day.

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Facilities

Our facilities segment generally consists of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services.

As of December 31, 2006, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 30 million barrels of active, above-ground terminalling and storage facilities;
- approximately 1.3 million barrels of active, underground terminalling and storage facilities; and
- two fractionation plants and one isomerization unit with aggregate processing capacity of 26,400 barrels per day.

At year-end 2006, the Partnership was in the process of constructing approximately 12.5 million barrels of additional above-ground terminalling and storage facilities, which we expect to place in service during 2007 and 2008.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2006, PAA/Vulcan owned and operated approximately 25.7 billion cubic feet of underground storage capacity and was constructing an additional 24 billion cubic feet of underground storage capacity which is expected to be placed in service in stages over the next three years.

We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Revenues generated in this segment include (i) storage fees that are generated when we lease tank capacity and (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil from one connecting pipeline and redeliver crude oil to another connecting carrier.

Following is a tabular presentation of our active facilities segment assets and those under construction in the United States and Canada, grouped by product type:

Facility	Facility Description	Capacity
Crude oil and refined products		
Cushing	Crude oil terminalling and storage facility at the Cushing Interchange	7.4 million barrels
Eastern	Refined products terminals in Philadelphia, Pennsylvania and Paulsboro, New Jersey	3.1 million barrels
Kerrobert	Crude oil terminalling and storage facility located near Kerrobert, Saskatchewan	1.7 million barrels
LA Basin	Crude oil and refined products storage and pipeline distribution system in Los Angeles Basin	9.0 million barrels
Martinez and Richmond	Crude oil and refined products storage terminals in the San Francisco area	4.5 million barrels
Mobile and Ten Mile		3.3 million barrels

	Crude oil marine and storage terminals in Mobile, Alabama	
St. James	Crude oil terminal in Louisiana (Phase I)	1.2 million barrels
LPG		
Alto	Butane and propane salt cavern storage terminal in Michigan	1.3 million barrels
Arlington and Washougal	Transloading LPG terminals in Washington	< 0.1 million barrels
Claremont	Transloading LPG terminal in New Hampshire	< 0.1 million barrels
Cordova	Transloading LPG terminal in Illinois	< 0.1 million barrels
Fort Madison	Propane pipeline terminal in Iowa	< 0.1 million barrels
High Prairie	Fractionation facility in Alberta, producing butane, propane and stabilized condensate	< 0.1 million barrels
Kincheloe	Transloading LPG terminal in Michigan	< 0.1 million barrels
Schaefferstown	Refrigerated storage terminal in Pennsylvania	0.5 million barrels

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Facility	Facility Description	Capacity
Shafter	Isomerization facility in California, producing isobutane, propane and stabilized condensate	0.2 million barrels
Tulsa	Propane pipeline terminal in Oklahoma	< 0.1 million barrels
Natural Gas		
Bluewater/Kimball	Natural gas storage facility in Michigan	25.7 Bcf (1)
Under Construction		
Martinez	Expansion to crude oil and refined products terminal in California	0.9 million barrels
Mobile and Ten Mile	Expansion to crude oil terminal in Alabama	0.6 million barrels
Patoka	Crude oil storage and terminal facility in Patoka, Illinois	2.6 million barrels
Pier 400	Deepwater petroleum import terminal in the Port of Los Angeles	Under Development
Pine Prairie	Natural gas storage facility in Louisiana	24 Bcf (1)
Cushing	Expansion to crude oil terminalling and storage facility at the Cushing Interchange	3.4 million barrels
St. James	Expansion to crude oil terminal in Louisiana (Phase I and II)	5.0 million barrels

(1) Our interest in these facilities is 50% of the capacity stated above

Below is a detailed description of our more significant facilities segment assets.

Major Facilities Assets

Cushing Terminal

Our Cushing Terminal is located at the Cushing Interchange, 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 facility was designed to handle multiple grades of crude oil while minimizing the interface and enable deliveries to connecting carriers at their maximum rate. The facility also incorporates numerous environmental and operations safeguards that distinguish it from all other facilities at the Cushing Interchange.

Since 1999, we have completed five separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 7.4 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks and twenty 270,000-barrel tanks, all of which are used to store and terminal crude oil. Our tankage ranges in age from one year to approximately 13 years with an average age of six years. In contrast, we estimate that the average age of the remaining tanks in Cushing owned by third parties is in excess of 40 years.

In September 2006, we announced our Phase VI expansion of our Cushing Terminal facility. Under the Phase VI expansion, we will construct approximately 3.4 million barrels of additional tankage. The Phase VI project will expand the total capacity of the facility to 10.8 million barrels and, including manifold modifications, is expected to cost approximately $48 million of which $27 million is the estimated remaining project cost to be incurred in 2007. We estimate that the new tankage will become operational during the fourth quarter of 2007. The expansion is supported by multi-year lease agreements.

Eastern Terminals

We own three refined product terminals in the Philadelphia, Pennsylvania area: a 0.9 million barrel terminal in North Philadelphia, a 0.6 million barrel terminal in South Philadelphia and a 1.6 million barrel terminal in Paulsboro, New Jersey. Our Philadelphia area terminals have 40 storage tanks with combined storage capacity of 3.1 million barrels. The terminals have 20 truck loading lanes, two barge docks and a ship dock. The Philadelphia area terminals provide services and products to all of the refiners in the Philadelphia harbor. The North Philadelphia and Paulsboro terminals have dock facilities that can load approximately 10,000 to 12,000 barrels per hour of refined products and black oils. The Philadelphia area terminals also receive products from connecting pipelines and offer truck loading services, barge cleaning and tug fuel services.

At our Philadelphia area terminals, we have completed an ethanol expansion project which enabled us to increase our ethanol handling and blending capabilities as well as increase our marine receipt capabilities. We plan to expand our Paulsboro facility by approximately 1.0 million barrels consisting of eight tanks ranging from 50,000 barrels to 150,000 barrels. This expansion is in the permitting stage and is scheduled to be completed in 2008 at an estimated cost of $31 million, of which approximately $20 million is scheduled to be spent in 2007.

Kerrobert

We own a crude oil and condensate storage and terminalling facility located near Kerrobert, Saskatchewan with a storage capacity of approximately 1.7 million barrels. The facility is connected to our Manito and Cactus Lake pipeline systems. In 2006, we increased the storage capacity at our Kerrobert facility by 900,000 barrels of tankage, bringing the total storage capacity to 1.7 million barrels. The cost of the expansion is estimated to be approximately $47 million, of which approximately $14 million is the estimated remaining project cost to be incurred in 2007.

Los Angeles Area Storage and Distribution System

We own four crude oil and refined product storage facilities in the Los Angeles area with a total of 9.0 million barrels of storage capacity and a distribution pipeline system of approximately 70 miles of pipeline in the Los Angeles Basin. The storage facility includes 34 storage tanks. Approximately 7.0 million barrels of the storage capacity are in active commercial service, 0.5 million barrels are used primarily for throughput to other storage tanks and do not generate revenue independently, approximately 1.2 million barrels are idle but could be reconditioned and brought into service and approximately 0.3 million barrels are in displacement oil service. We refurbished and placed in service 0.3 million barrels of black oil storage capacity in the third quarter of 2006 and expect to complete refurbishing an additional 0.3 million barrels of black oil storage in the first quarter of 2007. We are also making infrastructure changes to increase pumping capacity and improve operating efficiencies, which we expect to complete in 2007. We use the Los Angeles area storage and distribution system to service the storage and distribution needs of the refining, pipeline and marine terminal industries in the Los Angeles Basin. In addition, the Los Angeles area system has 17 storage tanks with a total of approximately 0.4 million barrels of storage capacity that are out of service. We are in the process of completing refurbishments and infrastructure changes at this facility. The Los Angeles area system s pipeline distribution assets connect its storage assets with major refineries, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin. The system is capable of loading and off-loading marine shipments at a rate of 25,000 barrels per hour and transporting the product directly to or from certain refineries, other pipelines or its storage facilities. In addition, we can deliver crude oil and feedstocks from our storage facilities to the refineries served by this system at rates of up to 6,000 barrels per hour.

Martinez and Richmond Terminals

We own two terminals in the San Francisco, California area: a 3.9 million barrel terminal at Martinez (which provides refined product and crude oil service) and a 0.6 million barrel terminal at Richmond (which provides refined product service). Our San Francisco area terminals currently have 49 storage tanks with 4.5 million barrels of combined storage capacity that are connected to area refineries through a network of owned and third-party pipelines that carry crude oil and refined products to and from area refineries. The terminals have dock facilities that can load between approximately 4,000 and 10,000 barrels per hour of refined products. There is also a rail spur at the Richmond terminal that is able to receive products by train.

We recently added 450,000 barrels of storage capacity at the Martinez terminal and we are constructing an additional 850,000 barrels of storage capacity for completion in 2007 at a remaining estimated project cost of approximately $27 million.

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Mobile and Ten Mile Terminal

We have a marine terminal in Mobile, Alabama (the Mobile Terminal) that consists of eighteen tanks ranging in size from 10,000 barrels to 225,000 barrels, with current useable capacity of 1.5 million barrels. Approximately 1.8 million barrels of additional storage capacity is available at our nearby Ten Mile Facility through a 36 pipeline connecting the two facilities. In 2006, we started construction of a 600,000 barrel tank at the Ten Mile Facility. The cost for this tank is expected to be approximately $6.4 million of which $5.8 million is the estimated remaining project cost to be incurred in 2007. The new tank is expected to be in service in the second quarter of 2007.

The Mobile Terminal is equipped with a ship/tanker dock, barge dock, truck-unloading facilities and various third party connections for crude oil movements to area refiners. Additionally, the Mobile Terminal serves as a source for imports of foreign crude oil to PADD II refiners through our Mississippi/Alabama pipeline system, which connects to the Capline System at our station in Liberty, Mississippi.

St. James Terminal

In 2005, we began construction of a 3.5 million barrel crude oil terminal at the St. James crude oil interchange in Louisiana, which is one of the three most liquid crude oil interchanges in the United States. In the first phase of construction, we plan to build seven tanks ranging from 210,000 barrels to 670,000 barrels with an aggregate shell capacity of approximately 3.5 million barrels. At December 31, 2006, 1.2 million barrels of capacity were in service. The remaining capacity of Phase I is expected to be operational during the first quarter of 2007. The estimated total cost of Phase I is estimated to be approximately $105 million, of which $17.3 million is the estimated remaining project cost to be incurred in 2007. The facility will also include a manifold and header system that will allow for receipts and deliveries with connecting pipelines at their maximum operating capacity.

Under the Phase II project, we will construct approximately 2.7 million barrels of additional tankage at the facility. The Phase II project will expand the total capacity of the facility to 6.2 million barrels and is expected to cost approximately $64 million of which $43 million is the estimated project cost to be incurred in 2007. We estimate that the Phase II tankage will become operational during the first quarter of 2008.

Shafter

Our Shafter facility (acquired through the Andrews acquisition) provides isomerization and fractionation services to producers and customers of natural gas liquids (NGLs) throughout the Western United States. The primary assets consist of 200,000 barrels of NGL storage, a processing facility with butane isomerization capacity of 14,000 barrels per day and NGL fractionation capacity of 9,600 barrels per day, and office facilities in California.

Patoka Terminal

In December 2006, we announced that we will build a 2.6 million barrel crude oil storage and terminal facility at the Patoka interchange in Patoka, Illinois. We anticipate that the new facility will become operational during the second half of 2008 for a total cost of approximately $77 million, including land costs. We expect to incur approximately half of the cost in 2007 and the remainder in 2008. Patoka is a growing regional hub with access to domestic and foreign crude oil volumes moving north on the Capline system as well as Canadian barrels moving south. This project will have the ability to be expanded should market conditions warrant.

Pier 400

We are in the process of developing a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles to handle marine receipts of crude oil and refinery feedstocks. As currently envisioned, the project would include a deep water berth, high capacity transfer infrastructure and storage tanks, with a pipeline distribution system that will connect to various customers.

We have entered into agreements with ConocoPhillips and two subsidiaries of Valero Energy Corporation that provide long-term customer commitments to off-load a total of 140,000 bpd of crude oil at the Pier 400 dock. The ConocoPhillips and Valero agreements are subject to satisfaction of various conditions, such as the achievement of various progress milestones, financing, continued economic viability, and completion of other ancillary agreements related to the project. We are negotiating similar long-term off-loading agreements with other potential customers.

We have failed to meet certain project milestone dates set forth in our Valero agreements, and we are likely to miss other project milestones that are approaching under these agreements. Valero has not given any indication that it will seek to terminate such agreements. We expect that ongoing negotiations with Valero to extend the milestone dates will be successful and that the Valero agreements will remain in effect.

In January 2007, we completed an updated cost estimate for the project. We are estimating that Pier 400, when completed, will cost approximately $360 million, which is subject to change depending on various factors, including: (i) the final scope of the project and the requirements imposed through the permitting process and (ii) changes in construction costs. This cost estimate assumes the construction of 4.0 million barrels of storage. We are in the process of securing the environmental and other permits that will be required for the Pier 400 project from a variety of governmental agencies, including the Board of Harbor Commissioners, the South Coast Air Quality Management District, various agencies of the City of Los Angeles, the Los Angeles City Council and the U.S. Army Corps of Engineers. We expect to have the necessary permits in the first quarter of 2008. Final construction of the Pier 400 project is subject to the completion of a land lease (that will include a dock construction agreement) with the Port of Los Angeles, receipt of environmental and other approvals, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. Subject to timely receipt of approvals, we expect construction of the Pier 400 terminal may be completed and the facility placed in service in 2009 or 2010.

LPG Storage Facilities and Terminals

We own the following LPG storage facilities and terminals:

Storage facilities with the capability of storing approximately 1.7 million barrels of product;

Pipeline terminals consisting of (i) a 130-mile pipeline and terminal that is capable of storing 17,000 barrels of propane, and (ii) a facility that can store 7,000 barrels of propane where product is shipped out via truck; and

Transloading facilities where product is delivered by rail car and shipped out via truck, with approximately 24,000 barrels of operational storage capacity.

We believe these facilities will further support the expansion of our LPG business in Canada and 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.

Natural Gas Storage Assets

We believe strategically located natural gas storage facilities with multi-cycle injection and withdrawal capabilities and access to critical transportation infrastructure will play an increasingly important role in balancing the markets and ensuring reliable delivery of natural gas to the customer during peak demand periods. We believe that our expertise in hydrocarbon storage, our strategically located assets, our financial strength and our commercial experience will enable us to play a meaningful role in meeting the challenges and capitalizing on the opportunities associated with the evolution of the U.S. natural gas storage markets.

Bluewater. The Bluewater gas storage facility, which is located in Michigan, is a depleted reservoir facility with an approximate 23 Bcf of capacity and is also strategically positioned. In April 2006, PAA/Vulcan acquired the Kimball gas storage facility and connected this 2.7 Bcf facility to the Bluewater facility. Natural gas storage facilities in the northern tier of the U.S. are traditionally used to meet seasonal demand and are typically cycled once or twice during a given year. Natural gas is injected during the summer months in order to provide for adequate deliverability during the peak demand winter months. Michigan is a very active market for natural gas storage as it meets nearly 75% of its peak winter demand from storage withdrawals. The Bluewater facility has direct interconnects to four major pipelines and has indirect access to another four pipelines as well as to Dawn, a major natural gas market hub in Canada.

Pine Prairie. The Pine Prairie facility is expected to become partially operational in 2007 and fully operational in 2009, and we believe it is well positioned to benefit from evolving market dynamics. The facility is located near Gulf Coast supply sources and near the existing Lake Charles LNG terminal, which is the largest LNG import facility in the United States. When completed, the Pine Prairie facility is expected to be a 24 Bcf salt cavern storage facility designed for high deliverability operating characteristics and multi-cycle capabilities. The initial phase of the facility will consist of three storage caverns with working capacity of eight Bcf per cavern and an extensive header system. Drilling operations on two of the three cavern wells is complete and drilling operations on the third cavern well commenced in late December 2006. Leaching operations on the first cavern well began in November 2006, construction of the gas handling and compression facilities began in December 2006 and construction on the pipeline interconnects began during January 2007. The site is located approximately 50 miles from the Henry Hub, the delivery point for NYMEX natural gas futures contracts, and is currently intended to interconnect with seven major pipelines serving the Midwest and the East Coast. Three additional pipelines are also located in the vicinity and offer the potential for future interconnects. We believe the facility s operating characteristics and strategic location position Pine Prairie to support the commercial functions of power generators, pipelines, utilities, energy merchants and LNG re-gasification terminal operators and provide potential customers with superior flexibility in managing their price and volumetric risk and balancing their natural gas requirements. In January 2007, an additional 240 acres of land were purchased adjacent to the Pine Prairie project to support future expansion activities.

Marketing

Our marketing segment operations generally consist of the following merchant activities:

- 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 the purchase of foreign cargoes at their load port and various other locations in transit;

- the storage of inventory during contango market conditions;

- the purchase of refined products and LPG from producers, refiners and other marketers;

- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and

- arranging for the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

Our marketing activities are designed to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside exposure to opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to reduce the negative impact of market volatility and provide counter-cyclical balance. 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).

In addition to substantial working inventories and working capital associated with its merchant activities, the marketing segment also employs significant volumes of crude oil and LPG as linefill or minimum inventory requirements under service arrangements with transportation carriers and terminalling providers. The marketing segment also employs trucks, trailers, barges, railcars and leased storage.

As of December 31, 2006, the marketing segment owned crude oil and LPG classified as long-term assets and a variety of owned or leased long-term physical assets throughout the United States and Canada, including:

7.9 million barrels of crude oil and LPG linefill in pipelines owned by the Partnership;

1.5 million barrels of crude oil and LPG linefill in pipelines owned by third parties;

500 trucks and 600 trailers; and

1,300 railcars.

In connection with its operations, the marketing segment secures transportation and facilities services from the Partnership s other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Inter-segment transportation service rates are based on posted tariffs for pipeline transportation services. Facilities segment services are also obtained at rates consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our marketing segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties.

We purchase crude oil and LPG from multiple producers and believe that we generally have established long-term, broad-based relationships with the crude oil and LPG producers in our areas of operations. Marketing activities involve relatively large volumes of transactions, often with lower margins than transportation and facilities operations. Marketing activities for LPG typically consist of smaller volumes per transaction relative to crude oil.

The following table shows the average daily volume of our lease gathering, LPG sales and waterborne foreign crude imported for the past five years:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(Barrels in thousands)				
Crude oil lease gathering	650	610	589	437	410
LPG sales	70	56	48	38	35
Waterborne foreign crude imported	63	59	12		
Total volumes per day	783	725	649	475	445

Crude Oil and LPG Purchases. We purchase crude oil in North America from producers under contracts, the majority of which range in term from a thirty-day evergreen to three-year term. We utilize our truck fleet and gathering pipelines as well as third party pipelines, trucks and barges to transport the crude oil to market. In addition, we purchase foreign crude oil. Under these contracts we may purchase crude oil upon delivery in the U.S. or we may purchase crude oil in foreign locations and transport crude oil on third-party tankers.

We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that range from immediate delivery to one year in term. We utilize leased railcars and third party tank truck or pipelines to transport LPG.

In addition to purchasing crude oil from producers, we purchase both domestic and foreign crude oil in bulk at major pipeline terminal locations and barge facilities. 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 crude oil and LPG in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or 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.

Crude Oil and LPG Sales. The marketing of crude oil and LPG is complex and requires current detailed knowledge of crude oil and LPG 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, location of customers, various modes and availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil and LPG 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 sell LPG primarily to retailers and refiners, and limited volumes to other marketers. We establish a margin for crude oil and LPG we purchase by sales for physical delivery to third party users, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX, IntercontinentalExchange (ICE) or over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil and LPG 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 and LPG-related futures contracts as hedging devices.

Crude Oil and LPG Exchanges. We pursue exchange opportunities to enhance margins throughout the gathering and marketing process. When opportunities arise to increase our margin or to acquire a grade, type or volume of crude oil or LPG that more closely matches our physical delivery requirement, location or the preferences of our customers, we exchange physical crude oil or LPG, as appropriate, 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 or LPG that differs in terms of geographic location, grade of crude oil or type of LPG, or physical delivery schedule from crude oil or LPG we have available for sale. Generally, we enter into exchanges to acquire crude oil or LPG 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. See Note 2 to our Consolidated Financial Statements.

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, to a lesser extent, 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, 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.

Crude Oil Volatility; Counter-Cyclical Balance; Risk Management

Crude oil commodity prices have historically been very volatile and cyclical. For example, NYMEX WTI crude oil benchmark prices have ranged from a high of over $78 per barrel (July 2006) to a low of $10 per barrel (March 1986) over the last 20 years. Segment profit from our facilities activities is dependent on 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 marketing activities is dependent on our ability to sell crude oil and LPG at prices in excess of our aggregate cost. Although margins may be affected during transitional periods, our crude oil marketing 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 in the near term, 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 our lease gathering margins, but is favorable to our commercial strategies that are associated with storage tankage leased from the facilities segment or from third parties. Those who control storage 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 our lease gathering 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 marketing segment. When the market is in contango, we will use our tankage to improve our lease 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 lease gathering margins provide an offset to this reduced cash flow. We believe that the combination of our lease gathering activities and the commercial strategies used with our tankage provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities in an effort to maintain a base level of margin irrespective of crude oil market conditions and, in certain circumstances, to realize incremental margin during volatile market conditions. References to counter-cyclical balance elsewhere in this report are referring to this relationship between our facilities activities and our 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 and ICE futures contracts and derivatives, have become increasingly important in creating and maintaining margins. In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations (mainly relating to crude oil) and, in certain circumstances, to realize incremental margin during volatile market conditions, 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. Our risk management policies and procedures are designed to monitor NYMEX, ICE 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 risk management function also approves all new risk management strategies through a formal process. With the exception of the controlled trading program discussed below, 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.

Our policy is generally to purchase only product for which we have a market, and to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive. Except for the controlled crude oil trading program discussed below, we do not acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on commodity price changes as these activities could expose us to significant losses.

Although 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. Such amounts exclude unhedged working inventory volumes that remain relatively constant and are subject to lower of cost or market adjustments.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. This could be the result of a derivative that is an effective element of our risk management strategy that may not be sufficiently effective to qualify for hedge accounting or a derivative that is disallowed hedge accounting treatment under SFAS 133 due to the uncertainty of physical delivery. Additionally, certain elements of our risk management strategies such as the time value of options do not qualify for hedge accounting under SFAS 133 whether effective or not. In such instances, changes in the fair values of derivatives that do not qualify or are excluded from hedge accounting 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 15 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Company, LLC (Marathon) accounted for 14%, 11% and 10% of our revenues for each of the three years in the period ended December 31, 2006. Valero Marketing & Supply Company (Valero) accounted for 10% of our revenues for the year ended December 31, 2006. BP Oil Supply accounted for 14% and 10% of our revenues for the years ended December 31, 2005 and 2004, respectively. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of revenues from Marathon, Valero and BP Oil Supply pertain to our marketing 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 also face competition in our marketing services and facilities services. 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 laws and regulations. We are subject to regulatory oversight by numerous 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 laws 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, you should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

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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 s (DOT) Pipeline and Hazardous Materials Safety Administration with respect to the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations. Regulation in Canada is under the National Energy Board (NEB) and provincial agencies. 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. U.S. Federal pipeline safety rules also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities.

In 2001, the DOT adopted the initial pipeline integrity management rule, which required operators of jurisdictional pipelines transporting hazardous liquids 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. In December 2003, the DOT issued a final rule requiring natural gas pipeline operators to develop similar integrity management programs for gas transmission pipelines located in high consequence areas. Segments of our pipelines transporting hazardous liquids and/or natural gas 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 $8.2 million in 2006, $4.7 million in 2005 and approximately $5 million in 2004. Based on currently available information, our preliminary estimate for 2007 is approximately $10.5 million. The relative increase in program cost over the last few years is primarily attributable to pipeline segments acquired in recent years (including the Pacific and Link assets), which are subject to the rules. 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. 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.

In September 2006, the DOT published a Notice of Proposed Rulemaking (NPRM) that proposed to regulate certain hazardous liquid gathering and low stress pipeline systems that are not currently subject to regulation. On December 6, 2006, the Congress passed, and on December 29, 2006 President Bush signed into law, H.R. 5782, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Pipeline Safety Act), which reauthorizes and amends the DOT s pipeline safety programs. Included in the 2006 Pipeline Safety Act is a provision eliminating the regulatory exemption for hazardous liquid pipelines operated at low stress, which was one of the focal points of the September 2006 NPRM. The Act requires DOT to issue regulations by December 31, 2007 for those hazardous liquid low stress pipelines now subject to regulation pursuant to the 2006 Pipeline Safety Act. Regulations issued by December 31, 2007 with respect to hazardous liquid low stress pipelines as well as any future regulation of hazardous liquid gathering lines could include requirements for the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact these developments will have on our operating expenses and, thus, cannot provide any assurances that future costs related to these programs will not be material.

In addition to performing DOT-mandated pipeline integrity evaluations, during 2006, we expanded an internal review process started in 2005 in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rule. The purpose of this process is to review the surrounding environment, condition and operating history of these pipelines and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we could be required (as a result of additional DOT regulation) or we may elect (as a result of our own internal initiatives) 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 79% of our 60 million barrels are subject to DOT jurisdiction). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required in 2009. Costs associated with this program were approximately $6.8 million, $4.4 million and $3 million in 2006, 2005 and 2004, respectively. Based on currently available information, we anticipate we will spend an approximate average of $15.7 million per year from 2007 through 2009 in connection with API 653 compliance activities. In some cases, we may take storage tanks out of service if we believe the cost of upgrades will exceed the value of the storage tanks or construct replacement tankage at a more optimal location. 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 provide any assurance 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 Saskatchewan Industry and Resources regulate the construction, alteration, inspection and repair of crude oil storage tanks. We expect to incur costs under laws and 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. We spent approximately $4.5 million in 2006, $4.9 million in 2005 and $4.1 million in 2004 on compliance activities. Our preliminary estimate for 2007 is approximately $6.9 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. 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 include both crude oil pipelines and refined products 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, including the California Public Utility Commission, which prohibits certain of our subsidiaries from acting as guarantors of our senior notes and credit facilities. See Note 12 to our Consolidated Financial Statements.

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial authorities, such as the Alberta Energy and Utilities Board. With respect to a pipeline over which it has jurisdiction, the relevant regulatory authority 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 authority determines that the applicable terms and conditions of service are not just and reasonable, the regulatory authority can impose conditions it considers appropriate.

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. Specifically, the indexing methodology allows a pipeline to increase its rates annually by a percentage equal to the change in the producer price index for finished goods (PPI-FG) plus 1.3% to the new ceiling level. 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 PPI-FG falls and 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 FERC s indexing methodology is subject to review every five years; the current methodology is expected to remain in place through June 30, 2011. If the FERC continues its policy of using the PPI-FG plus 1.3%, changes in that index might not fully reflect actual increases in the costs associated with the pipelines subject to indexing, thus hampering our ability to recover cost increases.

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 certain 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 (or MLP) 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 May 4, 2005, the FERC adopted a policy statement in Docket No. PL05-5 (Policy Statement), stating that it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities cost-of-service rates to reflect the actual or potential income tax liability attributable to their public utility income, regardless of the form of ownership. Pursuant to the Policy Statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity s public utility income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, such as MLPs, it still entails rate risk due to the case-by-case review requirement. The new tax allowance policy has been appealed to the D.C. Circuit. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC s treatment of income tax allowances in cost of service. FERC continues to refine its tax allowance policy in case-by-case reviews; how the policy statement on income tax allowances is applied in practice to pipelines owned by MLPs, and whether it is ultimately upheld or modified on judicial review, could affect the rates of FERC regulated pipelines.

Additionally, the criteria for establishing substantially changed circumstances under EPAct, among other issues, are currently under review by the D.C. Circuit. Oral argument was held on December 12, 2006, but the court has not yet issued an opinion. We have no way of knowing what effect, if any, action by the FERC and/or the D.C. Circuit on this issue and others might have on our 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 in our transportation segment 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 DOT. 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 training and certification, facility inspection, reporting and safety.

Cross Border Regulation

As a result of our Canadian acquisitions and cross border activities, including importation of crude oil into the United States, we are subject to a variety of legal requirements pertaining to such activities including export/import license requirements, tariffs, Canadian and U.S. customs and taxes and requirements relating to toxic substances. U.S. legal requirements relating to these activities include regulations adopted pursuant to 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 or failure to provide certifications relating to toxic substances 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.

Natural Gas Storage Regulation

Interstate Regulation. The interstate storage facilities in which we have an investment are or will be subject to rate regulation by the FERC under the Natural Gas Act. The Natural Gas Act requires that tariff rates for gas storage facilities be just and reasonable and non-discriminatory. The FERC has authority to regulate rates and charges for natural gas transported and stored for U.S. interstate commerce or sold by a natural gas company via interstate commerce for resale. The FERC has granted market-based rate authority under its existing regulations to PAA/Vulcan s Pine Prairie Energy Center, which is under construction in Louisiana, and to its Bluewater gas storage facility.

The FERC also has authority over the construction and operation of U.S. transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. Absent an exemption granted by the FERC, FERC s Standard of Conduct regulations restricted access to U.S. interstate natural gas storage customer data by marketing and other energy affiliates, and placed certain conditions on services provided by the U.S. storage facility operators to their affiliated gas marketing entities. Pine Prairie Energy Center elected to adhere to the Standards of Conduct regulations. However, the Standards of Conduct did not apply to natural gas storage providers authorized to charge market-based rates that are not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline, have no exclusive franchise area, no captive ratepayers, and no market power. The FERC has found that PAA/Vulcan s Pine Prairie Energy Center and its Bluewater facility qualified for this exemption from the Standards of Conduct.

On November 17, 2006, the D.C. Circuit vacated the Standards of Conduct regulations with respect to natural gas pipelines, and remanded the matter to FERC. On January 9, 2007, FERC issued an interim Standards of Conduct rule that reimposed certain of the Standards of Conduct regulations on interstate natural gas transmission providers while narrowing the regulations in a manner that FERC believes is in compliance with the D.C. Circuit s remand. The interim rule continues to exempt natural gas storage providers like PAA/Vulcan s Pine Prairie Energy Center and its Bluewater facility. On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking for new Standards of Conduct regulations. Under the proposed rule, the Standards of Conduct would continue to exempt natural gas storage providers like PAA/Vulcan s Pine Prairie Energy Center and its Bluewater facility. We are unable to predict what Standards of Conduct regulations FERC will ultimately adopt, or whether those regulations will withstand judicial review.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005 (EPAct 2005). Among other matters, EPAct 2005 amends the Natural Gas Act to add an antimanipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC. On January 19, 2006, the FERC issued Order No. 670, a rule implementing the antimanipulation provision of EPAct 2005. The rules make it unlawful in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new antimanipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. EPAct 2005 also amends the Natural Gas Act and the Natural Gas Policy Act to give FERC authority to impose civil penalties for violations of the Natural Gas Act up to $1,000,000 per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. The antimanipulation rule and enhanced civil penalty authority reflect an expansion of FERC s Natural Gas Act enforcement authority. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. The natural gas industry historically has been heavily regulated. Accordingly, we cannot assure you that the less stringent and pro-competition regulatory approach recently pursued by FERC and Congress will continue.

State Regulation. The intrastate storage facilities in which we have an investment are also subject to regulation by the Michigan State Public Service Commission. Specifically, the Michigan State Public Service Commission has authority to regulate our storage facilities in Michigan with respect to safety and environmental matters.

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 resulting in more stringent requirements, 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 any claims made by neighboring landowners and other third parties for personal injury and natural resource and property damage.

Water

The U.S. Oil Pollution Act (OPA) subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. The OPA establishes a liability limit of $209 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. State and Canadian federal and provincial laws also impose requirements relating to the prevention of oil releases and the remediation of areas affected by releases when they occur. We believe that we are in substantial compliance with all such state and Canadian requirements.

The U.S. Clean Water Act and 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. See Note 11 to our Consolidated Financial Statements. Permits or approvals 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 or approval 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 and provincial 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 releases, 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 and operating expenditures in the next several years for installing air pollution control equipment and otherwise complying with more stringent state and regional air emissions control plans in connection with obtaining or maintaining permits and approvals for sources of air emissions. Although 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.

Further, in response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth s atmosphere, many foreign nations, including Canada, have agreed to limit emissions of these gases, generally referred to as greenhouse gases, pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. The Kyoto Protocol requires Canada to reduce its emissions of greenhouse gases to 6% below 1990 levels by 2012. As a result, it is possible that already stringent air emissions regulations applicable to our operations in Canada will be replaced with even stricter requirements prior to 2012. Although the United States is not participating in the Kyoto Protocol, the current session of Congress is considering climate change-related legislation, with multiple bills having already been introduced in the Senate that propose to restrict greenhouse gas emissions. Also, several states have adopted legislation, regulations and/or regulatory initiatives to reduce emissions of greenhouse gases. For instance, California recently adopted the California Global Warming Solutions Act of 2006, which requires the California Air Resources Board to achieve a 25% reduction in emissions of greenhouse gases from sources in California by 2020. Additionally, on November 29, 2006, the U.S. Supreme Court heard arguments on a case appealed from the U.S. Circuit Court of Appeals for the District of Columbia, *Massachusetts, et al. v. EPA*, in which the appellate court held that the EPA had discretion under the federal Clean Air Act to refuse to regulate carbon dioxide emission from mobile sources. Passage of climate control legislation by Congress or a Supreme Court reversal of the appellate decision could result in federal regulation of carbon dioxide emissions and other greenhouse gases. Any federal, provincial or state restrictions on emissions of greenhouse gases that may be imposed in areas of the United States in which we conduct business or in Canada prior to 2012 could adversely affect our operations and demand for our products.

Solid Waste

We generate wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act (RCRA) and 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 oil and gas wastes may be included as RCRA hazardous wastes, 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 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. Canadian and provincial laws also impose liabilities for releases of certain substances into the environment. 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, under the Criminal Code of Canada, organizations, corporations and individuals may be prosecuted criminally for violating the duty to protect employee and public safety. We believe that our operations are in substantial compliance with applicable occupational health and safety 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 operational 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. Legislation in Canada for the protection of species at risk and their habitat (the Species at Risk Act) applies to our Canadian operations.

Hazardous Materials Transportation Requirements

The federal and analogous state 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 state and Canadian federal and provincial laws and regulations. Under such laws and regulations, 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.

For instance, in connection with the purchase of assets from Link in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of $20 million. 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 agreed to bear $11 million of the first $20 million of pre-May 1999 environmental issues. We also agreed to 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 agreed to pay all costs in excess of $20 million (excluding the deductible for new sites). TNM s obligations are guaranteed by Shell Oil Products (SOP). As of December 31, 2006, we had incurred approximately $7 million of remediation costs associated with these sites; SOP s share is approximately $1.5 million.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, SOP 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. SOP made a claim against the policy; however, we do not believe that the claim substantially reduced 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 that occurred prior to the date of the closing of the acquisition. Other than with respect to liabilities associated with two Superfund sites at which it is alleged that Scurlock deposited waste oils, this indemnity has expired or was terminated by agreement.

As a result of our merger with Pacific, we have assumed liability for a number of ongoing remediation sites, associated with releases from pipeline or storage operations. These sites had been managed by Pacific prior to the merger, and in general there is no insurance or indemnification to cover ongoing costs to address these sites (with the exception of the Pyramid Lake crude oil release, which is discussed in Item 3. Legal Proceedings). We have evaluated each of the sites requiring remediation, through review of technical and regulatory documents, discussions with Pacific, and our experience at investigating and remediating releases from pipeline and storage operations. We have developed reserve estimates for the Pacific sites based on this evaluation, including determination of current and long-term reserve amounts, which total approximately $21.8 million.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified.

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil or petroleum products into the environment from our pipeline and storage operations. We also may discover environmental impacts from 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. As we expand our pipeline assets through acquisitions, we typically improve on (decrease) the rate of releases from such assets as we implement our standards and procedures, remove selected assets from service and spend capital to upgrade the assets. In the immediate post-acquisition period, however, the inclusion of additional miles of pipe in our operation may result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the Link acquisition, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations. See Item 3. Legal Proceedings.

At December 31, 2006, our reserve for environmental liabilities totaled approximately $39.1 million (approximately $21.8 million of this reserve is related to liabilities assumed as part of the Pacific merger, and $10.4 million is related to liabilities assumed as part of the Link acquisition). Approximately $19.5 million of our environmental reserve is classified as current and $19.6 million is classified as long-term. At December 31, 2006, we have recorded receivables totaling approximately $11.6 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. 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, although we believe that the reserve is adequate, 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 1,300% 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. The overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. Some of this may be attributable to the events of September 11, 2001, which adversely impacted the availability and costs of certain types of coverage. Certain aspects of these conditions were further exacerbated by the hurricanes along the Gulf Coast during 2005, which also had an adverse effect on the availability and cost of coverage. 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. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies. 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 is 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 subsequently granted by 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 and Labor Relations

To carry out our operations, our general partner or its affiliates (including PMC (Nova Scotia) Company) employed approximately 2,900 employees at December 31, 2006. None of the employees of our general partner were subject to a collective bargaining agreement, except for nine employees at our Paulsboro, New Jersey terminal, who are members of USW District 10-286 (Steel Workers), with whom we have a collective bargaining agreement that will end on October 1, 2009. 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 considerations of owning and disposing of common units.

Partnership Status; Cash Distributions

We are treated 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 U.S. 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. In certain cases, we are subject to, or have paid Canadian income and withholding taxes. Canadian withholding taxes are due on intercompany interest payments and credits and dividend payments.

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. In determining a unitholder s federal income tax liability, the unitholder is required to take into account the unitholder s share of income generated by us for each taxable year of the Partnership ending with or within 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 and the unitholder s share of our nonrecourse liabilities. A unitholder s basis is generally increased by the unitholder s share of our income and by any increases in the unitholder s share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by the unitholder s share of our losses and distributions (including deemed distributions due to a decrease in the unitholder s share of our nonrecourse liabilities).

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 taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, a unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

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 conduct business or own property. We own property and conduct business in Canada as well as in most states in the United States. A unitholder will therefore be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes in respect of our Canadian source income earned through partnership entities. A unitholder may also be required to file state income tax returns and to pay taxes in various states. A unitholder may be subject to interest and 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 a particular state, may not relieve the unitholder from the obligation to file an income tax return in that state. 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) 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. 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.

Available Information

We make available, free of charge on our Internet website (http://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.

Item 1A. *Risk Factors*

Risks Related to 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 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 under futures contracts on the NYMEX, ICE 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 physical inventory, futures contracts or derivative products for the purpose of speculating on commodity price changes. These policies and practices 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. We are also exposed to basis risk when crude oil is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on certain of our inventory, such as 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.

The nature of our business and assets exposes us to significant compliance costs and liabilities. Our asset base has more than tripled within the last three years. We have experienced a corresponding increase in the relative number of releases of crude oil to the environment. Substantial expenditures may be required to maintain the integrity of aged and aging pipelines and terminals at acceptable levels.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil and refined products, as well as our operations involving the storage of natural gas, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment, operational safety and related matters. Compliance with all of these laws and regulations increases our overall cost of doing 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, the issuance of injunctions that may restrict or prohibit our operations, or claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change and interpretation by the relevant governmental agency. Any such

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change or interpretation adverse to us could have a material adverse effect on our operations, revenues and profitability.

Today we own approximately three times the miles of pipeline we owned three years ago. As we have expanded our pipeline assets, we have observed a corresponding increase in the number of releases of crude oil to the environment. These releases expose us to potentially substantial expense, including clean-up and remediation costs, fines and penalties, and third party claims for personal injury or property damage related to past or future releases. Some of these expenses could increase by amounts disproportionately higher than the relative increase in pipeline mileage and the increase in revenues associated therewith. During 2006, we entered the refined products pipeline and terminalling businesses through the acquisition of three products pipeline systems in West Texas and New Mexico and through the acquisition of Pacific, which had refined product assets in California, the U.S. Rockies and Pennsylvania. These businesses are also subject to significant compliance costs and liabilities. In addition, because of their increased volatility and tendency to migrate farther and faster than crude oil, releases of refined products into the environment can have more significant impact than crude oil and require significantly higher expenditures to respond and remediate. The incurrence of such expenses not covered by insurance, indemnity or reserves could materially adversely affect our results of operations.

We currently spend substantial amounts to comply with DOT-mandated pipeline integrity rules. The 2006 Pipeline Safety Act, enacted in December 2006, requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. These regulations could include requirements for the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact this will have on our operating expenses.

In addition to performing DOT-mandated pipeline integrity evaluations, during 2006, we expanded an internal review process started in 2005 pursuant to which we review various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rules. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we could be required (as a result of additional DOT regulation) or we may elect (as a result of our own internal initiatives) 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.

Loss of credit rating or the ability to receive open credit could negatively affect our ability to use the counter-cyclical aspects of our asset base or to capitalize on a volatile market.

We believe that, because of our strategic asset base and complementary business model, we will continue to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market. Our ability to capture that benefit, however, is subject to numerous risks and uncertainties, including our maintaining an attractive credit rating and continuing to receive open credit from our suppliers and trade counter-parties.

We may not be able to fully implement or capitalize upon planned growth projects.

We have a number of organic growth projects that require the expenditure of significant amounts of capital, including the Pier 400 project, the Salt Lake City expansion, the Cheyenne pipeline project, the Pine Prairie joint venture and the St. James, Cushing and Patoka terminal projects. Many of these projects involve numerous regulatory, environmental, weather-related, political and legal uncertainties that will be beyond our control. As these projects are undertaken, required approvals may not be obtained, may be delayed or may be obtained with conditions that materially alter the expected return associated with the underlying projects. Moreover, revenues associated with these organic growth projects will not increase immediately upon the expenditures of funds with respect to a particular project and these projects may be completed behind schedule or in excess of budgeted cost. Because of continuing increased demand for materials, equipment and services, there could be shortages and cost increases associated with construction projects. We may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes. As a result of these uncertainties, the anticipated benefits associated with our capital projects may not be achieved.

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. A shut-in of this production due to economic limitations or a significant event could adversely affect our profitability. In addition, these offshore fields have 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 and the onshore fields in the San Joaquin Valley. 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 transportation segment profit of approximately $6.1 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated $3.2 million decrease in annual transportation segment profit. In addition, any significant production disruption from the outer continental shelf fields and the San Joaquin Valley due to production problems, transportation problems or other reasons could have a material adverse effect on our business.

Our profitability depends on the volume of crude oil, refined product and LPG shipped, purchased and gathered.

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 8% volume variance on that system, would change annualized segment profit by approximately $1.3 million.

To maintain the volumes of crude oil we purchase in connection with our operations, 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 relationships already exist 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 $2.7 million per year negative impact on segment profit. This impact assumes 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 estimate that a $0.01 variance in the average segment profit per barrel would have an approximate $4.2 million annual effect on segment profit.

Fluctuations in demand can negatively affect our operating results.

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.

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.

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

Our ability to grow depends in part 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 we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with the sellers, (ii) unable to raise financing for such acquisitions on economically acceptable terms or (iii) outbid by competitors, our future growth will be limited. In particular, competition for midstream assets and businesses has intensified substantially and as a consequence 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 that increase our cost of capital could impair our ability to grow through acquisitions.

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 affect 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;
- risks associated with operating in lines of business that are distinct and separate from our historical operations;
- 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.

Our pipeline assets are subject to federal, state and provincial regulation. Rate regulation or a successful challenge to the rates we charge on our domestic interstate pipeline system may reduce the amount of cash we generate.

Our domestic interstate common carrier pipelines are subject to regulation by the 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 DOT. Our intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

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The EPAct, among other things, deems just and reasonable within the meaning of the Interstate Commerce Act any oil pipeline rate in effect for the 365-day period ending on the date of the enactment of EPAct if the rate in effect was not subject to protest, investigation, or complaint during such 365-day period. (That is, the EPAct grandfathers any such rates.) The EPAct further protects any rate meeting this requirement from complaint unless the complainant can show that a substantial change occurred after the enactment of EPAct in the economic circumstances of the oil pipeline which were the basis for the rate or in the nature of the services provided which were a basis for the rate. This grandfathering protection does not apply, under certain specified circumstances, when the person filing the complaint was under a contractual prohibition against the filing of a complaint.

For our domestic interstate common carrier pipelines subject to FERC regulation under the Interstate Commerce Act, shippers may protest our pipeline tariff filings, and the FERC may investigate new or changed tariff rates. Further, other than for rates set under market-based rate authority and for rates that remain grandfathered under EPAct, the FERC may order refunds of amounts collected under rates that were in excess of a just and reasonable level when taking into consideration the pipeline system s cost of service. In addition, shippers may challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint. The FERC s ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs.

The potential for a challenge to the status of our grandfathered rates under EPAct (by showing a substantial change in circumstances) or a challenge to our indexed rates creates the risk that the FERC might find some of our rates to be in excess of a just and reasonable level that is, a level justified by our cost of service. In such an event, the FERC could order us to reduce any such rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

Our Canadian pipelines are subject to regulation by the NEB or by provincial authorities. Under the National Energy Board Act, the NEB could investigate the tariff rates or the terms and conditions of service relating to a jurisdictional pipeline on its own initiative upon the filing of a toll or tariff application, or upon the filing of a written complaint. If it found the rates or terms of service relating to such pipeline to be unjust or unreasonable or unjustly discriminatory, the NEB could require us to change our rates, provide access to other shippers, or change our terms of service. A provincial authority could, on the application of a shipper or other interested party, investigate the tariff rates or our terms and conditions of service relating to our provincially regulated proprietary pipelines. If it found our rates or terms of service to be contrary to statutory requirements, it could impose conditions it considers appropriate. A provincial authority could declare a pipeline to be a common carrier pipeline, and require us to change our rates, provide access to other shippers, or otherwise alter our terms of service. Any reduction in our tariff rates would result in lower revenue and cash flows.

Some of our operations cross the U.S./Canada border and are subject to cross border regulation.

Our cross border activities with our Canadian subsidiaries subject us to regulatory matters, including import and 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 licensing, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties.

We face competition in our transportation, facilities and marketing activities.

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

With respect to our natural gas storage operations, we compete with other storage providers, including local distribution companies (LDCs), utilities and affiliates of LDCs and utilities. Certain major pipeline companies have existing storage facilities connected to their systems that compete with certain of our facilities. Third-party construction of new capacity could have an adverse impact on our competitive position.

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

There can be no assurance that we have adequately assessed the creditworthiness of our existing or future counterparties or that there will not be an unanticipated deterioration in their creditworthiness, 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.

We may in the future encounter increased costs related to, and lack of availability of, insurance.

Over the last several years, as the scale and scope of our business activities has expanded, the breadth and depth of available insurance markets has contracted. Some of this may be attributable to the events of September 11, 2001 and the effects of hurricanes along the Gulf Coast during 2005, which adversely impacted the availability and costs of certain types of coverage. We can give no assurance that we will be able to maintain adequate insurance in the future at rates we consider reasonable. The occurrence of a significant event not fully insured could materially and adversely affect our operations and financial condition.

Marine transportation of crude oil and refined product has inherent operating risks.

Our gathering and marketing operations include purchasing crude oil that is carried on third-party tankers. Our waterborne cargoes of crude oil are at risk of being damaged or lost because of events such as marine disaster, bad weather, mechanical failures, grounding or collision, fire, explosion, environmental accidents, piracy, terrorism and political instability. Such occurrences could result in death or injury to persons, loss of property or environmental damage, delays in the delivery of cargo, loss of revenues from or termination of charter contracts, governmental fines, penalties or restrictions on conducting business, higher insurance rates and damage to our reputation and customer relationships generally. Although certain of these risks may be covered under our insurance program, any of these circumstances or events could increase our costs or lower our revenues.

In instances in which cargoes are purchased FOB (title transfers when the oil is loaded onto a vessel chartered by the purchaser) the contract to purchase is typically made prior to the vessel being chartered. In such circumstances we take the risk of higher than anticipated charter costs. We are also exposed to increased transit time and unanticipated demurrage charges, which involve extra payment to the owner of a vessel for delays in offloading, circumstances that we may not control.

Maritime claimants could arrest the vessels carrying our cargoes.

Crew members, suppliers of goods and services to a vessel, other shippers of cargo and other parties may be entitled to a maritime lien against that vessel for unsatisfied debts, claims or damages. In many jurisdictions, a maritime lienholder may enforce its lien by arresting a vessel through foreclosure proceedings. The arrest or attachment of a vessel carrying a cargo of our oil could substantially delay our shipment.

In addition, in some jurisdictions, under the sister ship theory of liability, a claimant may arrest both the vessel that is subject to the claimant s maritime lien and any associated vessel, which is any vessel owned or controlled by the same owner. Claimants could try to assert sister ship liability against one vessel carrying our cargo for claims relating to a vessel with which we have no relation.

We are dependent on use of a third-party marine dock for delivery of waterborne crude oil into our storage and distribution facilities in the Los Angeles basin.

A portion of our storage and distribution business conducted in the Los Angeles basin (acquired in connection with the Pacific acquisition) is dependent on our ability to receive waterborne crude oil, a major portion of which is presently being received through dock facilities operated by Shell Oil Products in the Port of Long Beach. We are currently a hold-over tenant with respect to such facilities. If we are unable to renew the agreement that allows us to utilize these dock facilities, and if other alternative dock access cannot be arranged, the volumes of crude oil that we presently receive from our customers in the Los Angeles basin may be reduced, which could result in a reduction of facilities segment revenue and cash flow.

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

As of December 31, 2006, our total outstanding long-term debt was approximately $2.6 billion. Various limitations in certain of our debt instruments 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.

Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets, specifically the nation s pipeline infrastructure, may be future targets of terrorist organizations. These developments will subject our operations to increased risks. Any future terrorist attack that may target our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

An impairment of goodwill could reduce our earnings.

We recorded a significant amount of goodwill upon completion of our merger with Pacific, but our preliminary estimate is subject to change pending the completion of an independent appraisal. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the acquired tangible and separately measurable intangible net assets. U.S. generally accepted accounting principles, or GAAP, requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If we were to determine that any of our remaining balance of goodwill was impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners equity and increase in balance sheet leverage as measured by debt to total capitalization.

Our natural gas storage facilities are new and have limited operating history.

Although we believe that our operating natural gas storage facilities are designed substantially to meet our contractual obligations with respect to injection and withdrawal volumes and specifications, the facilities are new and have a limited operating history. If we fail to receive or deliver natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, we could incur significant costs to maintain compliance with our contracts.

We have a limited history of operating natural gas storage facilities and transporting, storing and marketing refined products.

Although many aspects of the natural gas storage and refined products industries are similar to our crude oil operations, our current management has little experience in operating natural gas storage facilities or in the refined products business. There are significant risks and costs inherent in our efforts to engage in these operations, including the risk that our new lines of business may not be profitable and that we might not be able to operate them or implement our operating policies and strategies successfully.

The devotion of capital, management time and other resources to natural gas storage and refined products operations could adversely affect our existing business. Entering into the natural gas storage and refined products industries may require substantial changes, including acquisition costs, capital development expenditures, adding skilled management and employees and realigning our current organization to reflect these new lines of business.

Entering into the natural gas storage industry will require an investment in personnel and assets and the assumption of risks that may be greater than we have previously assumed.

Federal, state or local regulatory measures could adversely affect our natural gas storage business.

Our natural gas storage operations are subject to federal, state and local regulation. Specifically, our natural gas storage facilities and related assets are subject to regulation by the FERC, the Michigan Public Service Commission and various Louisiana state agencies. Our facilities essentially have market-based rate authority from such agencies. Any loss of market-based rate authority could have an adverse impact on our revenues associated with providing storage services. In addition, failure to comply with applicable regulations under the Natural Gas Act, and certain other state laws could result in the imposition of administrative, civil and criminal remedies.

Our gas storage business depends on third party pipelines to transport natural gas.

We depend on third party pipelines to move natural gas for our customers to and from our facilities. Any interruption of service on the pipelines or lateral connections or adverse change in the terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport natural gas to and from our facilities, and could have a corresponding material adverse effect on our storage revenues. In addition, the rates charged by the interconnected pipeline for transportation to and from our facilities could affect the utilization and value of our storage services. Significant changes in the rates charged by the pipeline or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our storage revenues.

We may not be able to retain existing natural gas storage customers or acquire new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain or exceed current or anticipated revenues and cash flows depends on a number of factors beyond our control, including competition from other storage providers and the supply of and demand for natural gas in the markets we serve. The inability to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

Joint venture structures can create operational difficulties.

Our natural gas storage operations are conducted through PAA/Vulcan, a joint venture between us and a subsidiary of Vulcan Capital. We are also engaged in a joint venture arrangement with Settoon Towing.

As with any joint venture arrangement, differences in views among the joint venture participants may result in delayed decisions or in failures to agree on major matters, potentially adversely affecting the business and operations of the joint ventures and in turn our business and operations.

Risks Inherent in an Investment in Plains All American Pipeline, L.P.

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

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

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.

Unitholders may not be able to remove our general partner even if they wish to do so.

Our general partner manages and operates the Partnership. Unlike the holders of common stock in a corporation, unitholders will have only limited voting rights on matters affecting our business. Unitholders have no right to elect the general partner or the directors of the general partner on an annual or any other basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 662/3% of our outstanding units (including units held by our general partner or its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders ability to influence the manner or direction of management.

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

We may issue additional common units without unitholder approval, which would dilute a unitholder s existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units, without unitholder approval (subject to applicable NYSE rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without unitholder approval (subject to applicable NYSE rules). The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- an existing unitholder s proportionate ownership interest in the Partnership will decrease;

- the amount of cash available for distribution on each unit may decrease;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the common units may decline.

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

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

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner.

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

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

- we do not have any employees and we rely solely on employees of the general partner or, in the case of Plains Marketing Canada, employees of PMC (Nova Scotia) Company;

- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;

- the amount of cash expenditures, borrowings and reserves in any quarter may affect available cash to pay quarterly distributions to unitholders;

- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner s liability; under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arms length negotiations; and

- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

The control of our general partner may be transferred to a third party without unitholder consent. A change of control may result in defaults under certain of our debt instruments and the triggering of payment obligations under compensation arrangements.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the general partner of our general partner from transferring its general partnership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers with its own choices and to control their decisions and actions.

In addition, a change of control would constitute an event of default under the indentures governing certain issues of our senior notes and under our revolving credit agreement. An event of default under certain of our indentures could require us to make an offer to purchase the senior notes issued thereunder at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any, to the date of purchase. During the continuance of an event of default under our revolving credit agreement, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us under our revolving credit facility and/or declare all amounts payable by us under our revolving credit facility immediately due and payable. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

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Risks Related to an Investment in Our Debt Securities

The right to receive payments on our outstanding debt securities and subsidiary guarantees is unsecured and will be effectively subordinated to our existing and future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the notes.

Our debt securities are effectively subordinated to claims of our secured creditors and the guarantees are effectively subordinated to the claims of our secured creditors as well as the secured creditors of our subsidiary guarantors. Although substantially all of our operating subsidiaries, other than minor subsidiaries and those regulated by the CPUC, have guaranteed such debt securities, the guarantees are subject to release under certain circumstances, and we may have subsidiaries that are not guarantors. In that case, the debt securities would be effectively subordinated to the claims of all creditors, including trade creditors and tort claimants, of our subsidiaries that are not guarantors. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary that is not a guarantor, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of the debt securities.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

Our leverage is significant in relation to our partners capital. At December 31, 2006, our total outstanding long-term debt and short-term debt under our revolving credit facility was approximately $3.6 billion. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facilities 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.

Our leverage could have important consequences to investors in our debt securities. We will require substantial cash flow to meet our principal and interest obligations with respect to the notes and our other consolidated indebtedness. Our ability to make scheduled payments, to refinance our obligations with respect to our indebtedness or our ability to obtain additional financing in the future will depend on our financial and operating performance, which, in turn, is subject to prevailing economic conditions and to financial, business and other factors. We believe that we will have sufficient cash flow from operations and available borrowings under our bank credit facility to service our indebtedness, although the principal amount of the notes will likely need to be refinanced at maturity in whole or in part. However, a significant downturn in the hydrocarbon industry or other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or portion of our debt or sell assets. We can give no assurance that we would be able to refinance our existing indebtedness or sell assets on terms that are commercially reasonable. In addition, if one or more rating agencies were to lower our debt ratings, we could be required by some of our counterparties to post additional collateral, which would reduce our available liquidity and cash flow.

Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

A court may use fraudulent conveyance considerations to avoid or subordinate the subsidiary guarantees.

Various applicable fraudulent conveyance laws have been enacted for the protection of creditors. A court may use fraudulent conveyance laws to subordinate or avoid the subsidiary guarantees of our debt securities issued by any of our subsidiary guarantors. It is also possible that under certain circumstances a court could hold that the direct

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obligations of a subsidiary guaranteeing our debt securities could be superior to the obligations under that guarantee.

A court could avoid or subordinate the guarantee of our debt securities by any of our subsidiaries in favor of that subsidiary s other debts or liabilities to the extent that the court determined either of the following were true at the time the subsidiary issued the guarantee:

that subsidiary incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or that subsidiary contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or

that subsidiary did not receive fair consideration or reasonable equivalent value for issuing the guarantee and, at the time it issued the guarantee, that subsidiary:

was insolvent or rendered insolvent by reason of the issuance of the guarantee;

was engaged or about to engage in a business or transaction for which the remaining assets of that subsidiary constituted unreasonably small capital; or

intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

The measure of insolvency for purposes of the foregoing will vary depending upon the law of the relevant jurisdiction. Generally, however, an entity would be considered insolvent for purposes of the foregoing if the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all of its assets at a fair valuation, or if the present fair saleable value of its assets were less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and matured.

Among other things, a legal challenge of a subsidiary s guarantee of our debt securities on fraudulent conveyance grounds may focus on the benefits, if any, realized by that subsidiary as a result of our issuance of our debt securities. To the extent a subsidiary s guarantee of our debt securities is avoided as a result of fraudulent conveyance or held unenforceable for any other reason, the holders of our debt securities would cease to have any claim in respect of that guarantee.

The ability to transfer our debt securities may be limited by the absence of a trading market.

We do not currently intend to apply for listing of our debt securities on any securities exchange or stock market. The liquidity of any market for our debt securities will depend on the number of holders of those debt securities, the interest of securities dealers in making a market in those debt securities and other factors. Accordingly, we can give no assurance as to the development or liquidity of any market for the debt securities.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make required payments on our debt securities depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. Pursuant to the credit facilities, we may be required to establish cash reserves for the future payment of principal and interest on the amounts outstanding under our credit facilities. If we are unable to obtain the funds necessary to pay the principal amount at maturity of the debt securities, or to repurchase the debt securities upon the occurrence of a change of control, we may be required to adopt one or more alternatives, such as a refinancing of the debt securities. We cannot assure you that we would be able to refinance the debt securities.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service our debt securities or to repay them at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our available cash to our unitholders of record and our general partner. Available cash is generally all of our cash receipts adjusted for cash distributions and net changes to reserves. Our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating partnerships in amounts the general partner determines in its reasonable discretion to be necessary or appropriate:

to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);

to provide funds for distributions to our unitholders and the general partner for any one or more of the next four calendar quarters; or

to comply with applicable law or any of our loan or other agreements.

Although our payment obligations to our unitholders are subordinate to our payment obligations to debtholders, the value of our units will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue equity to recapitalize.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. and Canadian federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available to pay distributions and our debt obligations.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Because a tax would be imposed upon us as a corporation, the cash available for distributions or to pay our debt obligations would be substantially reduced.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we will be subject to a new entity level tax on the portion of our income that is generated in Texas beginning in our tax year ending in 2007. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such a tax upon us as an entity by Texas or any other state will reduce the cash available for distributions or to pay our debt obligations.

Proposed changes in Canadian tax law could subject our Canadian subsidiaries to entity-level tax, which would reduce the amount of cash available to pay distributions and our debt obligations.

In response to the perceived proliferation of income trusts in Canada, the Canadian government has issued proposed regulations that impose entity-level taxes on certain types of flow-through entities. At this point, final regulations have not been issued and it is not clear what impact the final regulations will have on our Canadian subsidiaries. Any entity-level taxation of our Canadian subsidiaries would reduce the cash available for distributions or to pay our debt obligations.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in our termination as a partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all of our unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution or debt service.

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

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

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive any cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

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

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

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

Investment in common units by tax-exempt entities, such as individual retirement accounts (IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income.

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

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

Our unitholders will likely be subject to foreign, state and local taxes and tax return filing requirements in jurisdictions where they do not live as a result of an investment in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign taxes, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property and in which they do not reside. We own property and conduct business in Canada and in most states in the United States. Unitholders will be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes in respect of our Canadian source income earned through partnership entities. A unitholder may also be required to file state and local income tax returns and pay state and local income taxes in many or all of the jurisdictions in which we conduct business or own property. Further, unitholders may be subject to penalties for failure to comply with those requirements. It is our unitholders responsibility to file all United States federal, state, local and foreign tax returns.

Item 1B. *Unresolved Staff Comments*

None.

Item 3. *Legal Proceedings*

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. 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 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 both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the U.S. Environmental Protection Agency (the EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $3.0 million to $3.5 million. In cooperation with the appropriate state and federal environmental authorities, we have substantially completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (the DOJ) for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act. We are cooperating in the investigation. Our assessment is that it is probable we will pay penalties related to the two releases. We have accrued the estimated loss contingency, which is included in the estimated aggregate costs set forth above. It is reasonably possible that the loss contingency may exceed our estimate with respect to penalties assessed by the DOJ; however, we have no indication from EPA or the DOJ of what penalties might be sought. As a result, we are unable to estimate the range of a reasonably possible loss contingency in excess of our accrual.

On November 15, 2006, we completed the Pacific acquisition. The following is a summary of the more significant matters that relate to Pacific, its assets or operations.

The People of the State of California v. Pacific Pipeline System, LLC (PPS). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger.

The release occurred when Line 63 was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. As of December 31, 2006, $26 million of remediation costs had been incurred. We estimate additional remediation costs of approximately $1 to $2 million, substantially all of which we expect to incur before June 2007. We anticipate that the majority of costs associated with this release will be covered under a pre-existing PPS pollution liability insurance policy.

In March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum state fine that can be assessed is estimated to be approximately $1,100,000, in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of recovered crude oil, and the State of California has the discretion to further reduce the fine after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the strict liability offenses cannot be ascertained. We will defend against these charges. In addition to these fines, the State of California has indicated that it may seek to recover approximately $150,000 in natural resource damages against PPS in connection with this matter. The mitigating factors may also serve as a basis for a downward adjustment of the natural resource damages amount. We believe that certain of the alleged violations are without merit and intend to defend against them, and that mitigating factors should apply.

In December 2006 we were informed that the EPA may be intending to refer this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. The DOJ has accepted the referral. We understand that the maximum permissible penalty that the EPA could assess under relevant statutes would be approximately $3.7 million. We believe that several mitigating circumstances and factors exist that could substantially reduce the penalty, and intend to pursue discussions with the EPA regarding such mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be assessed by the EPA cannot be ascertained. Discussions with the DOJ to resolve this matter have commenced.

Kosseff v. Pacific Energy, et al, case no. BC 3544016. On June 15, 2006, a lawsuit was filed in the Superior court of California, County of Los Angeles, in which the plaintiff alleged that he was a unitholder of Pacific and he sought to represent a class comprising all of Pacific s unitholders. The complaint named as defendants Pacific and certain of the officers and directors of Pacific s general partner, and asserted claims of self-dealing and breach of fiduciary duty in connection with the pending merger with us and related transactions. The plaintiff sought injunctive relief against completing the merger or, if the merger was completed, rescission of the merger, other equitable relief, and recovery of the plaintiff s costs and attorneys fees. On September 14, 2006, Pacific and the other defendants entered into a memorandum of settlement with the plaintiff to settle the lawsuit. As part of the settlement, Pacific and the other defendants deny all allegations of wrongdoing and express willingness to settle the lawsuit solely because the settlement would eliminate the burden and expense of further litigation. The settlement is subject to customary conditions, including court approval. As part of the settlement, we (as successor to Pacific) will pay $0.5 million to the plaintiff s counsel for their fees and expenses, and incur the cost of mailing materials to former Pacific unitholders. If finally approved by the court, the settlement will resolve all claims that were or could have been brought on behalf of the proposed settlement class in the actions being settled, including all claims relating to the merger, the merger agreement and any disclosure made by Pacific in connection with the merger. The settlement did not change any of the terms or conditions of the merger.

Air Quality Permits. In connection with the Pacific merger, we acquired Pacific Atlantic Terminals LLC (PAT), which is now one of our subsidiaries. PAT owns crude oil and refined products terminals in northern California. In the process of integrating PAT s assets into our operations, we identified certain aspects of the operations at the terminals that appeared to be out of compliance with specifications under the relevant air quality permit. We conducted a prompt review of the circumstances and self-reported the apparent historical occurrences of non-compliance to the Bay Area Air Quality Management District. We are cooperating with the District s review of these matters.

General. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these 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 November 9, 2006, the Partnership held a special meeting of its unitholders for the following purposes:

1. To consider and vote upon the approval and adoption of the Agreement and Plan of Merger dated as of June 11, 2006 by and among the Partnership, Plains AAP, L.P., Plains All American GP LLC, Pacific, Pacific Energy Management LLC and Pacific Energy GP, LP, as it may be amended from time to time (the Merger Agreement); and

2. To consider and vote upon the approval of the issuance of our common units to the common unitholders of Pacific (other than LB Pacific, LP), as provided in the Merger Agreement.

Holders of over 65% of our outstanding common units voted in favor of both proposals. The voting results were as follows:

Matter	For	Votes Cast Against	Abstain	Broker Non-Votes
Approve Merger Agreement	52,832,920	297,858	261,365	n/a
Approve Issuance of Units Pursuant to Merger Agreement	52,733,280	373,438	285,425	n/a

PART II

Item 5. ***Market For Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities***

Our common units are listed and traded on the New York Stock Exchange (NYSE) under the symbol PAA. On February 20, 2007, the closing market price for our common units was $54.67 per unit and there were approximately 70,000 record holders and beneficial owners (held in street name). As of February 20, 2007, there were 109,405,178 common units outstanding.

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

	Common Unit Price Range		Cash
	High	Low	Distributions(1)
2006			

1st Quarter	$ 47.00	$ 39.81	$ 0.7075
2nd Quarter	48.92	42.81	0.7250
3rd Quarter	47.35	43.21	0.7500
4th Quarter	53.23	45.20	0.8000
2005			
1st Quarter	$ 40.98	$ 36.50	$ 0.6375
2nd Quarter	45.08	38.00	0.6500
3rd Quarter	48.20	42.01	0.6750
4th Quarter	42.82	38.51	0.6875

(1) Cash distributions for a quarter are declared and paid in the following calendar quarter.

Our common units are used as a form of compensation to our employees. Additional information regarding our equity compensation plans is included in Part III of this report under Item 13. Certain Relationships and Related Transactions, and Director Independence.

Cash Distribution Policy

We will distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below. 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 and except for the agreed upon adjustment discussed below, 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.

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amounts due it as incentive distributions. The reduction will be effective for five years, as follows: (i) $5 million per quarter for the first four quarters, (ii) $3.75 million per quarter for the next eight quarters, (iii) $2.5 million per quarter for the next four quarters, and (iv) $1.25 million per quarter for the final four quarters. The total reduction in incentive distributions will be $65 million. The first quarterly reduction took place in connection with the distribution paid in February 2007.

We paid $33.1 million to the general partner in incentive distributions in 2006. On February 14, 2007, we paid a quarterly distribution of $0.80 per unit applicable to the fourth quarter of 2006. See Item 13. Certain Relationships and Related Transactions, and Director Independence 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.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of fiscal 2006.

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Item 6. ***Selected Financial Data***

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2006, 2005, 2004, 2003 and 2002 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,				
	2006	**2005**	**2004**	**2003**	**2002**
Statement of operations data:					
Total Revenues(1)	$ 22,444.4	$ 31,176.5	$ 20,975.0	$ 12,589.7	$ 8,383.8
Crude oil and LPG purchases and related costs(1)	(20,819.7)	(29,691.9)	(19,870.9)	(11,746.4)	(7,741.2)
Pipeline margin activities purchases(1)	(665.9)	(750.6)	(553.7)	(486.1)	(362.3)
Field operating costs	(369.8)	(272.5)	(219.5)	(139.9)	(106.4)
General and administrative expenses	(133.9)	(103.2)	(82.7)	(73.1)	(45.7)
Depreciation and amortization	(100.4)	(83.5)	(68.7)	(46.2)	(34.0)
Total costs and expenses	(22,089.7)	(30,901.7)	(20,795.5)	(12,491.7)	(8,289.6)
Operating income	354.7	274.8	179.5	98.0	94.2
Interest expense	(85.6)	(59.4)	(46.7)	(35.2)	(29.1)
Equity earnings in unconsolidated entities	7.7	1.8	0.5	0.2	0.4
Interest and other income (expense), net	2.3	0.6	(0.2)	(3.6)	(0.2)
Income tax expense	(0.3)				
Income before cumulative effect of change in accounting principle(2)	$ 278.8	$ 217.8	$ 133.1	$ 59.4	$ 65.3
Basic net income before cumulative effect of change in accounting principle(2)	$ 2.84	$ 2.77	$ 1.94	$ 1.01	$ 1.34
Diluted net income before cumulative effect of change in accounting principle(2)	$ 2.81	$ 2.72	$ 1.94	$ 1.00	$ 1.34
Basic weighted average number of limited partner units outstanding	81.1	69.3	63.3	52.7	45.5
Diluted weighted average number of limited partner units outstanding	81.9	70.5	63.3	53.4	45.5
Balance sheet data (at end of period):					

Total assets	$ 8,714.9	$ 4,120.3	$ 3,160.4	$ 2,095.6	$ 1,666.6
Total long-term debt(3)	2,626.3	951.7	949.0	519.0	509.7
Total debt	3,627.5	1,330.1	1,124.5	646.3	609.0
Partners capital	2,976.8	1,330.7	1,070.2	746.7	511.6
Other data:					
Maintenance capital expenditures	$ 28.2	$ 14.0	$ 11.3	$ 7.6	$ 6.0
Net cash provided by (used in) operating activities(4)	(275.3)	24.1	104.0	115.3	185.0
Net cash (used in) investing activities(4)	(1,651.0)	(297.2)	(651.2)	(272.1)	(374.9)
Net cash provided by financing activities	1,927.0	270.6	554.5	157.2	189.5
Declared distributions per limited partner unit(5)(6)	2.87	2.58	2.30	2.19	2.11
Volumes (thousands of barrels per day)(7)					
Transportation segment:					
Tariff activities	2,018	1,725	1,412	824	564
Pipeline margin activities	88	74	74	78	73
Total	2,106	1,799	1,486	902	637

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	Year Ended December 31,				
	2006	2005	2004	2003	2002
Facilities Segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	20.7	16.8	14.8	12.0	3.8
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	12.9	4.3			
LPG processing (thousands of barrels per day)	12.2				
Total (average monthly capacity in millions of barrels)(8)	23.2	17.5	14.8	12.1	3.9
Marketing segment:					
Crude oil lease gathering	650	610	589	437	410
LPG sales	70	56	48	38	35
Waterborne foreign crude imported	63	59	12	N/A	N/A
Total	783	725	649	475	445

(1) Includes buy/sell transactions for all periods prior to the second quarter of 2006. See Note 2 to our Consolidated Financial Statements.

(2) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2006 change in our method of accounting for unit-based payment transactions would have been $224.1 million, $136.3 million, $65.7 million, and $71.6 million for 2005, 2004, 2003 and 2002, respectively. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $2.81 ($2.76 diluted), $1.98 ($1.98 diluted), $1.13 ($1.12 diluted) and $1.47 ($1.47 diluted) for 2005, 2004, 2003 and 2002, respectively. Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2004 change in our method of accounting for pipeline linefill in third-party assets would have been $61.4 million and $64.8 million for 2003 and 2002, 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) and $1.33 ($1.33 diluted) for 2003 and 2002, respectively.

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

(4) In conjunction with the change in accounting principle we adopted as of January 1, 2004, we have reclassified cash flows for 2003 and prior years 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.

(5) Distributions represent those declared and paid in the applicable year.

(6) 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 5 to our Consolidated Financial Statements.

(7) 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 year.

(8) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly volumes in millions.

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 and Internal Growth Projects
- 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

Executive Summary

Company Overview

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products (liquefied petroleum gas and other natural gas related petroleum products are collectively referred to as LPG). In addition, through our 50% equity ownership in PAA/Vulcan, we develop and operate natural gas storage facilities. We were formed in September 1998, and our operations are conducted directly and indirectly through our operating subsidiaries.

Prior to the fourth quarter of 2006, we managed our operations through two segments. Due to our growth, especially in the facilities portion of our business (most notably in conjunction with the Pacific acquisition), we have revised the manner in which we internally evaluate our segment performance and decide how to allocate resources to our segments. As a result, we now manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines and gathering systems. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity, transportation fees, barrel exchanges and buy/sell arrangements. Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Our marketing segment operations generally consist of merchant activities associated primarily with the purchase and sale of crude oil and LPG. Our marketing activities are designed to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside exposure to opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to reduce the negative impact of market volatility and provide counter-cyclical balance.

Overview of Operating Results, Capital Spending and Significant Activities

During 2006, we recognized net income of $285.1 million and earnings per diluted limited partner unit of $2.88, compared to net income of $217.8 million and earnings per diluted limited partner unit of $2.72 during 2005.

Both 2006 and 2005 were substantial increases over 2004. Net income was $130.0 million and earnings per diluted limited partner unit was $1.89 for 2004. Key items impacting 2006 include:

Balance Sheet and Capital Structure

The completion of the Pacific acquisition for approximately $2.5 billion (including the equity issuance and assumption of debt discussed below), and six other acquisitions for aggregate consideration of approximately $565 million.

The issuance of 22 million limited partner units (valued at $1.0 billion) in exchange for Pacific limited partner units as part of the Pacific acquisition and the sale of 13.4 million limited partner units for net proceeds of approximately $621 million.

The assumption of $433 million of senior notes as part of the Pacific acquisition and the issuance of $1,250 million of Senior Notes for net proceeds of approximately $1,243 million.

Capital expenditures (excluding acquisitions and maintenance capital) of $332 million.

Limited partner distributions of $224.9 million ($2.87 per limited partner unit) and General Partner distributions of $37.7 million paid during 2006.

Income Statement

Favorable execution of our risk management strategies in our marketing segment in a pronounced contango market with a high level of overall crude oil volatility.

Increased volumes and related tariff revenues on our pipeline systems.

An increase in field operating costs and general and administrative expenses primarily associated with continued growth from acquisitions as well as internal growth projects and an increase of $17 million in 2006 related to our Long-Term Incentive Plans. See Critical Accounting Policies and Estimates Critical Accounting Estimates Long-Term Incentive Plan Accruals.

A charge of approximately $4 million in 2006 resulting from the mark-to-market of open derivative instruments pursuant to SFAS 133.

A gain of approximately $6 million resulting from the reduction of our obligation for outstanding LTIP awards, which was recorded as a cumulative effect of change in accounting principle pursuant to the adoption of SFAS No. 123(R) (revised 2004), Share-Based Payment.

Prospects for the Future

Access to storage tankage by our marketing segment provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow associated with this segment. 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 a base level of margin irrespective of crude oil market conditions and, in certain circumstances, to realize incremental margin during volatile market conditions.

During 2006, we strengthened our business by expanding our asset base through approximately $3 billion of acquisitions and $332 million of internal growth projects. In 2007, we intend to spend approximately $500 million on internal growth projects and also to continue to develop our inventory of projects for implementation beyond 2007. Several of the larger storage tank projects for 2007, such as the construction or expansion of the Patoka, Cushing and St. James terminals, are well positioned to benefit from the importation of waterborne foreign crude oil into the Gulf Coast as well as the importation of Canadian crude oil. We also believe there are opportunities for us to grow our LPG business. In addition, our 2005 entry into the natural gas storage business and our 2006 entries into the refined products transportation and storage business and the barge transportation business are consistent with our stated strategy of leveraging our assets, business model, knowledge and expertise into businesses that are complementary to our existing activities. We will continue to look for ways to grow these businesses and continue to evaluate opportunities in other complementary midstream business activities. Specifically, we intend to apply our business model to the refined products business by establishing and growing a marketing and distribution business to complement our strategically located assets. 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 midstream infrastructure.

Although we believe that we are well situated in the North American midstream infrastructure, we face various operational, regulatory and financial challenges that may impact our ability to execute our strategy as planned. In addition, we operate in a mature industry and believe that acquisitions will play an important role in our potential growth. We will continue to pursue the purchase of midstream assets, and we will also continue to initiate expansion projects designed to optimize product flows in the areas in which we operate. However, we can give no assurance that our current or future acquisition or expansion efforts will be successful. See Item 1A. Risk Factors Risks Related to Our Business.

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2006, 2005 and 2004 that have impacted our results of operations and enabled us to enhance our liquidity, as discussed herein. The following table summarizes our capital expenditures for acquisitions (including equity investments), capital expansion (internal growth projects) and maintenance capital for the periods indicated (in millions):

	December 31,		
	2006	2005	2004
Acquisition capital(1)	$ 3,021.1	$ 40.3	$ 563.9
Investment in PAA/Vulcan Gas Storage, LLC	10.0	112.5	
Investment in Settoon Towing	33.6		
Internal growth projects	332.0	148.8	117.3
Maintenance capital	28.2	14.0	11.3
	$ 3,424.9	$ 315.6	$ 692.5

(1) Acquisition capital includes deposits in the year the acquisition closed, rather than the year the deposit was paid. Deposits paid were approximately $12 million for the Shell Gulf Coast Pipeline Systems acquisition in 2004.

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Internal Growth Projects

As a result of capital expansion opportunities originating from prior acquisitions, we increased our annual level of spending on these projects by 123% in 2006 compared to 2005. The following table summarizes our 2006 and 2005 projects (in millions):

Projects	2006	2005
St. James, Louisiana storage facility Phase I	$ 69.9	$ 15.2
St. James, Louisiana storage facility Phase II	12.9	
Trenton pipeline expansion	12.3	31.8
Kerrobert tankage	28.5	4.3
East Texas/Louisiana tankage	12.0	
Spraberry System expansion	15.4	
Cushing Phase IV and V expansions	1.1	11.2
Cushing Tankage Phase VI	10.1	
Cushing to Broome pipeline		8.2
Northwest Alberta fractionator	2.2	15.6
Link acquisition asset upgrades		9.3
High Prairie rail terminals	9.1	
Midale/Regina truck terminal	12.7	
Truck trailers	9.9	
Wichita Falls tankage	7.8	
Basin connection Oklahoma	6.9	
Mobile/Ten Mile tankage and metering	4.0	
Cheyenne Pipeline Construction	10.3	
Other Projects	106.9	53.2
Total	$ 332.0	$ 148.8

Our 2006 projects included the construction and expansion of pipeline systems and crude oil storage and terminal facilities (notably Cushing and St. James). We expect internal growth capital projects to expand further in 2007. See Liquidity and Capital Resources Capital Expenditures and Distributions Paid to Unitholders and General Partners 2007 Capital Expansion Projects.

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our credit facilities and the issuance of senior notes. The businesses acquired impacted our results of operations commencing on the effective date of each acquisition as indicated in the table below. Our ongoing acquisitions and capital expansion activities are discussed further in Liquidity and Capital Resources. See Note 3 to our Consolidated Financial Statements for additional information about our acquisition activities.

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2006 Acquisitions

In 2006, we completed several acquisitions for aggregate consideration of approximately $3.0 billion. The Pacific merger was material to our operations. See Note 3 to our Consolidated Financial Statements. The following table summarizes the acquisitions that were completed in 2006, and a description of our material acquisitions follows the table (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Pacific	11/15/2006	$ 2,455.7	Transportation, Facilities, Marketing
Andrews	4/18/2006	220.1	Transportation Facilities, Marketing
SemCrude	5/1/2006	129.4	Marketing
BOA/CAM/HIPS	7/31/2006	130.2	Transportation
Products Pipeline	9/1/2006	65.6	Transportation
Other	various	20.1	Transportation, Facilities, Marketing
Total		$ 3,021.1	

Pacific. On November 15, 2006 we completed our acquisition of Pacific pursuant to an Agreement and Plan of Merger dated June 11, 2006. The merger-related transactions included: (i) the acquisition from LB Pacific of the general partner interest and incentive distribution rights of Pacific as well as approximately 5.2 million Pacific common units and approximately 5.2 million Pacific subordinated units for a total of $700 million and (ii) the acquisition of the balance of Pacific s equity through a unit-for-unit exchange in which each Pacific unitholder (other than LB Pacific) received 0.77 newly issued common units of the Partnership for each Pacific common unit. The total value of the transaction was approximately $2.5 billion, including the assumption of debt and estimated transaction costs. Upon completion of the merger-related transactions, the general partner and limited partner ownership interests in Pacific were extinguished and Pacific was merged with and into the Partnership. The assets acquired in the Pacific acquisition included approximately 4,500 miles of active crude oil pipeline and gathering systems and 550 miles of refined products pipelines, over 13 million barrels of active crude oil storage capacity and 9 million barrels of refined products storage capacity, a fleet of approximately 75 owned or leased trucks and approximately 1.9 million barrels of crude oil and refined products linefill and working inventory. The Pacific assets complement our existing asset base in California, the Rocky Mountains and Canada, with minimal asset overlap but attractive potential vertical integration opportunities. The results of operations and assets and liabilities from the Pacific acquisition have been included in our consolidated financial statements since November 15, 2006. The purchase price allocation related to the Pacific acquisition is preliminary and subject to change. See Note 3 to our Consolidated Financial Statements.

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

Cash payment to LB Pacific	$ 700.0
Value of Plains common units issued in exchange for Pacific common units	1,001.6
Assumption of Pacific debt (at fair value)	723.8

Estimated transaction costs(1)		30.3
Total purchase price	$	2,455.7

(1) Includes investment banking fees, costs associated with a severance plan in conjunction with the acquisition and various other direct acquisition costs.

Purchase Price Allocation	
Property, plant and equipment, net	$ 1,411.7
Investment in Frontier	8.7
Inventory	32.6
Pipeline linefill and inventory in third party assets	63.6
Intangible assets	72.3
Goodwill(1)	843.2
Assumption of working capital and other long-term assets and liabilities, including $20.0 of cash	23.6
Total purchase price	$ 2,455.7

(1) Represents the preliminary amount in excess of the fair value of the net assets acquired and is associated with our view of the future results of operations of the businesses acquired based on the strategic location of the assets and the growth opportunities that we expect to realize as we integrate these assets into our existing business strategy.

The majority of the acquisition costs associated with the Pacific acquisition was incurred as of December 31, 2006, resulting in total cash paid during 2006 of approximately $723 million.

The following table shows our calculation of the sources of funding for the acquisition (in millions):

Fair value of Plains common units issued in exchange for Pacific common units	$ 1,001.6
Plains general partner capital contribution	21.6
Assumption of Pacific debt (at estimated fair value), net of repayment of Pacific credit facility(1)	433.1
Plains new debt incurred	999.4
Total sources of funding	$ 2,455.7

(1) The assumption of Pacific s debt and credit facility at fair value was $433.1 million and $290.7 million, respectively. We paid off the credit facility in connection with closing of the transaction.

Other 2006 Acquisitions. During 2006, we completed six additional acquisitions for aggregate consideration of approximately $565 million. These acquisitions included (i) 100% of the equity interests of Andrews Petroleum and Lone Star Trucking, which provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids (collectively, the Andrews acquisition), (ii) crude oil gathering and transportation assets and related contracts in South Louisiana (SemCrude), (iii) interests in various crude oil pipeline systems in Canada and the U.S. including a 100% interest in the BOA Pipeline, various interests in HIPS and a 64.35% interest in the CAM Pipeline system, and (iv) three refined products pipeline systems.

In addition, in November 2006, we purchased a 50% interest in Settoon Towing for approximately $33 million. Settoon Towing owns and operates a fleet of 57 transport and storage barges as well as 30 transport tugs. Its core business is the gathering and transportation of crude oil and produced water from inland production facilities across the Gulf Coast.

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2005 Acquisitions

We completed six small transactions in 2005 for aggregate consideration of approximately $40.3 million. The transactions included crude oil trucking operations and several crude oil pipeline systems along the Gulf Coast as well as in Canada. We also acquired an LPG pipeline and terminal in Oklahoma. These acquisitions did not materially impact our results of operations, either individually or in the aggregate. The following table summarizes our acquisitions that were completed in 2005 (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Shell Gulf Coast Pipeline Systems(1)	1/1/2005	$ 12.0	Transportation
Tulsa LPG Pipeline	3/2/2005	10.0	Marketing
Other acquisitions	Various	18.3	Transportation, Facilities, Marketing
Total		$ 40.3	

(1) A $12 million deposit for the Shell Gulf Coast Pipeline Systems acquisition was paid into escrow in December 2004.

In addition, in September 2005, PAA/Vulcan acquired Energy Center Investments LLC (ECI), an indirect subsidiary of Sempra Energy, for approximately $250 million. ECI develops and operates underground natural gas storage facilities. We own 50% of PAA/Vulcan and the remaining 50% is owned by a subsidiary of Vulcan Capital. We made a $112.5 million capital contribution to PAA/Vulcan and we account for the investment in PAA/Vulcan under the equity method in accordance with Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock.

2004 Acquisitions

In 2004, we completed several acquisitions for aggregate consideration of approximately $563.9 million. The Link and Capline acquisitions were material to our operations. See Note 3 to our Consolidated Financial Statements. The following table summarizes our acquisitions that were completed in 2004, and a description of our material acquisitions follows the table (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Capline and Capwood Pipeline Systems (Capline acquisition)(1)	03/01/04	$ 158.5	Transportation
Link Energy LLC (Link acquisition)	04/01/04	332.3	Transportation, Facilities, Marketing
Cal Ven Pipeline System	05/01/04	19.0	Transportation
Schaefferstown Propane Storage Facility(2)	08/25/04	46.4	Facilities

Other	various	7.7	Facilities, Marketing
Total	$	563.9	

(1) Includes a deposit of approximately $16 million which was paid in December 2003 for the Capline acquisition.

(2) Includes approximately $14.4 million of LPG operating inventory acquired.

Capline and Capwood Pipeline Systems. The principal assets acquired 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 58-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. 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.

Link Energy LLC. The Link crude oil business we acquired consisted 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.

Critical Accounting Policies and Estimates

Critical Accounting Policies

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with generally accepted accounting principles in the United States. These critical accounting policies are discussed in Note 2 to the Consolidated Financial Statements.

Critical Accounting Estimates

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

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. Accordingly, a variance from this estimate of 10% would impact the respective line items by less than 1% on an annual basis. In addition, we estimate that less than 4% of total operating income and less than 5% of total net income are recorded using estimates. 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 mark-to-market derivatives 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 annual 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 and governmental penalties, insurance claims, asset retirement obligations, taxes, 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 environmental 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 $5.2 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. The purchase price allocation related to the Pacific acquisition is preliminary and subject to change. See Note 3 to our Consolidated Financial Statements.

Long-Term Incentive Plan Accruals. We also make accruals to recognize the fair value of our outstanding LTIP awards as compensation expense. Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding LTIP awards and recognize that fair value as compensation expense over the course of the LTIP award s vesting period. For LTIP awards that contain a performance condition, the fair value of the LTIP award is recognized as compensation expense only if the attainment of the performance condition is considered probable. The amount of the actual charge to compensation expense will be determined by the unit price on the date vesting occurs (or, in some cases, the average unit price for a range of dates preceding the vesting date) multiplied by the number of units, plus our share of associated employment taxes. Uncertainties involved in this estimate include the actual unit price at time of settlement, whether or not a performance condition will be attained and the continued employment of personnel subject to the vestings.

We achieved a $3.20 annualized distribution rate and therefore we are accruing compensation expense for LTIP awards that vest upon the attainment of that rate. We recognized total compensation expense of approximately $42.7 million in 2006 and $26.1 million in 2005 related to awards granted under our various LTIP plans. We cannot provide assurance that the actual fair value of our LTIP awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.

Goodwill. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable. We consider the estimate of fair value to be a critical accounting estimate because (a) a goodwill impairment could have a material impact on our financial position and results of operations and (b) the estimate is based on a number of highly subjective judgments and assumptions.

Property, Plant and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. We periodically evaluate property, plant and equipment for impairment

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when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property, plant and equipment a critical accounting estimate. In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of holding versus selling an asset;
- the forecast of undiscounted expected future cash flow over the asset s estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

Asset Retirement Obligation

We account for asset retirement obligations under SFAS No. 143 Accounting for Asset Retirement Obligations. SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including estimates related to (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense and (4) subsequent measurement of the liability. 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.

Some of our assets, primarily related to our transportation segment, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. These obligations include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets and returning the land to its original state. The timing of the obligations is determined relative to the date on which the asset is abandoned.

Many of our pipelines are trunk and interstate systems that transport crude oil. The pipelines with indeterminate settlement dates have been in existence for many years and with regular maintenance will continue to be in service for many years to come. Also, it is not possible to predict when demands for this transportation will cease and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligations. We will record asset retirement obligations for these assets in the period in which sufficient information becomes available for us to reasonably determine the settlement dates. A small portion of our contractual or regulatory obligations are related to assets that are inactive or that we plan to take out of service and although the ultimate timing and costs to settle these obligations are not known with certainty, we can reasonably estimate the obligation.

Recent Accounting Pronouncements and Change in Accounting Principle

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will impact us, see Note 2 to our Consolidated Financial Statements.

Changes in Accounting Principle

Stock-Based Compensation

In December 2004, SFAS 123(R) was issued, which amends SFAS No. 123, Accounting for Stock-Based Compensation, and establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement requires that the cost resulting from such share-based payment transactions be recognized in the financial statements at fair value. Following our general partner s adoption of Emerging Issues Task Force Issue No. 04-05, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights, we are now part of the same consolidated group and thus SFAS 123(R) is applicable to our general partner s long-term incentive plan. We adopted SFAS 123(R) on January 1, 2006 under the modified prospective transition method, as defined in SFAS 123(R), and recognized a cumulative effect of change in accounting principle of approximately $6 million. The cumulative effect adjustment represents a decrease to our LTIP life-to-date accrued expense and related liability under our previous cash-plan, probability-based accounting model and adjusts our aggregate liability to the appropriate fair-value based liability as calculated under a SFAS 123(R) methodology. Our LTIPs are administered by our general partner. We are required to reimburse all costs incurred by our general partner through LTIP settlements. As a result, our LTIP awards are classified as liabilities under SFAS 123(R). Under the modified prospective transition method, we are not required to adjust our prior period financial statements for our LTIP awards.

Linefill

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we 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 did not include linefill barrels in the same average costing calculation as our operating inventory, but instead carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we 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 on the consolidated balance sheet.

This change in accounting principle was effective January 1, 2004 and is reflected as a cumulative change in our consolidated statement of operations for the year ended 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.

Results of Operations

Analysis of Operating Segments

Prior to the fourth quarter of 2006, we managed our operations through two segments. Due to our growth, especially in the facilities portion of our business most notably in conjunction with the Pacific acquisition, we have revised the manner in which we internally evaluate our segment performance and decide how to allocate resources to our segments. As a result, we now manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. Prior period disclosures have been revised to reflect our change in segments.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases and related costs, (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 mitigate the actual decline in the value of our principal fixed assets. 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, which is deducted in determining available cash, 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 considered expansion capital expenditures,

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not 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. See Note 15 to our Consolidated Financial Statements for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the marketing segment secures transportation and facilities services from the Partnership s other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Inter-segment transportation service rates are based on posted tariffs for pipeline transportation services. Facilities segment services are also obtained at rates consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our marketing segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties. We believe that the estimates with respect to the rates that are charged by our facilities segment to our marketing segment are reasonable. We also allocate certain operating expense and general and administrative overheads between segments. We believe that the estimates with respect to the allocations are reasonable.

Transportation

As of December 31, 2006, we owned approximately 20,000 miles of active gathering and mainline crude oil and refined products pipelines located throughout the United States and Canada as well as approximately 60 million barrels of active above-ground crude oil, refined products and LPG storage tanks, of which approximately 30 million barrels are utilized in our transportation segment. Our activities from transportation operations generally consist of transporting crude oil and refined products 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 addition, we transport crude oil for third parties for a fee using our trucks and barges. These barge transportation services are provided through our 50% owned entity, Settoon Towing. Our transportation segment also includes our equity in earnings from our investment in Settoon Towing, Butte and Frontier. Butte and Frontier are pipeline systems in which we own approximately 22% and 22%, respectively. In connection with certain of our merchant activities conducted under our marketing business, we are also shippers on a number of 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 transportation segment for the periods indicated:

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Operating Results(1)			
Revenues			
Tariff revenue	$ 449.5	$ 381.1	$ 309.9
Pipeline margin activities	23.6	20.0	18.1
Third-party trucking	60.9	34.1	20.9
Total pipeline operations revenues	534.0	435.2	348.9
Costs and Expenses			
Pipeline margin activities purchases	(3.2)	(2.0)	(1.5)
Third-party trucking	(68.1)	(48.2)	(26.4)
Field operating costs (excluding LTIP charge)	(200.7)	(164.5)	(131.0)
LTIP charge operations(3)	(4.5)	(1.0)	(0.6)
Segment G&A expenses (excluding LTIP charge)(2)	(42.9)	(40.2)	(36.6)
LTIP charge general and administrative(3)	(16.3)	(10.6)	(3.4)
Equity in earnings from unconsolidated entities	1.9	0.8	0.5
Segment profit	$ 200.2	$ 169.5	$ 149.9
Maintenance capital	$ 20.0	$ 8.5	$ 7.7
Segment profit per barrel	$ 0.26	$ 0.26	$ 0.28
Average Daily Volumes (thousands of barrels per day)(4)			
Tariff activities			
All American	49	51	54
Basin	332	290	265
BOA/CAM	89	N/A	N/A
Capline	160	132	123
Cushing to Broome	73	66	N/A
North Dakota/Trenton	89	77	39
West Texas/New Mexico Area Systems(5)	433	428	338
Canada	272	255	263
Other	521	426	330
Total tariff activities	2,018	1,725	1,412
Pipeline margin activities	88	74	74
Transportation Activities Total	2,106	1,799	1,486

(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 management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(3) Compensation expense related to our 1998 Long-Term Incentive Plan (1998 LTIP), our 2005 Long-Term Incentive Plan (2005 LTIP), and our 2006 Long-Term Incentive Tracking Unit Plan (2006 Plan and, together with the 1998 Plan and 2005 Plan, the Long-Term Incentive Plans or LTIP).

(4) 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.

(5) The aggregate of multiple systems in the West Texas/New Mexico area.

Segment profit, our primary measure of segment performance, was impacted by the following:

Increased volumes and related tariff revenues The increase in tariff revenues resulted from (i) higher volumes primarily from multi-year contracts on our Basin and Capline systems entered into during the third quarter of 2006 and the second quarter of 2006, respectively, (ii) increased volumes associated with the acquisition of the BOA/CAM/HIPS systems, (iii) higher volumes on various other systems, and (iv) increased revenues from loss allowance oil. As is common in the industry, our crude oil tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. The loss allowance factor averages approximately 0.2%, by volume. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Gains or losses on subsequent sales of allowance oil barrels are also included in tariff revenues. Increased volumes and higher crude oil prices during 2006 as compared to 2005 have resulted in increased revenues related to loss allowance oil. The average NYMEX crude oil price for 2006 was $66.27 per barrel versus $56.65 in 2005 and $41.29 in 2004. The increase in volumes and related tariff revenues in 2005 versus 2004 is primarily related to the Link acquisition and other acquisitions completed during 2005 and 2004. The increase primarily resulted from the inclusion of the related assets for the entire 2005 period versus only a portion of the 2004 period.

Increased field operating costs Field operating costs have increased for most categories of costs for 2006 as we have continued to grow through acquisitions and expansion projects. The most significant cost increases in 2006 have been related to (i) payroll and benefits, (ii) utilities, (iii) integrity work, and (iv) property taxes. Utilities increased approximately $10 million in 2006 over the prior year due to a variety of factors including (i) an increase in electricity consumption related to increased volumes, partially offset by lower electricity market prices and (ii) a true-up of prior and current accruals following receipt of final billing information upon expiration of an existing term arrangement with a significant electricity provider. Our costs increased in 2005 as compared to 2004, primarily from the Link acquisition and other acquisitions completed during 2004. The 2005 increased costs primarily relate to (i) payroll and benefits, (ii) emergency response and environmental remediation of pipeline releases, (iii) maintenance and (iv) utilities.

Increased segment G&A expenses Segment G&A expenses excluding LTIP charges were relatively flat in 2006 compared to 2005. The increase in segment G&A expenses in 2005 is primarily related to the acquisition activity.

Increased LTIP expenses LTIP charges included in field operating costs and segment G&A expenses increased approximately $9 million in 2006 over 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. LTIP-related charges increased approximately $8 million in 2005 over 2004, primarily as a result of LTIP grants made in 2005 and an increase in our unit price. Our unit price at December 31, 2004 was $37.74 per unit. See Note 10 to our Consolidated Financial Statements.

As discussed above, the increase in transportation segment profit is largely related to our acquisition activities. We have completed a number of acquisitions during 2006, 2005 and 2004 that have impacted our results of operations. The following table summarizes the year-over-year impact that recent acquisitions and expansion projects have had on tariff revenue and volumes:

	Change in the Periods for the Year Ended December 31,			
	2006 vs 2005		2005 vs 2004	
	Revenues	Volumes	Revenues	Volumes
	(Volumes in thousands of barrels per day and revenues in millions)			
Tariff activities(1)(2)(3)				
2006 acquisitions/expansions	$ 32.8	178	$ N/A	N/A
2005 acquisitions/expansions	5.7	8	14.1	96
2004 acquisitions/expansions	2.7	28	22.6	140
2003 acquisitions/expansions	6.2	10	13.0	17
All other pipeline systems	21.0	69	21.5	60
Total tariff activities	$ 68.4	293	$ 71.2	313

(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 year.

(3) To the extent there has been an expansion to one of our existing pipeline systems, any incremental revenues and volumes from the expansion are included in the category for the period that the pipeline was acquired. For new pipeline systems that we construct, incremental revenues and volumes are included in the period the system became operational.

In 2006, average daily volumes from our tariff activities increased by approximately 300 thousand barrels per day or 17% and tariff revenues increased by approximately $68 million or 18%. The increase in volumes and tariff revenues is attributable to a combination of the following factors:

Pipeline systems acquired or brought into service during 2006, which contributed approximately 178,000 barrels per day and $33 million of revenues during 2006;

Revenues from some of the Canadian pipeline systems increased approximately $9 million in 2006 primarily due to the appreciation of Canadian currency (the Canadian to US dollar exchange rate appreciated to an average of 1.13 to 1 for 2006 compared to an average of 1.21 to 1 in 2005);

An increase of approximately $7 million from our loss allowance oil primarily resulting from higher crude oil prices;

Volumes and revenues from pipeline systems in which we entered into new multi-year contracts with shippers, which contributed approximately 70,000 barrels per day and approximately $4 million of revenues during 2006; and

Increased volumes and revenues from the North Dakota/Trenton pipeline system resulting from our expansion activities on that system.

In 2005, average daily volumes from our tariff activities increased by approximately 300 thousand barrels per day or 22% and revenues from our tariff activities increased by approximately $71 million or 23%. The increase in total revenues is attributable to a combination of the following factors:

Pipeline systems acquired or brought into service during 2005, which contributed approximately 96,000 barrels per day and $14.1 million of revenues during 2005. Approximately 66,000 barrels per day and $7.2 million of revenues are attributable to our recently constructed Cushing to Broome pipeline system.

Volumes and revenues from pipeline systems acquired in 2004 increased in 2005 as compared to 2004, reflecting the following:

An increase of 118,000 barrels per day and $15.8 million of revenues from the pipelines acquired in the Link acquisition, reflecting the inclusion of these systems for the entire 2005 period as compared to only a portion of the 2004 period. The 2005 period also includes (i) increased revenues from our loss allowance oil resulting from higher crude oil prices and (ii) increased revenues from the North Dakota/Trenton pipeline system resulting from our expansion activities on that system. These increases were partially offset by the impact of a reduction in tariff rates that were voluntarily lowered to encourage third party shippers. Transportation segment profit was reduced by approximately $12.0 million because of these market rate adjustments. As a result of these lower tariffs on barrels shipped by us in connection with our gathering and marketing activities, segment profit from marketing was increased by a comparable amount,

An increase of 17,000 barrels per day and $4.4 million of revenues from the pipelines acquired in the Capline acquisition, reflecting the inclusion of these systems for the entire 2005 period as compared to only a portion of the 2004 period, and

An increase of 5,000 barrels per day and $2.4 million of revenues from other businesses acquired in 2004.

Volumes and revenues from pipeline systems acquired in 2003 increased in 2005 as compared to 2004, reflecting the following:

An increase of 5,000 barrels per day and $5.2 million of revenues from the Red River pipeline system acquisition, reflecting increased tariff rates on the system, partially related to the quality of crude oil shipped,

An increase of $3.0 million of revenues related to higher realized prices on our loss allowance oil, and

An increase of 12,000 barrels per day and $4.8 million of revenues in 2005 compared to 2004 from other businesses acquired in 2003, primarily related to higher volumes.

Revenues from all other pipeline systems also increased in 2005, along with a slight increase in volumes. The increase in revenues is related to several items including:

The appreciation of Canadian currency (the Canadian to U.S. dollar exchange rate appreciated to an average of 1.21 to 1 for 2005 compared to an average of 1.30 to 1 in 2004), and

Volume increases on certain of our systems, partially related to a shift of certain minor pipeline systems from our marketing segment.

Maintenance Capital

For the years ended December 31, 2006, 2005 and 2004, maintenance capital expenditures for our transportation segment were approximately $20.0 million, $8.5 million and $7.7 million, respectively. The increase in 2006 is due to our continued growth through acquisitions and expansion projects.

Facilities

As of December 31, 2006, we owned approximately 60 million barrels of active above-ground crude oil, refined products and LPG storage tanks, of which approximately 30 million barrels are included in our facilities segment. The remaining tanks are utilized in our transportation segment. At year end 2006, the Partnership was in the process of constructing approximately 12.5 million barrels of additional above ground terminalling and storage facilities, which we expect to place in service during 2007 and 2008.

Our facilities segment generally consists of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. On a stand-alone basis, segment profit from facilities activities is dependent on the storage capacity leased, volume of throughput and the level of fees for such services.

We generate fees through a combination of month-to-month and multi-year leases and processing arrangements. Fees generated in this segment include (i) storage fees that are generated when we lease tank capacity and (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil or refined products from one connecting pipeline and redeliver crude oil or refined products to another connecting carrier.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2006, PAA/Vulcan owned and operated approximately 25.7 billion cubic feet of underground storage capacity and was constructing an additional 24 billion cubic feet of underground storage capacity.

Total revenues for our facilities segment have increased over the three-year period ended December 31, 2006. The revenue increase in each period is driven primarily by increased volumes resulting from our acquisition activities and, to a lesser extent, tankage construction projects completed in 2005 and 2006.

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

	December 31,		
	2006	**2005**	**2004**
	(In millions, except per barrel amounts)		
Operating Results			
Storage and Terminalling Revenues(1)	$ 87.7	$ 41.9	$ 33.9
Field operating costs	(39.6)	(17.8)	(11.0)
LTIP charge operations(3)	(0.1)		
Segment G&A expenses (excluding LTIP charge)(2)	(13.5)	(7.7)	(3.6)
LTIP charge general and administrative(3)	(5.7)	(2.2)	(1.1)
Equity earnings in unconsolidated entities	5.8	1.0	
Segment profit	$ 34.6	$ 15.2	$ 18.2
Maintenance capital	$ 4.9	$ 1.1	$ 2.0
Segment profit per barrel	$ 1.49	$ 0.87	$ 1.23
Volumes (millions of barrels)(4)			
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	20.7	16.8	14.8
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	12.9	4.3	
LPG processing (thousands of barrels per day)	12.2		
Facilities activities total (average monthly capacity in millions of barrels)(5)	23.2	17.5	14.8

(1) Revenues 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 management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(3) Compensation expense related to our Long-Term Incentive Plans.

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

(5) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing

volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly volumes in millions.

Segment profit (our primary measure of segment performance) and revenues were impacted in 2006 by the following:

Increased revenues from crude facilities   The increase in volumes and related revenues during 2006 primarily relates to (i) increased volumes stored due to a pronounced contango market, (ii) the Pacific acquisition and other acquisitions completed during 2006 and 2005, and (iii) the utilization of capacity at the Mobile facility that was acquired from Link in 2004 but not used extensively until 2006;

Increased revenues from LPG facilities   The increase in volumes and related revenues during 2006 primarily relates to four LPG facilities that were brought into service during 2005 but were operational for the entire 2006 period compared to only a portion of 2005;

Increased revenues from refined product storage and terminalling   The Pacific acquisition introduced a refined products storage and terminalling revenue stream in 2006, which contributed additional revenues of $5.3 million; and

Increased revenues from LPG processing   The acquisition of the Shafter processing facility during 2006 resulted in additional processing revenues of approximately $24 million.

Segment profit was also impacted in 2006 by the following:

Increased field operating costs   Our continued growth, primarily from the acquisitions completed during 2006 and 2005 and the additional tankage added in 2006 and 2005, is the principal cause of the increase in field operating costs in 2006. Of the total increase, $10.9 million relates to the operating costs associated with the Shafter processing facility. The remainder of the increase in operating costs primarily relate to (i) payroll and benefits, (ii) maintenance and (iii) utilities;

Increased segment G&A expenses   Segment G&A expenses excluding LTIP charges increased in 2006 compared to 2005 primarily as a result of an increase in the indirect costs allocated to the facilities segment in 2006 as the operations have grown in that period;

Increased LTIP expenses   LTIP charges included in field operating costs and segment G&A expenses increased approximately $3.6 million in 2006 over 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. LTIP related charges increased approximately $1.1 million in 2005 over 2004 primarily as a result of LTIP grants made in 2005 and an increase in our unit price. Our unit price at December 31, 2004 was $37.74 per unit (see Note 10 to our Consolidated Financial Statements); and

Increased equity in earnings from unconsolidated entities   Our investment in PAA/Vulcan contributed $4.8 million in additional earnings, reflecting the inclusion of this investment for the entire 2006 period compared to only two months in 2005.

Segment profit and revenues also increased in 2005 compared to 2004 and were impacted by the following:

Increased revenues from crude facilities   The increase in volumes and related revenues during 2005 primarily relates to (i) increased volumes stored due to a pronounced contango market, (ii) acquisitions completed during 2005 and 2004, and (iii) increased throughput at our Cushing terminal; and

Increased revenues from LPG facilities The increase in volumes and related revenues during 2005 primarily relates to acquisitions of new facilities completed during 2005; at the end of 2005, we owned ten facilities compared to four at the beginning of 2004.

Segment profit in 2005 was also impacted by the following:

Increased field operating costs Our continued growth, primarily from the acquisitions completed during 2005 and 2004 and the additional tankage added in 2005 and 2004, is the principal cause of the increase in field operating costs in 2005. The increased costs primarily relate to (i) payroll and benefits, (ii) maintenance and (iii) utilities; and

Increased segment G&A expenses Segment G&A expenses excluding LTIP charges increased in 2005 compared to 2004 primarily as a result of an increase in the indirect costs allocated to the facilities segment in 2005 as the operations grew in that period. LTIP related charges increased approximately $1.1 million in 2005 over 2004 primarily as a result of LTIP grants made in 2005 and an increase in our unit price. Our unit price at December 31, 2004 was $37.74 per unit.

Maintenance Capital

For the years ended December 31, 2006, 2005 and 2004, maintenance capital expenditures for our facilities segment were approximately $4.9 million, $1.1 million and $2.0 million, respectively. The increase in 2006 is primarily due to additional maintenance requirements at our Alto and Shafter facilities.

Marketing

Our revenues from marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, as well as marketing of natural gas liquids, 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. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in our marketing segment volumes (which consist of (i) lease gathered volumes, (ii) LPG sales, and (iii) waterborne foreign crude imported) as well as the overall volatility and strength or weakness of market condition and the allocation of our assets among our various hedge positions. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business and our hedging activities provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period.

Revenues from our marketing operations were approximately $22.1 billion, $30.9 billion and $20.8 billion for the years ended December 31, 2006, 2005 and 2004, respectively. Total revenues for our marketing segment decreased in 2006 as compared to 2005 due to a combination of the following factors:

A decrease in our 2006 revenues due to the adoption of EITF 04-13 which was equally offset with purchases and related costs and does not impact segment profit (see Note 2 to our Consolidated Financial Statements); offset by

An increase in the average NYMEX price for crude oil in 2006 as compared to 2005. The average NYMEX price for crude oil was $66.27, $56.65 and $41.29 per barrel for the years ended December 31, 2006, 2005 and 2004, respectively. 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.

In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit, (ii) marketing segment volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our marketing segment for the comparable periods indicated:

	December 31,		
	2006	**2005**	**2004**
	(In millions, except per barrel amounts)		
Operating Results(1)			
Revenues(2)(3)	$ 22,060.8	$ 30,893.0	$ 20,750.7
Purchases and related costs(4)(5)	(21,640.6)	(30,578.4)	(20,551.2)
Field operating costs (excluding LTIP charge)	(136.6)	(94.4)	(80.9)
LTIP charge operations(6)	(0.1)	(2.3)	
Segment G&A expenses (excluding LTIP charge)(7)	(39.5)	(32.5)	(35.2)
LTIP charge general and administrative(6)	(16.0)	(10.0)	(2.8)
Segment profit(3)	$ 228.0	$ 175.4	$ 80.6
SFAS 133 mark-to-market adjustment(3)	$ (4.4)	$ (18.9)	$ 1.0
Maintenance capital	$ 3.3	$ 4.4	$ 1.6
Segment profit per barrel(8)	$ 0.80	$ 0.66	$ 0.34
Average Daily Volumes (thousands of barrels per day)(9)			
Crude oil lease gathering	650	610	589
LPG sales	70	56	48
Waterborne foreign crude imported	63	59	12
Marketing Activities Total	783	725	649

(1) Revenues and purchases and related costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $4,761.9 million, $16,274.9 million and $11,396.8 million for the years ended December 31, 2006, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 919,500, 851,900 and 800,700 barrels per day for the years ended December 31, 2006, 2005 and 2004, respectively. The previously referenced amounts include certain estimates based on management s judgment; such estimates are not expected to have a material impact on the balances. See Note 2 to our Consolidated Financial Statements.

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

(4) Includes purchases associated with buy/sell arrangements of $4,795.1 million, $16,106.5 million and $11,280.2 million for the years ended December 31, 2006, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 926,800, 851,900 and 800,700 barrels per day for the years ended

December 31, 2006, 2005 and 2004, respectively. The previously referenced amounts include certain estimates based on management s judgment; such estimates are not expected to have a material impact on the balances. See Note 2 to our Consolidated Financial Statements.

(5) Purchases and related costs include interest expense on contango inventory purchases of $49.2 million, $23.7 million and $2.0 million for the years ended December 31, 2006, 2005 and 2004, respectively.

(6) Compensation expense related to our Long-Term Incentive Plans.

(7) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

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(8) Calculated based on crude oil lease gathered volumes, LPG sales volumes, and waterborne foreign crude volumes.

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

Segment profit for 2006 ($228.0 million) exceeded the segment profit for 2005 ($175.4 million). The increase was primarily related to very favorable market conditions and successful execution of risk management strategies coupled with increased volumes and synergies realized from businesses acquired in the last two years.

The primary factors affecting current period results were:

Acquisitions During 2006 we purchased certain crude oil gathering assets and related contracts in South Louisiana and Andrews Petroleum and Lone Star Trucking. The Andrews acquisition impacted our facilities, marketing and transportation segments. See Note 3 to our Consolidated Financial Statements.

Favorable market conditions and execution of our risk management strategies During 2006 and 2005, the crude oil market experienced significantly high volatility in prices and market structure. The NYMEX benchmark price of crude oil ranged from $54.86 to $78.40 during 2006. The volatile market allowed us to utilize risk management strategies to optimize and enhance the margins of our gathering and marketing activities. The market was in contango for most of 2006 and the time spread of prices averaged approximately $1.22 versus $0.72 for 2005; this increase in spreads was partially offset by an increase in the cost to carry the inventory that was not only impacted by the increase in LIBOR rates but also by the increase in NYMEX prices. Marketing segment profit includes contango and other hedged inventory related interest expense of approximately $49.2 million for 2006 incurred to store the crude oil. This cost is included in Purchases and related costs in the table above.

SFAS 133 mark-to-market 2006 includes SFAS 133 mark-to-market losses of $4.4 million compared to a loss of $18.9 million for 2005. See Note 6 to our Consolidated Financial Statements.

Inventory Adjustment In 2006, we recognized a $5.9 million non-cash charge primarily associated with declines in oil prices and other product prices during the third and fourth quarters of 2006 and the related decline in the valuation of working inventory volumes. Approximately $3.4 million of the charge relates to crude oil inventory in pipelines owned by third parties and the remainder relates to LPG and other products inventory.

Field operating costs and segment G&A expenses Field operating costs (excluding LTIP charges) increased in 2006 compared to 2005, primarily as a result of increases in (i) payroll and benefits and contract transportation as a result of 2006 acquisitions, (ii) fuel costs and (iii) maintenance costs. The increase in general and administrative expenses (excluding LTIP charges) is primarily the result of an increase in the indirect costs allocated to the marketing segment in 2006 as the operations have grown. The increase in field operating costs in 2005 compared to 2004 was primarily the result of an increase in (i) fuel costs and (ii) payroll and benefits.

Increased LTIP expenses LTIP charges included in field operating costs and segment G&A expenses increased approximately $3.8 million in 2006 over 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. LTIP related charges increased approximately $9.5 million in 2005 over 2004 primarily as a result of LTIP grants made in 2005 and an increase in our unit price. Our unit price at December 31, 2004 was $37.74 per unit. See Note 10 to our Consolidated Financial

Statements.

Segment profit per barrel (calculated based on our marketing volumes included in the table above) was $0.80 for 2006, compared to $0.66 for 2005 and $0.34 for 2004. As discussed above, our current period results were impacted by favorable market conditions. We are not able to predict with any reasonable level of accuracy whether market conditions will remain as favorable as have recently been experienced, and these operating results may not be indicative of sustainable performance.

Maintenance capital

For the years ended December 31, 2006, 2005 and 2004, maintenance capital expenditures were approximately $3.3 million, $4.4 million, and $1.6 million, respectively, for our marketing segment.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $100.4 million for the year ended December 31, 2006, compared to $83.5 million and $68.7 million for the years ended December 31, 2005 and 2004, respectively. The increases in 2006 and 2005 related primarily to an increased amount of depreciable assets resulting from our acquisition activities and capital projects. Also contributing to the increase in 2005 was a non-cash loss related to sales of assets. Amortization of debt issue costs was $2.5 million in 2006, $2.8 million in 2005, and $2.5 million in 2004.

Interest Expense

Interest expense was $85.6 million for the year ended December 31, 2006, compared to $59.4 million and $46.7 million for the years ended December 31, 2005 and 2004, respectively. Interest expense is primarily impacted by:

- our average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith;
- market interest rates and our interest rate hedging activities on floating rate debt; and
- interest capitalized on capital projects.

The following table summarizes selected components of our average debt balances:

	For the Year Ended December 31,					
	2006		2005		2004	
	Total	% of Total	Total	% of Total	Total	% of Total
	(Dollars in millions)					
Fixed rate senior notes(1)	$ 1,336	92%	$ 891	87%	$ 586	68%
Borrowings under our revolving credit facilities(2)	118	8%	135	13%	274	32%
Total	$ 1,454		$ 1,026		$ 860	

(1) Weighted average face amount of senior notes, exclusive of discounts.

(2) Excludes borrowings under our senior secured hedged inventory facility and capital leases.

The issuance of senior notes and the assumption of Pacific s debt in 2006 resulted in an increase in the average amount of longer term and higher cost fixed-rate debt outstanding in 2006. The overall higher average debt balances in 2006 and 2005 were primarily related to the portion of our acquisitions that were not financed with equity, coupled with borrowings related to other capital projects. During 2006, 2005 and 2004, the average LIBOR rate was 5.0%, 3.2%, and 1.6%, respectively. Our weighted average interest rate, excluding commitment and other fees, was approximately 6.1% in 2006, compared to 5.6% and 5.0% in 2005 and 2004, respectively. The impact of the increased debt balance was an increase in interest expense of $26.0 million, and the impact of the higher weighted-average interest rate was an increase in interest expense of $4.7 million. Both of these increases were primarily offset by an increase in capitalized interest of $4.2 million. The net impact of the items discussed above was an increase in interest expense in 2006 of approximately $26.2 million.

The higher average debt balance in 2005 as compared to 2004 resulted in additional interest expense of approximately $12.7 million, while at the same time our commitment and other fees decreased by approximately $1.8 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.6% for 2005 compared to 5.0% for 2004. The higher weighted average rate increased interest expense by approximately $12.7 million in 2005 compared to 2004.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our marketing segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately $49.2 million, $23.7 million and $2.0 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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 regarding potential acquisitions by us of transportation, gathering, terminalling or storage assets and related midstream businesses. These acquisition efforts often involve assets that, if acquired, could 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 midstream businesses outside of the scope of our current operations, but with respect to which these resources effectively can be applied. For example, during 2006 we entered the refined products transportation and storage business as well as the barge transportation business. We are presently engaged in discussions and negotiations with various parties regarding the acquisition of assets and businesses described above, but 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.

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 regulations in Canada) 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 additional assets.

In September 2006, the DOT published a Notice of Proposed Rulemaking (NPRM) that proposed to regulate certain hazardous liquid gathering and low stress pipeline systems that are not currently subject to regulation. On December 6, 2006, the Congress passed, and on December 29, 2006 President Bush signed into law, H.R. 5782, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Pipeline Safety Act), which reauthorizes and amends the DOT s pipeline safety programs. Included in the 2006 Pipeline Safety Act is a provision eliminating the regulatory exemption for hazardous liquid pipelines operated at low stress, which was one of the focal points of the September 2006 NPRM. The Act requires DOT to issue regulations by December 31, 2007 for those hazardous liquid low stress pipelines now subject to regulation pursuant to the Act. Regulations issued by December 31, 2007 with respect to hazardous liquid low stress pipelines as well as any future regulation of hazardous liquid gathering lines could include requirements for the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact these developments will have on our operating expenses and, thus, cannot provide any assurances that future costs related to these programs will not be material.

In addition to performing DOT-mandated pipeline integrity evaluations, during 2006, we expanded an internal review process started in 2005 in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rule. The purpose of this process is to review the surrounding environment, condition and operating history of these pipelines and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we may be required (as a result of additional DOT regulation) or we may elect (as a result of our own initiatives) 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.

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

- Continued overall depletion of U.S. crude oil production.
- The continuing convergence of worldwide crude oil supply and demand trends.
- The expected extension of DOT regulations to low stress and gathering pipelines.
- Industry compliance with the DOT s adoption of API 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.
- The addition of inspection requirements by EPA for storage tanks not subject to DOT s API 653 requirements.
- 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 tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings, which were evident in 2005. 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.

We are also regularly evaluating midstream businesses that are complementary to our existing businesses and that possess attractive long-term growth prospects. Through PAA/Vulcan s acquisition of ECI in 2005, the Partnership entered the natural gas storage business. Although our investment in natural gas storage assets is currently relatively small when considering the Partnership s overall size, we intend to grow this portion of our business through future acquisitions and expansion projects. We believe that strategically located natural gas storage facilities will become increasingly important in supporting the reliability of gas service needs in the United States. Rising demand for natural gas is outpacing domestic natural gas production, creating an increased need for imported natural gas. A continuation of this trend will result in increased natural gas imports from Canada and the Gulf of Mexico, and LNG imports. We believe our business strategy and expertise in hydrocarbon storage will allow us to grow our natural gas storage platform and benefit from these trends.

During 2006, we entered the refined products transportation and storage business. We believe that this business will be driven by increased demand for refined products, growth in the capacity of refineries and increased reliance on imports. We believe that demand for refined products will increase as a result of multiple specifications of existing products (also referred to as boutique gasoline blends), specification changes to existing products, such as ultra low sulfur diesel, and new products, such as bio-fuels. In addition, capacity creep as well as large expansion projects at existing refineries will likely necessitate construction of additional refined products transportation and storage infrastructure. We intend to grow our asset base in the refined products business through future acquisitions and expansion projects. We also intend to apply our business model to the refined products business by establishing and growing a marketing and distribution business to complement our strategically located assets.

Liquidity and Capital Resources

The Partnership has a defined financial growth strategy that states how we intend to finance our growth and sets forth targeted credit metrics. We have also established a targeted credit rating. See Items 1 and 2. Business and Properties Financial Strategy.

Cash flow from operations and our credit facilities are our primary sources of liquidity. At December 31, 2006, we had working capital of approximately $133 million, approximately $1.25 billion of availability under our committed revolving credit facilities and approximately $0.4 million of availability under our uncommitted hedged inventory facility. Usage of the credit facilities is subject to ongoing compliance with covenants. We believe we are currently in compliance with all covenants.

Cash flow from operations

The crude oil market was in contango for much of 2006 and 2005. Because we own crude oil storage capacity, during a contango market we can buy crude oil in the current month and simultaneously hedge the crude by selling it forward for delivery in a subsequent month. This activity can cause significant fluctuations in our cash flow from operating activities as described below.

The primary drivers of cash flow from our operations are (i) the collection of amounts related to the sale of crude oil and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services, and (ii) the payment of amounts related to the purchase of crude oil and other products 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 (i) in the months that we store the purchased crude oil and hedge it by selling it forward for delivery in a subsequent month because of contango market conditions or (ii) in months in which we increase our share of linefill in third party pipelines. The storage of crude oil in periods of a contango market can have a material negative impact on our cash flows from operating activities for the period in which we pay for and store the crude oil (as is the case for much of 2006, including at December 31, 2006) and a material positive impact in the subsequent period in which we receive proceeds from the sale of the crude oil. In the month we pay for the stored crude oil, we borrow under our credit facilities (or pay from cash on hand) to pay for the crude oil, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, but to a lesser extent, the level of LPG and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it. Our accounts payable and accounts receivable generally vary proportionately because we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. However, when the market is in contango, our accounts receivable, accounts payable, inventory and short-term debt balances are all impacted, depending on the point of the cycle at any particular period end. As a result, we can have significant fluctuations in those working capital accounts, as we buy, store and sell crude oil.

Our cash flow used in operating activities in 2006 was $275.3 million compared to cash provided by operating activities of $24.1 million in 2005. This change reflects cash generated by our recurring operations offset by an increase in certain working capital items of approximately $703 million. In 2006, the market was in contango and we increased our storage of crude oil and other products (financed through borrowings under our credit facilities), resulting in a negative impact on our cash flows from operating activities for the period, as explained above. The fluctuations in accounts receivable and other and accounts payable and other current liabilities are primarily related to purchases and sales of crude oil that generally vary proportionately.

Cash flow from operating activities was $24.1 million in 2005 and reflects cash generated by our recurring operations (as indicated above in describing the primary drivers of cash generated from operations), offset by changes in components of working capital, including an increase in inventory. A significant portion of the increased inventory has been purchased and stored due to contango market conditions and was paid for during the period via borrowings under our credit facilities or from cash on hand. As mentioned above, this activity has a negative impact in the period that we pay for and store the inventory. In addition, there was a change in working capital resulting from higher NYMEX margin deposits paid during 2005 that had a negative impact on our cash flows from operations. The fluctuations in accounts receivable and other and accounts payable and other current liabilities are primarily related to purchases and sales of crude oil that generally vary proportionately.

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Cash flow from operating activities 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 factor 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 flow from operations was also negatively impacted by a decrease of approximately $20 million in prepayments received from counterparties to mitigate credit risk.

Cash provided by equity and debt financing activities

We periodically access the capital markets for both equity and debt financing. We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $2 billion of debt or equity securities. At December 31, 2006, we have approximately $1.1 billion of unissued securities remaining available under this registration statement.

Cash provided by financing activities was $1,927.0 million, $270.6 million and $554.5 million for each of the last three years, respectively. Our financing activities primarily relate to funding (i) acquisitions, (ii) internal capital projects and (iii) short-term working capital and hedged inventory borrowings related to our contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings under our credit facilities. During 2006, we borrowed under our credit facilities to pay for the storage of crude oil and other products under contango market conditions.

Equity Offerings. During the last three years we completed several equity offerings as summarized in the table below. Certain of these offerings involved related parties. See Note 9 to our Consolidated Financial Statements:

2006			2005			2004		
Units		Net Proceeds(1)(2)	Units		Net Proceeds(1)	Units		Net Proceeds(1)
6,163,960	$	305.6	5,854,000	$	241.9	4,968,000	$	160.9
3,720,930		163.2	575,000		22.3	3,245,700		101.2
3,504,672		152.4		$	264.2		$	262.1
	$	621.2						

(1) Includes our general partner s proportionate capital contribution and is net of costs associated with the offering.

(2) Excludes the common units issued and our general partner s proportionate capital contribution of $21.6 million pertaining to the equity exchange for the Pacific acquisition.

Senior Notes and Credit Facilities. During the three years ended December 31, 2006 we completed the sale of senior unsecured notes as summarized in the table below.

Year	Description	Face Value	Net Proceeds(1)

2006	6.125% Senior Notes issued at 99.56% of face value	$	400	$	398.2
	6.65% Senior Notes issued at 99.17% of face value	$	600	$	595.0
	6.7% Senior Notes issued at 99.82% of face value	$	250	$	249.6
2005	5.25% Senior Notes issued at 99.5% of face value	$	150	$	149.3
2004	4.75% Senior Notes issued at 99.6% of face value	$	175	$	174.2
	5.88% Senior Notes issued at 99.3% of face value	$	175	$	173.9

(1) Face value of notes less the applicable discount (before deducting for initial purchaser discounts, commissions and offering expenses).

During the year ended December 31, 2006, we had net working capital and hedged inventory borrowings of approximately $618.8 million. These borrowings are used primarily for purchases of crude oil inventory that was stored. See Cash flow from operations. During 2006 and 2005, we also had net repayments on our long-term revolving credit facility of approximately $298.5 million and $143.7 million, respectively, resulting from cash generated from our operations and other financing activities. During 2004, we had net borrowings on our long-term revolving credit facility of approximately $64.9 million. During 2005, we had net working capital and hedged inventory borrowings of approximately $206.1 million and during 2004 we had net borrowings of approximately $42.8 million. For further discussion related to our credit facilities and long-term debt, see Credit Facilities and Long-term Debt.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

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 and the financing activities discussed above. Our primary uses of cash are for our acquisition activities, capital expenditures for internal growth projects and distributions paid to our unitholders and general partner. See Acquisitions and Internal Growth Projects. The price of the acquisitions includes cash paid, transaction costs and assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year.

Distributions to unitholders and general partner. We 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 in the discretion of our general partner for future requirements. Total cash distributions made during the last three years were as follows (in millions, except per unit amounts):

	Distributions Paid					
Year	Common Units	Subordinated Units(1)	GP Incentive	GP 2%	Total	Distribution per Unit
2006	$ 224.9	$	$ 33.1	$ 4.6	$ 262.6	$ 2.87
2005	$ 178.4	$	$ 15.0	$ 3.6	$ 197.0	$ 2.58
2004	$ 142.9	$ 4.2	$ 8.3	$ 3.0	$ 158.4	$ 2.30

(1) The subordinated units were converted to common units in 2004.

2007 Capital Expansion Projects. Our 2007 projects include the following projects with the estimated cost for the entire year (in millions):

Projects	**2007**
St. James, Louisiana Storage Facility	$ 75.0
Salt Lake City Expansion	55.0
Patoka Tankage	40.0
Cheyenne Pipeline	34.0
Martinez Terminal	27.0
Cushing Tankage Phase VI	27.0
Paulsboro Expansion	20.0
West Hynes Tanks	15.0
Kerrobert Tankage	14.0
Fort Laramie Tank Expansion	12.0
High Prairie Rail Terminal	11.0
Pier 400	10.0
Other Projects	160.0
Subtotal	500.0
Maintenance Capital	45.0
Total	$ 545.0

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.

Credit Facilities and Long-term Debt

In July 2006, we amended our senior unsecured revolving credit facility to increase the aggregate capacity from $1.0 billion to $1.6 billion and the sub-facility for Canadian borrowings from $400 million to $600 million. The amended facility can be expanded to $2.0 billion, subject to additional lender commitments, and has a final maturity of July 2011.

In November 2006, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $800 million to $1.0 billion. We also extended the maturity of the senior secured hedged inventory facility to November 2007.

We also have several issues of senior debt outstanding that total $2.6 billion, excluding premium or discount, and range in size from $150 million to $600 million and mature at various dates through 2037. See Note 9 to our Consolidated Financial Statements.

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In November 2006, in conjunction with the Pacific merger, we assumed two issues of Senior Notes with an aggregate principal balance of $425 million. Interest payments on the $175 million of 6.25% Senior Notes are due on March 15 and September 15 of each year. The notes mature on September 15, 2015. Interest payments on the $250 million of 7.125% Senior Notes are due on June 15 and December 15 of each year. The notes mature on June 15, 2014. We have the option to redeem the notes, in whole or in part, at any time on or after the date noted at the following redemption prices:

$175 Million 6.25% Notes		$250 Million 7.125% Notes	
Year	**Percentage**	**Year**	**Percentage**
September 2010	103.125%	June 2009	103.563%
September 2011	102.083	June 2010	102.375
September 2012	101.042	June 2011	101.188
September 2013 and thereafter	100.000	June 2012 and thereafter	100.000

In October 2006, we issued $400 million of 6.125% Senior Notes due 2017 and $600 million of 6.65% Senior Notes due 2037. The notes were sold at 99.56% and 99.17% of face value, respectively. Interest payments are due on January 15 and July 15 of each year. We used the proceeds to fund the cash portion of our merger with Pacific. Net proceeds in excess of the cash portion of the merger consideration were used to repay amounts outstanding under our credit facilities and for general partnership purposes. In anticipation of the issuance of these notes, we had entered into $200 million notional principal amount of U.S. treasury locks to hedge the treasury rate portion of the interest rate on a portion of the notes. The treasury locks were entered into at an interest rate of 4.97%.

During May 2006, we completed the sale of $250 million aggregate principal amount of 6.70% Senior Notes due 2036. The notes were sold at 99.82% of face value. Interest payments are due on May 15 and November 15 of each year. We used the proceeds to repay amounts outstanding under our credit facilities and for general partnership purposes.

All our notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for two subsidiaries with assets regulated by the California Public Utility Commission, and certain minor subsidiaries. See Note 12 to our Consolidated Financial Statements.

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; and
- 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 a debt coverage ratio that will not be greater than 4.75 to 1.0 on all outstanding debt and 5.25 to 1.0 on 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.

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Contingencies

See Note 11 to our Consolidated Financial Statements.

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 creditworthy 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, 2006.

	Total	2007	2008	2009 (In millions)	2010	2011	2012 and Thereafter
Long-term debt and interest payments(1)	$ 5,181.6	$ 167.5	$ 167.5	$ 339.4	$ 159.2	$ 158.5	$ 4,189.5
Leases(2)	394.3	37.0	33.9	28.9	22.2	18.6	253.7
Capital expenditure obligations	11.5	11.5					
Other long-term liabilities(3)	101.2	49.3	12.1	17.6	12.9	1.8	7.5
Subtotal	5,688.6	265.3	213.5	385.9	194.3	178.9	4,450.7
Crude oil and LPG purchases(4)	4,612.2	2,667.6	738.3	449.0	322.5	240.3	194.5
Total	$ 10,300.8	$ 2,932.9	$ 951.8	$ 834.9	$ 516.8	$ 419.2	$ 4,645.2

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at December 31, 2006 (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 $21.4 million non-current liability related to SFAS 133 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 periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2006, we had outstanding letters of credit of approximately $185.8 million.

Capital Contributions to PAA/Vulcan Gas Storage, LLC. We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund equity requests associated with certain projects specified in the joint venture agreement. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for up to 50% of such equity requests. In some cases, Vulcan Gas Storage s obligation is subject to a maximum amount, beyond which Vulcan Gas Storage s participation is optional. For any other capital expenditures, or capital expenditures with respect to which Vulcan Gas Storage s participation is optional, if Vulcan Gas Storage elects not to participate, we have the right to make additional capital contributions to fund 100% of the project until our interest in PAA/Vulcan equals 70%. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage s interest. Once PAA s ownership interest is 70% or more, Vulcan Gas Storage would have the right, but not the obligation, to make future capital contributions proportionate to its ownership interest at the time. See Note 8 to our Consolidated Financial Statements.

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 in the discretion of our general partner for future requirements. On February 14, 2007, we paid a cash distribution of $0.80 per unit on all outstanding units. The total distribution paid was approximately $104.6 million, with approximately $87.5 million paid to our common unitholders and approximately $17.1 million paid to our general partner for its general partner interest ($1.8 million) and incentive distribution interest ($15.3 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.

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amounts of its incentive distributions commencing with the earlier to occur of (i) the payment date of the first quarterly distribution declared and paid after the closing date that equals or exceeds $0.80 per unit or (ii) the payment date of the second quarterly distribution declared and paid after the closing date. Such adjustment shall be as follows: (i) $5 million per quarter for the first four quarters, (ii) $3.75 million per quarter for the next eight quarters, (iii) $2.5 million per quarter for the next four quarters, and (iv) $1.25 million per quarter for the final four quarters. Pursuant to this agreement, the incentive distribution paid to the general partner on February 14, 2007 was reduced by $5 million. The total reduction in incentive distributions will be $65 million.

In 2006, we paid $33.1 million in incentive distributions to our general partner. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner.

Off-Balance Sheet Arrangements

We have invested in certain entities (PAA/Vulcan, Butte, Settoon Towing and Frontier) that are not consolidated in our financial statements. In conjunction with these investments, from time to time we may elect to provide financial and performance guarantees or other forms of credit support. See Note 9 to our Consolidated Financial Statements for more information concerning our obligations as they relate to our investment in PAA/Vulcan.

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

We are exposed to various market risks, including volatility in (i) crude oil, refined products, natural gas and LPG commodity prices, (ii) interest rates and (iii) currency exchange rates. We utilize various derivative instruments to manage such exposure and, in certain circumstances, to realize incremental margin during volatile market conditions. 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. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX, ICE 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. Our risk management function also approves all new risk management strategies through a formal process. With the exception of the controlled trading program discussed below, our approved strategies are intended to mitigate enterprise level risks that are inherent in our core businesses of gathering and marketing and storage. 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, refined products, natural gas and LPG in storage, and expected purchases and sales of these commodities (relating primarily to crude oil and LPGs at this time). The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX, ICE and over-the-counter transactions, including swap and option contracts entered into with financial institutions and other energy companies. Our policy is to purchase only commodity products for which we have a market, and to structure our sales contracts so that price fluctuations for those products do not materially affect the segment profit we receive. Except for the controlled trading program discussed below, we do not acquire and hold futures contracts or other derivative products for the purpose of speculating on price changes, as these activities could expose us to significant losses.

Although we seek to maintain a position that is substantially balanced within our various commodity purchase and sales activities (which mainly relate to crude oil and LPGs), 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.

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 to our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2006 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 increase are shown in the table below:

	Fair Value	Effect of 10% Price Increase
	(In millions)	
Crude oil:		
Futures contracts	$ (13.5)	$ (54.9)
Swaps and options contracts	$ (27.8)	$ (23.6)
LPG and other:		
Futures contracts	$ (4.8)	$ 5.9
Swaps and options contracts	$ 13.6	$ 0.7
Total Fair Value	$ (32.5)	

The fair value of futures contracts is based on quoted market prices obtained from the NYMEX or ICE. The fair value of swaps and option contracts is 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 used in these estimates as well as the source for the estimates are 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 increase 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 use 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 use interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. In addition, in connection with the Pacific merger, we assumed interest rate swaps with an aggregate notional amount of $80 million. The interest rate swaps are a hedge against changes in the fair value of the 7.125% Senior Notes resulting from market fluctuations to LIBOR. 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, 2006. All of our senior notes are fixed rate notes and thus 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, 2006. 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						
	2007	2008	2009	2010	2011	Thereafter	Total
	(Dollars in millions)						
Liabilities:							
Short-term debt variable rate	$ 993.5	$	$	$	$	$	$ 993.5
Average interest rate	5.8%						5.8%

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 may include forward exchange contracts and cross currency swaps.

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					
	2007	2008	2009	2010	2011	Total
Forward exchange contracts	$ (2.0)	$	$	$	$	$ (2.0)
Total	$ (2.0)	$	$	$	$	$ (2.0)

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

See Index to the Consolidated Financial Statements on page F-1.

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

Not applicable.

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, 2006, 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, 2006. See Management s Report on Internal Control Over Financial Reporting on page F-2.

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

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2006 that has not previously been reported.

PART III

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

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 (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 GP LLC. References to our officers, directors and employees are references to the officers, directors and employees of GP LLC (or, in the case of our Canadian 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 our 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. Our general partner has the sole discretion to incur indebtedness or other obligations on our behalf on a non-recourse basis to the general partner.

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. The corporate governance of 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. Specifically, our partnership agreement defines Board of Directors to mean the board of directors of GP LLC, which consists of up to eight directors elected by the members of GP LLC, and not by our unitholders. The Board currently consists of seven directors. Under the Second Amended and Restated Limited Liability Company Agreement of GP LLC (the GP LLC Agreement), three of the members of GP LLC have the right to designate one director each and our CEO is a director by virtue of holding the office. In addition, the GP LLC Agreement provides that three independent directors (and an eighth seat that is currently vacant) are elected, and may be removed, by a majority of the membership interest. The vacant seat is not required to be independent.

In August 2005, a former member s 19% interest in the general partner was sold pro rata to the other general partner owners, resulting in Vulcan Energy s ownership interest increasing from 44% to 54%. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest.

In connection with this transaction, Vulcan Energy entered into an agreement with GP LLC pursuant to which Vulcan Energy has agreed to restrict certain of its voting rights to help preserve a balanced board. Vulcan Energy has agreed that, with respect to any action taken involving the election or removal of an independent director, Vulcan Energy will vote all of its interest in excess of 49.9% in the same way and proportionate to the votes of all membership interests other than Vulcan Energy s. Without the voting agreement, Vulcan Energy s ownership interest would allow Vulcan Energy, in effect, to unilaterally elect five of the eight board seats: the Vulcan Energy designee, the currently vacant seat and the three independent directors (subject, in the case of the independent directors, to the qualification requirements of the GP LLC Agreement, our partnership agreement, NYSE listing standards and SEC regulations). Vulcan Energy has the right at any time to give notice of termination of the agreement. The time between notice and termination depends on the circumstances, but would never be longer than one year. In connection with the August 2005 transaction, Messrs. Armstrong and Pefanis entered into waivers of the change in control provisions of their employment agreements, which otherwise would have been triggered by the transaction. These waivers were contingent upon Vulcan s execution of the voting agreement, and will terminate upon any breach or termination by Vulcan Energy of, or notice of termination under, the voting agreement. See Item 11. Executive Compensation Employment Contracts and Potential Payments upon Termination or Change-in-Control.

Another member, Lynx Holdings I, LLC, also agreed to certain restrictions on its voting rights with respect to its approximate 1.2% interest in GP LLC and Plains AAP, L.P. The Lynx voting agreement requires Lynx to vote its membership interest (in the context of elections or the removal of an independent director) in the same way and proportionate to the votes of the other membership interests (excluding Vulcan s and Lynx s). Lynx has the right to terminate its voting agreement at any time upon termination of the Vulcan voting agreement or the sale or transfer of all of its interest in the general partner to an unaffiliated third party.

Non-Management Executive Sessions and Shareholder Communications

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 the General Counsel and Secretary or 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.

Independence Determinations and Audit Committee

Because we are a limited partnership, the listing standards of the NYSE 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

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directors. We are, however, required to have an audit committee, and all of its members are required to be independent as defined by the NYSE.

Under NYSE listing standards, to be considered independent, our board of directors must determine that a director has no material relationship with us other than as a director. The standards specify the criteria by which the independence of directors will be determined, including guidelines for directors and their immediate family members with respect to employment or affiliation with us or with our independent public accountants.

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 charter of our audit committee is available on our website. See Meetings and Other Information. The board of directors has determined that each member of our audit committee (Messrs. Goyanes, Smith and Symonds) is (i) independent under applicable NYSE rules and (ii) an Audit Committee Financial Expert, as that term is defined in Item 407 of Regulation S-K.

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 President and Chief Executive Officer of Liberty Energy Holdings, LLC (LEH), a subsidiary of Liberty Mutual Insurance Company. LEH makes investments in producing properties, from some of which Plains Marketing, L.P. buys the production. LEH does not operate the properties in which it invests. Plains Marketing pays the same amount per barrel to LEH that it pays to other interest owners in the properties. In 2006, the amount paid to LEH by Plains Marketing was approximately $1.1 million (net of severance taxes). The board has determined that the transactions with LEH are not material and do not compromise Mr. Goyanes independence.

Mr. J. Taft Symonds, a member of our audit committee, was a director and the non-executive Chairman of the Board of Tetra Technologies, Inc. (Tetra) through December 2006. A subsidiary of Tetra owns crude oil producing properties, from some of which Plains Marketing buys the production. Mr. Symonds was not an officer of Tetra, and did not participate in operational decision making, including decisions concerning selection of crude oil purchasers or entering into sales or marketing arrangements. In 2006, the amount paid to the Tetra subsidiary by Plains Marketing was approximately $14.0 million (net of severance taxes). The board has determined that the transactions with Tetra were not material and did not compromise Mr. Symonds independence.

Mr. Arthur L. Smith, a member of our audit committee, has no relationships with either GP LLC or us, other than as a director and unitholder.

Compensation Committee

We have a compensation committee that reviews and makes recommendations to the board regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. The charter of our compensation committee is available on our website. See Meetings and Other Information. The compensation committee currently consists of Messrs. Capobianco, Petersen and Sinnott. Under applicable stock exchange rules, none of the members of our compensation committee is required to be independent. None of the members of the compensation committee has been determined to be independent at this time. The compensation committee has the sole authority to retain any compensation consultants to be used to assist the committee, but did not retain any consultants in 2006. Similarly, the compensation committee has not delegated any of its authority to subcommittees. The compensation committee has delegated limited authority to the CEO to administer our long-term incentive plans with respect to non-officers.

Governance and Other Committees

We also have a governance committee that periodically reviews our governance guidelines. The charter of our governance committee is available on our website. See Meetings and Other Information. The governance committee currently consists of Messrs. Smith and Symonds, each of whom is independent under the NYSE s listing standards. As a limited partnership, we are not required by the listing standards of the NYSE to have a nominating committee. As discussed above, three of the owners of our general partner each have the right to appoint a director, and Mr. Armstrong is a director by virtue of his office. In the event of a vacancy in the three independent director seats, the governance committee will assist in identifying and screening potential candidates. Upon request of the owners of the general partner, the governance committee is also available to assist in identifying and screening potential candidates for the currently vacant at large seat. The governance committee will base its recommendations on an assessment of the skills, experience and characteristics of the candidate in the context of the needs of the board. As a minimum requirement for the independent board seats, any candidate must be independent and qualify for service on the audit committee under applicable SEC and NYSE rules.

In addition, our partnership agreement provides for the establishment or 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 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.

Meetings and Other Information

During the last fiscal year our board of directors had eight regularly scheduled and special meetings, our audit committee had 14 meetings, our compensation committee had one meeting and our governance committee had two meetings. None of our directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

As discussed above, the corporate governance of GP LLC is, in effect, the corporate governance of our partnership and directors of GP LLC are designated or elected by the members of GP LLC. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement. As a result, we do not hold annual meetings of unitholders.

All of our committees have charters. Our committee charters and governance guidelines, as well as our Code of Business Conduct and our Code of Ethics for Senior Financial Officers, which apply to our principal executive officer, principal financial officer and principal accounting officer, are available on our Internet website at http://www.paalp.com. Print versions of the foregoing are available to any unitholder upon request by writing to our Secretary, Plains All American Pipeline, L.P., 333 Clay Street, Suite 1600, Houston, Texas 77002. We intend to disclose any amendment to or 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 either on our Internet website or in an 8-K filing. Our Chief Executive Officer submitted to the NYSE the most recent annual certification, without qualification, as required by Section 303A.12(a) of the NYSE s Listed Company Manual.

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, is responsible for expressing an opinion on the conformity of the audited financial statements with accounting principles generally accepted in the United States of America 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

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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, 2006 for filing with the SEC.

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

Report of the Compensation Committee

The compensation committee of Plains All American GP LLC reviews and makes recommendations to the board of directors regarding the compensation for the executive officers and directors.

In fulfilling its oversight responsibilities, the compensation committee reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on the reviews and discussions referred to above, the compensation committee recommended to the board of directors that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2006 for filing with the SEC.

David N. Capobianco, Chairman
Gary R. Petersen
Robert V. Sinnott

Compensation Committee Interlocks and Insider Participation

Messrs. Capobianco, Petersen and Sinnott served on the compensation committee during 2006. During 2006, none of the members of the committee was an officer or employee of us or any of our subsidiaries, or served as an officer of any company with respect to which any of our executive officers served on such company s board of directors. In addition, none of the members of the compensation committee are former employees of ours or any of our subsidiaries. Messrs. Capobianco, Petersen and Sinnott are associated with business entities with which we have relationships. See Item 13. Certain Relationships and Related Transactions, and Director Independence.

Directors and Executive Officers

The following table sets forth certain information with respect to the members of our board of directors, our executive officers (for purposes of Item 401(b) of Regulation S-K) and certain other officers of us and our subsidiaries. Directors are elected annually and all executive officers are appointed by the board of directors to serve until their resignation, death or removal. There is no family relationship between any executive officer and director. Three of the owners of our general partner each have the right to separately designate a member of our board. Such designees are indicated in footnote 2 to the following table.

Name	Age (as of 12/31/06)	Position(1)

Greg L. Armstrong*(2)	48	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	49	President and Chief Operating Officer
Phillip D. Kramer*	50	Executive Vice President and Chief Financial Officer
George R. Coiner*	56	Senior Group Vice President

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Name	Age (as of 12/31/06)	Position(1)
W. David Duckett*	51	President PMC (Nova Scotia) Company
Mark F. Shires*	49	Senior Vice President Operations
Alfred A. Lindseth	37	Senior Vice President Technology, Process & Risk Management
D. Mark Alenius	47	Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Stephen L. Bart	46	Vice President Operations of PMC (Nova Scotia) Company
Ralph R. Cross	51	Vice President Business Development and Transportation Services of PMC (Nova Scotia) Company
Lawrence J. Dreyfuss	52	Vice President, General Counsel Commercial & Litigation and Assistant Secretary
Roger D. Everett	61	Vice President Human Resources
James B. Fryfogle	55	Vice President Refinery Supply
Mark J. Gorman	52	Vice President
M.D. (Mike) Hallahan	46	Vice President Crude Oil of PMC (Nova Scotia) Company
Richard (Rick) Henson	52	Vice President Corporate Services of PMC (Nova Scotia) Company
Jim G. Hester	47	Vice President Acquisitions
John Keffer	47	Vice President Terminals
Tim Moore*	49	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	49	Vice President Engineering
John F. Russell	58	Vice President Pipeline Operations
Robert Sanford	57	Vice President Lease Supply
Al Swanson	42	Vice President Finance and Treasurer
Tina L. Val*	37	Vice President Accounting and Chief Accounting Officer
Troy E. Valenzuela	45	Vice President Environmental, Health and Safety
John P. vonBerg*	52	Vice President Trading
David E. Wright	61	Vice President
Ron F. Wunder	38	Vice President LPG of PMC (Nova Scotia) Company
David N. Capobianco(2)	37	Director and Member of Compensation** Committee
Everardo Goyanes	62	Director and Member of Audit** Committee
Gary R. Petersen(2)	60	Director and Member of Compensation Committee
Robert V. Sinnott(2)	57	Director and Member of Compensation Committee
Arthur L. Smith	54	Director and Member of Audit and Governance** Committees

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Name	Age (as of 12/31/06)	Position(1)
J. Taft Symonds	67	Director and Member of Audit and Governance Committees

* Indicates an executive officer for purposes of Item 401(b) of Regulation S-K.

** Indicates chairman of committee.

(1) Unless otherwise described, the position indicates the position held with Plains All American GP LLC.

(2) The GP 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 three of the owners of our general partner each have the right to appoint a member of our board of directors. Mr. Capobianco has been appointed by Vulcan Energy Corporation, of which he is Chairman of the Board. Because it owns a majority in interest in GP LLC, Vulcan Energy Corporation has the power at any time to cause an additional director to be elected to the currently vacant board seat. Mr. Petersen has been appointed by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is Senior Managing Director. Mr. Sinnott has been appointed by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is President. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest.

Greg L. Armstrong has served as Chairman of the Board and Chief Executive Officer since our formation in 1998. 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 National Oilwell Varco, Inc., a director of Breitburn Energy Partners, L.P. and a director of PAA/Vulcan.

Harry N. Pefanis has served as President and Chief Operating Officer since our formation in 1998. 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. Mr. Pefanis is also a director of PAA/Vulcan and Settoon Towing.

Phillip D. Kramer has served as Executive Vice President and Chief Financial Officer since our formation in 1998. 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 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 in 1998 to February 2004. In addition, he was Vice President of Plains Marketing & Transportation Inc. from November 1995 until our formation. Prior to joining Plains Marketing & Transportation Inc., he was Senior Vice President, Marketing with Scurlock Permian LLC. Mr. Coiner is also a director of Settoon Towing.

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 with CANPET Energy Group Inc. from 1985 to 2001, where he served in various capacities, including most recently as President, Chief Executive Officer and Chairman of the Board. Mr. Duckett is also a director of WellPoint Systems Inc.

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.

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.

Stephen L. Bart has been Vice President, Operations of PMC (Nova Scotia) Company since April 2005 and was Managing Director, LPG Operations & Engineering from February to April 2005. From June 2003 to February 2005, Mr. Bart was engaged as a principal of Broad Quay Development, a consulting firm. From April 2001 to June 2003, Mr. Bart served as Chief Executive Officer of Novera Energy Limited, a publicly-traded international renewable energy concern. From January 2000 to April 2003, he served as Director, Northern Development, for Westcoast Energy Inc.

Ralph R. Cross has been Vice President of Business Development and Transportation Services 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.

Lawrence J. Dreyfuss has served as Vice President, General Counsel Commercial & Litigation and Assistant Secretary since August 2006. Mr. Dreyfuss was Vice President, Associate General Counsel and Assistant Secretary of our general partner from February 2004 to August 2006 and 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.

Roger D. Everett has served as Vice President Human Resources since November 2006 and as Director of Human Resources from August 2006 to December 2006. Before joining us, Mr. Everett was a Principal with Stone Partners, a human resource management consulting firm, for over 10 years serving as the Managing Director Human Resources from 2000 to 2006. Mr. Everett has held numerous positions of increasing responsibility in human resource management since 1979 including Vice President of Human Resources at Living Centers of America and Beverly Enterprises, Director of Human Resources at Healthcare International and Director of Compensation and benefits at Charter Medical.

James B. Fryfogle has served as Vice President Refinery Supply since March 2005. He served as Vice President Lease Operations from July 2004 until March 2005. 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.

Mark J. Gorman has served as Vice President since November 2006. Prior to joining Plains, he was with Genesis Energy in differing capacities as a Director, President and CEO, and Executive Vice President and COO from 1996 through August 2006. From 1992 to 1996, he served as a President for Howell Crude Oil Company. Mr. Gorman began his career with Marathon Oil Company, spending 13 years in various disciplines.

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 as 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.

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.

John Keffer has served as Vice President Terminals since November 2006. Mr. Keffer joined Plains Marketing L.P. in October 1998 and prior to his appointment as Vice President, he served as Managing Director Refinery Supply, Director of Trading and Manager of Sales and Trading. Prior to joining Plains Mr. Keffer was with Prebon Energy, an energy brokerage firm, from January 1996 through September 1998. Mr. Keffer was with the Permian Corporation / Scurlock Permian from January 1990 through December 1995, where he served in several capacities in the marketing department including Director of Crude Oil Trading. Mr. Keffer began his career with Amoco Production Company and served in various capacities beginning in June 1982.

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.

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.

John F. Russell has served as Vice President Pipeline Operations since July 2004. Prior to joining us, 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.

Robert Sanford has served as Vice President Lease Supply since June 2006. He served as Managing Director Lease Acquisitions and Trucking from July 2005 to June 2006 and as Director of South Texas and Mid Continent Business Units from April 2004 to July 2005. Mr. Sanford was with Link Energy/EOTT Energy from 1994 to April 2004, where he held various positions of increasing responsibility.

Al Swanson has served as Vice President Finance and Treasurer since August 2005, as Vice President and Treasurer from February 2004 to August 2005 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 since 1992. 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 Trading since May 2003 and Director of these activities since joining us in January 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 E. Wright has served as Vice President since November 2006. Prior to joining Plains, he served as Executive Vice President, Corporate Development for Pacific Energy Partners, L.P. from February 2005 and as Vice President, Corporate Development and Marketing from December 2001. Mr. Wright also served as Vice President, Distribution West of Tosco Refining Company from March 1997 to June 2001, and as Vice President, Pipelines for GATX Terminals Corporation from October 1995 to March 1997.

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.

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 and co-head of Private Equity of Vulcan Capital, an affiliate of Vulcan Inc., where he has been employed since April 2003. Previously, he served as a member of Greenhill Capital from 2001 to April 2003 and Harvest Partners from 1995 to 2001. Mr. Capobianco is Chairman of the board of Vulcan Resources Florida, and is a director of PAA/Vulcan and ICAT Holdings. Mr. Capobianco received a BA in Economics from Duke University and an MBA from Harvard.

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 of our general partner since June 2001. Mr. Petersen is Senior Managing Director of EnCap Investments L.P., an investment management firm which he co-founded in 1988. He is also a director of EV Energy Partners, L.P. 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 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.

Robert V. Sinnott has served as a director of our general partner or former general partner since September 1998. Mr. Sinnott is President, Chief Investment Officer and Senior Managing Director of energy investments of Kayne Anderson Capital Advisors, L.P. (an investment management firm). He also served as a Managing Director from 1992 to 1996 and as a Senior Managing Director from 1996 until assuming his current role in 2005. He is also

President of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. and he is a director of Kayne Anderson Energy Development Company. He was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992. Mr. Sinnott received a BA from the University of Virginia and an MBA from Harvard.

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 holds the CFA designation. He serves on the board of non-profit Dress for Success Houston and the Board of Visitors for the Nicholas School of the Environment and Earth Sciences at Duke University. 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 of our general partner since June 2001. Mr. Symonds is Chairman of the Board of Symonds Trust Co. Ltd. (a private investment firm) and was, until December 2006, Chairman of the Board of Tetra Technologies, Inc. (an oil and gas 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 has a background in both investment and commercial banking, including merchant banking in New York, London and Hong Kong with Paine Webber, Robert Fleming Group and Banque de la Societe Financiere Europeenne. He is Chairman 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 Exchange Act of 1934 requires directors, executive 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 NYSE 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. Such reports are accessible on or through our Internet website at http://www.paalp.com.

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 executive officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2006.

Item 11. *Executive Compensation*

Compensation Discussion and Analysis

Background

All of our officers and employees (other than Canadian personnel) are employed by Plains All American GP LLC. Our Canadian personnel are employed by PMC (Nova Scotia) Company, which is a wholly owned subsidiary. Under our partnership agreement, we are required to reimburse our general partner and its affiliates for all employment-related costs, including compensation for executive officers.

Objectives

Since our inception, we have employed a compensation philosophy that emphasizes pay for performance, both on an individual and entity level, and places the majority of each Named Executive Officer s (defined below) compensation at risk. The primary long-term measure of the Partnership s performance is its ability to increase its sustainable quarterly distribution to its unitholders. We believe our pay-for-performance approach aligns the interests of executive officers with that of our unitholders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance is below expectations. Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our unitholders, and to reward success in reaching such goals. We use three primary elements of compensation to fulfill that design salary, cash bonus and long-term equity incentive awards. In practice, our salaries are moderate relative to the broad spectrum of energy industry competitors for similar talent, but are generally competitive with the narrower universe of large-cap MLP peers. The determination of specific individuals cash bonus is based on their relative contribution to achieving or exceeding annual goals and the determination of specific individuals long-term incentive awards is based on their expected contribution in respect of longer term performance benchmarks. Cash bonuses and equity incentives (as opposed to salary) represent the truly performance-driven elements. They are also flexible in application and can be tailored to serve more than one purpose. We do not maintain a defined benefit or pension plan for our executive officers as we believe such plans primarily reward longevity and not performance. We provide a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance. In instances considered necessary for the execution of their job responsibilities, we also reimburse certain of our executive officers and other employees for club dues and similar expenses. We consider these benefits and reimbursements to be typical of other employers, and we do not believe they are distinctive of our compensation program.

Elements of Compensation

Salary. We do not benchmark our salary or bonus amounts. In practice, our salaries are moderate relative to the broad spectrum of energy industry competitors for similar talent, but are generally competitive with the narrower universe of large-cap MLP peers.

Cash Bonuses. Our cash bonuses consist of annual discretionary bonuses in which all Named Executive Officers potentially participate and a formula-based quarterly bonus program in which Messrs. Coiner and vonBerg participate.

Long-Term Incentive Awards. The primary long-term measure of the Partnership s performance is its ability to increase its sustainable quarterly distribution to its equity holders. The Partnership uses performance-indexed phantom unit grants to encourage and reward timely achievement of targeted distribution levels and align the long-term interests of the Named Executive Officers with those of the Partnership s equity owners. These grants also contain minimum service periods as further described below in order to encourage long-term retention. A phantom unit is the right to receive, upon the satisfaction of any vesting criteria specified in the grant, a common unit (or cash equivalent) of the Partnership. The Partnership does not use options as a form of incentive compensation. Unlike vesting of an option, vesting of a phantom unit results in delivery of a common unit or cash of equivalent value as opposed to a right to exercise. Terms of historical phantom unit grants have varied, but generally phantom units vest upon the later of achievement of targeted distribution threshold levels and continued employment for periods ranging from two to six years. These distribution performance thresholds are generally consistent with the Partnership s targeted range for distribution growth. To encourage accelerated performance, if the Partnership meets certain distribution thresholds prior to meeting the minimum service requirement for vesting, the named executive officers have the right to receive distributions on phantom unit grants prior to vesting in the underlying units (referred to as distribution equivalent rights, or DERs).

Relation of Compensation Elements to Compensation Objectives

Our compensation program is designed to motivate, reward and retain our executive officers. Cash bonuses serve as a near-term motivation and reward for achieving the annual goals established at the beginning of each year. Phantom unit awards and associated DERs provide motivation and reward over both the near-term and long-term for achieving performance thresholds necessary for vesting. The level of annual bonus and phantom unit awards reflect the moderate salary profile and the significant weighting towards performance-based, at-risk compensation. Salaries and cash bonuses (particularly quarterly bonuses), as well as currently payable DERs associated with unvested phantom units, serve as near-term retention tools. Longer-term retention is facilitated by the minimum service periods of up to five years associated with phantom unit awards and, in the case of Mr. Coiner and Mr. vonBerg, annual bonuses that are payable over a three-year period. To facilitate the compensation committee in reviewing and making recommendations with respect to compensation of Named Executive Officers, the committee is provided a compensation tally sheet for such officers.

We stress performance-based compensation elements to attempt to create a performance-driven environment in which our executive officers are (i) motivated to perform over both the short term and the long term,

(ii) appropriately rewarded for their services and (iii) encouraged to remain with the Partnership even after meeting long-term performance thresholds in order to meet the minimum service periods and by the promise of rewards yet to come. We believe our compensation philosophy as implemented by application of the three primary compensation elements aligns the interests of the Named Executive Officers with our equity holders and positions the Partnership to achieve its business goals.

We believe these compensation practices have been successful in achieving our objectives. Over the five-year period ended December 31, 2006, our annual distribution per limited partner unit has grown at a compound annual rate of 8.3% and the total return realized by our limited partner unitholders for that period averaged approximately 23%. Our retention rate for Named Executive Officers over the same period has been 100%.

Application of Compensation Elements

Salary. We do not make systematic annual adjustments to the salaries of the Named Executive Officers. Instead, when indicated as a result of adding new senior management members to keep pace with our overall growth, necessary salary adjustments are made to maintain hierarchical relationships between senior management levels and the new senior management members. Since May 1999, Messrs. Armstrong and Pefanis have received one salary adjustment and Messrs. Coiner and Kramer have received two salary adjustments.

Cash Bonuses.

Annual Discretionary Bonuses. Annual discretionary bonuses are determined based on the Partnership s performance relative to its annual plan forecast and public guidance, its distribution growth targets and other quantitative and qualitative goals established at the beginning of each year. Such annual objectives are discussed and reviewed with the board in conjunction with the review and authorization of the annual plan.

At the end of each year, our CEO performs a quantitative and qualitative assessment of the Partnership s performance relative to its goals. Key quantitative measures include earnings before interest, taxes, depreciation and amortization, excluding items affecting comparability (EBITDA), relative to established guidance, as well as the growth in the annualized quarterly distribution level per limited partner unit relative to annual growth targets. Our primary performance metric is our ability to generate increasing and sustainable cash distributions to our equity owners. Accordingly, although net income and net income per unit are monitored to highlight inconsistencies with primary performance metrics, as is the Partnership s market performance relative to our MLP peers and major indices, these metrics are considered secondary performance measures. Our CEO s written analysis of our performance examines the Partnership s accomplishments, shortfalls and overall performance against opportunity, taking into account controllable and non-controllable factors encountered during the year.

The resulting document and supporting detail is submitted to our board of directors for review and comment. Based on the conclusions set forth in the annual performance review, our CEO submits recommendations to the compensation committee for bonuses to Named Executive Officers, taking into account the relative contribution of the individual officer. Except as described below for Messrs. Coiner and vonBerg, there are no set formulas for determining the annual discretionary bonus for Named Executive Officers. Factors considered by our CEO in determining the level of bonus in general include (i) whether or not we achieved the goals established for the year and any notable shortfalls relative to expectations; (ii) the level of difficulty associated with achieving such objectives based on the opportunities and challenges encountered during the year; (iii) current year operating and financial performance relative to both public guidance and prior year s performance; (iv) significant transactions or accomplishments for the period not included in the goals for the year; (v) our relative prospects at the end of the year with respect to future growth and performance; and (vi) our positioning at the end of the year with respect to our targeted credit profile. Our CEO takes these factors into consideration as well as the relative contributions of each of the Named Executive Officers to the year s performance in developing his recommendations for bonus amounts.

These recommendations are discussed with the compensation committee, adjusted as appropriate, and submitted to the board for its review and approval. Similarly, the compensation committee assesses the CEO s contribution toward meeting the Partnership s goals, and recommends a bonus for the CEO it believes to be commensurate with such contribution. In several instances, the CEO has requested that the bonus amount recommended by the compensation committee be reduced to maintain a closer relationship to bonuses awarded to the other Named Executive Officers.

Quarterly Bonus based on Adjusted EBITDA. Mr. Coiner, Mr. vonBerg and certain other members of our U.S. based senior management team are directly involved in activities that generate earnings for the Partnership. These individuals, along with approximately 80 other employees in our marketing and business development groups participate in a quarterly bonus pool based on adjusted EBITDA,[1] which directly rewards for quarterly performance the commercial and asset-managing employees who participate. This quarterly incentive provides a direct incentive to optimize quarterly performance even when, on an annual basis, other factors might negatively affect bonus potential. Allocation of quarterly bonus amounts among all participants based on relative contribution is recommended by Mr. Coiner and reviewed, modified and approved by Mr. Pefanis, as appropriate. Mr. Pefanis does not participate in the quarterly bonus. The quarterly bonus amounts for Mr. Coiner and Mr. vonBerg are taken into consideration in determining the recommended annual discretionary bonus submitted by the CEO to the compensation committee.

Long-Term Incentive Awards. The Partnership does not make systematic annual phantom unit awards to the Named Executive Officers. Instead, our objective is to time the granting of awards such that as performance thresholds are met for existing awards, additional long-term incentives are created. Thus, performance is rewarded by relatively greater frequency of awards and lack of performance by relatively lesser frequency of awards. Generally, we believe that a three- to four-year grant cycle (and extended time-vesting requirements) provides a balance between a meaningful retention period for us and a visible, reachable reward for the executive officer. Achievement of performance targets does not shorten the minimum service period requirement. If top performance targets on outstanding awards are achieved in the early part of this four-year cycle, new awards are granted with higher performance thresholds, and the minimum service periods of the new awards are generally synchronized with the remaining time-vesting requirements of outstanding awards in a manner designed to encourage extended retention of the Named Executive Officers. Accordingly, these new arrangements inherently take into account the value of awards where performance levels have been achieved but have not yet vested due to ongoing service period requirements, but do not take into consideration previous awards that have fully vested.

Application in 2006

At the beginning of 2006, the Partnership publicly established the following five goals for 2006:

1. Deliver operating and financial performance in line with guidance furnished at the beginning of 2006 on a Form 8-K dated February 23, 2006;

2. Maintain and improve our present credit rating and further expand our liquidity and financial flexibility to accommodate future growth;

3. Optimize our existing asset base and operations and expand our inventory of internal expansion projects;

4. Pursue our target of averaging $200 to $300 million of accretive and strategic acquisitions; and

5. Increase our distribution paid to unitholders by 10% over 2005 payments.

The Partnership met or substantially exceeded each of these goals in 2006. Excluding the impact of unforecasted acquisitions, our adjusted EBITDA exceeded the original guidance for 2006 by approximately 24%. Including the impact of unforecasted acquisitions, our adjusted EBITDA exceeded original guidance for 2006 by approximately 40%. We exceeded our acquisition target for 2006 by completing seven acquisitions aggregating approximately $3.0 billion. We also took several steps to optimize our asset base and expand our inventory of organic growth projects as we successfully implemented an expanded capital program totaling approximately $332 million, an increase of 44% as compared to the original capital program for 2006 of approximately

[1] Adjusted EBITDA excludes the effect of certain non-cash items such as the effect of FAS 133 and accrual of LTIP expenses. Any bonus amounts that are deducted in calculating EBITDA are added back for purposes of calculating the bonus pool.

$230 million. Despite a year of significant acquisition and expansion activity, we maintained a strong capital structure and an investment grade credit rating and expanded the Partnership s liquidity and financial flexibility. Finally, we exceeded our goal for unitholder distributions as total distributions paid in 2006 increased by approximately 11.5% over distributions paid in 2005. The total return to our limited partners (unit price appreciation plus distributions received) was approximately 38% in 2006 as compared to 25.8%, 15.8% and 19.0% for the MLP peer index, the S&P 500 and the Dow Jones Industrial Index, respectively.

For 2006, the elements of compensation were applied as follows:

Salary. No salary adjustments were recommended or made in 2006.

Cash Bonuses. Based on our CEO s annual performance review and the individual performance of each of our Named Executive Officers, our compensation committee recommended to the board and the board approved the annual bonuses reflected in the Summary Compensation Table and notes thereto. The aggregate annual and, where applicable, quarterly bonus amounts reflected in the Summary Compensation Table are approximately 11% to 28% higher than amounts paid in 2005, which was considered a year of strong performance. Such amounts take into account the significant overperformance relative to each of the five goals established for 2006, the absence of any notable shortfalls relative to expectations; the level of difficulty associated with achieving such objectives; our relative positioning at the end of the year with respect to future growth and performance; the significant transactions or accomplishments for the period not included in the goals for the year; and our positioning at the end of the year with respect to our targeted credit profile. In the case of Mr. Coiner and Mr. vonBerg, the aggregate bonus amount represented 39.8% and 37.5% in annual bonus and 60.2% and 62.5% in quarterly bonus, respectively.

Long-Term Incentive Awards. No awards were made in 2006. Effective with the November 2006 distribution, however, we achieved the highest performance threshold ($3.00 per limited partner unit annualized) contained in substantially all pre-2006 phantom unit awards. Vesting of these pre-2006 awards remains subject to continued employment, and the service-period vesting requirements will be met in various increments over the next three to four years with the final vesting in May 2010. The compensation expense recognized in 2006 related to such awards is reflected on an individual basis in the Summary Compensation Table that follows. The vesting requirements are described in the footnotes to the Outstanding Equity Awards Table that follows.

Consistent with our policy of issuing new grants (with extended time-vesting periods) when the highest performance threshold of existing grants has been reached, in February of 2007 our board of directors granted awards with a top performance threshold of $4.00 per limited partner unit, representing a 33% increase over the November 2006 distribution level of $3.00 per unit. Such grants are intended to encourage continued growth and fundamental performance that will support future distribution growth. Specifically, the terms of the awards provide that, subject to meeting the service period requirement, the phantom unit grants will vest in one-third increments upon achieving annualized quarterly distribution levels of $3.50 per unit, $3.75 per unit and $4.00 per unit, respectively. Tandem DERs vest in 25% increments upon achieving annualized quarterly distribution levels of $3.40, $3.60, $3.80 and $4.00 per unit. Approximately two-thirds of the awards are eligible to vest in 2011 and one-third are eligible to vest in 2012. If any of the performance thresholds are not achieved prior to the May 2014 distribution date, such awards will expire. Upon vesting, the phantom units are payable on a one-for-one basis in common units of the partnership (or cash equivalent depending on the form of grant). The 2007 awards included grants to the Named Executive Officers as follows: Mr. Armstrong, 180,000; Mr. Pefanis, 120,000; Mr. Kramer, 60,000; Mr. Coiner, 90,000 and Mr. vonBerg, 54,000. The number of phantom units awarded to the Named Executive Officers represents approximately 60% of their outstanding pre-2006 awards.

Other Compensation Related Matters

Equity Ownership. As of December 31, 2006, each of the Named Executive Officers owned substantial equity in the partnership. Although the Partnership encourages its Named Executive Officers to retain ownership in the Partnership, it does not have a policy requiring maintenance of a specified equity ownership level. The Partnership s policies prohibit the Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership. In the aggregate, as of December 31, 2006, the Named Executive Officers beneficially owned an aggregate of approximately 556,475 limited partner units, excluding any unvested equity awards, as well as an aggregate 3% indirect ownership interest in the general partner. Based on the market price of the limited partner units at December 31, 2006 and an implied valuation for their collective general partner interest using similar valuation metrics, the value of the equity ownership of these individuals was approximately 45 times their aggregate 2006 salaries and approximately 3.9 times the combined aggregate salaries and bonuses for 2006.

Recovery of Prior Awards. Except as provided by applicable laws and regulations, the Partnership does not have a policy with respect to adjustment or recovery of awards or payments if relevant company performance measures upon which previous awards were based are restated or otherwise adjusted in a manner that would reduce the size of such award or payment.

Section 162(m). With respect to the deduction limitations under Section 162(m) of the Code, Plains is a limited partnership and does not meet the definition of a corporation under Section 162(m). Nonetheless, the salaries for each of the Named Executive Officers are substantially less than the Section 162(m) threshold of $1,000,000 and we believe the bonus compensation and long-term incentive compensation would qualify for performance-based compensation under Reg. 1.162-27(e) and therefore would not be additive to salaries for purposes of measuring the $1,000,000 tax limitation.

Change in Control Triggers. The employment agreements for Messrs. Armstrong and Pefanis and the long-term incentive plan grants to the Named Executive Officers include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreement. In the case of the long-term incentive plan grants, the provision becomes operative only if the change in control is accompanied by a change in status (such as the termination of employment by the general partner). We believe this double trigger arrangement is appropriate because it provides assurance to the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The provisions in the employment agreements for Messrs. Armstrong and Pefanis become operative only if the executive terminates employment within three months of the change in control. Messrs. Armstrong and Pefanis agreed to a conditional waiver of these provisions with respect to a transaction in 2005 that would have constituted a change in control. See Potential Payments upon Termination or Change-in-Control and Employment Agreements.

Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer, Chief Financial Officer and the three other most highly compensated executive officers in 2006 (the Named Executive Officers). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation.

2006 Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong Chairman and CEO	2006	375,000	3,750,000	5,184,222	0	15,930	9,325,152

Harry N. Pefanis President and Chief Operating Officer	2006	300,000	3,400,000	3,456,148	0	15,930	7,172,078
Phillip D. Kramer Executive Vice President and Chief Financial Officer	2006	250,000	1,000,000	1,876,043	0	15,930	3,141,973
George R. Coiner Senior Group Vice President	2006	250,000	3,390,100(3)	2,616,477	0	15,930	6,272,507
John P. vonBerg Vice President Trading	2006	200,000	2,934,700(4)	1,575,530	0	15,744	4,725,974

(1) Dollar amounts represent the compensation expense recognized in 2006 with respect to outstanding phantom unit grants under our LTIP, whether or not granted during 2006. See Note 10 to our Consolidated Financial

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Statements for a discussion of the assumptions made in determining these amounts. While substantially all of the performance thresholds for earning the phantom units represented by these amounts had been met as of December 29, 2006, none of the amounts included in this column were vested as of such date as they contain ongoing service requirements and, subject to meeting those requirements, will vest in various increments in 2007, 2008, 2009 and 2010.

(2) Our general partner matches 100% of employees contributions to its 401(k) plan in cash, subject to certain limitations in the plan. All Other Compensation for Messrs. Armstrong, Pefanis, Kramer, Coiner and vonBerg includes $15,000 in such contributions. The remaining amount represents premium payments on behalf of the Named Executive Officer for group term life insurance.

(3) Includes quarterly bonuses aggregating $2,040,100 and an annual bonus of $1,350,000. The annual bonus is payable 60% at the time of award and 20% in each of the two succeeding years.

(4) Includes quarterly bonuses aggregating $1,834,700 and an annual bonus of $1,100,000. The annual bonus is payable 60% at the time of award and 20% in each of the two succeeding years.

Grants of Plan-Based Awards Table

This table has been omitted because no plan-based awards were made in 2006. See Compensation Discussion and Analysis.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

A discussion of 2006 salaries and bonuses is included in Compensation Discussion and Analysis. The following is a discussion of other material factors necessary to an understanding of the information disclosed in the Summary Compensation Table.

2006 Salary As discussed in our CD&A, we do not make systematic annual adjustments to the salaries of the Named Executive Officers. Accordingly, no salary adjustments were made for any of our executive officers in 2006.

Employment Contracts

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, including, but not limited to, requirement of law or prior disclosure by a third party) 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 2005, Mr. Armstrong s annual salary was increased to $375,000. See Compensation Discussion and Analysis for a discussion of how salary and bonus are used to achieve compensation objectives. See Potential Payments Upon Termination or Change-In-Control for a discussion of the provisions in Mr. Armstrong s employment agreement related to termination, change of control and related payment obligations.

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 2005, Mr. Pefanis annual salary was increased to $300,000. See Compensation Discussion and Analysis for a discussion of how salary and bonus are used to achieve compensation objectives. See Potential Payments Upon Termination or Change-In-Control for a discussion of the provisions in Mr. Pefanis employment agreement related to termination, change of control and related payment obligations.

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In connection with Mr. vonBerg s employment in January 2002, our general partner and Mr. vonBerg entered into a letter agreement setting forth the terms of his employment. Such letter agreement provided for Mr. vonBerg s position to be Director, Trading at a base salary of $200,000 per year and his participation in a quarterly bonus pool based on gross margin generated by the employee s business unit, discretionary annual bonus pool and employee benefits provided to all employees generally. See Compensation Discussion and Analysis for a discussion of how salary and bonus are used to achieve compensation objectives. The letter agreement expired in accordance with its terms in January 2007. Mr. vonBerg also entered into an ancillary agreement which provides that for a period of one year following his termination, he will not disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement and he will not, for one year after termination, engage in certain transactions with certain suppliers and customers.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2006 with respect to the Named Executive Officers:

Outstanding Equity Awards at Fiscal Year-End

	Option Awards					Stock Awards			
Name (a)	**Number of Securities Underlying Unexercised Options (#) Exercisable (b)**	**Number of Securities Underlying Unexercised Options (#) Unexercisable (c)**	**Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)**	**Option Exercise Price ($) (e)**	**Option Expiration Date (f)**	**Number of Shares or Units of Stock that Have Not Vested (#) (g)**	**Market Value of Shares or Units of Stock that Have Not Vested ($) (h)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested (#) (i)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1) (j)**
Greg L. Armstrong	37,500(2)			$ 11.55	06/07/2011			300,000(3)	15,360,000
Harry N. Pefanis	27,500(2)			$ 11.55	06/07/2011			200,000(3)	10,240,000
Phillip D. Kramer	22,500(2)			$ 11.55	06/07/2011			100,000(4)	5,120,000

George R. Coiner	21,250(2)	$ 11.55	06/07/2011		
				80,000(4)	4,096,000
				70,000(5)	3,584,000
John P. vonBerg				50,000(4)	2,560,000
				40,000(5)	2,048,000

(1) Market value of stock reported in this column is calculated by multiplying the closing market price ($51.20) of the Partnership s common units at December 29, 2006 (the last trading day of the fiscal year) by the number of units. Approximately one third of the value reflected in this column is also reflected in the Summary Compensation Table.

(2) The units underlying the options were contributed to our general partner by its owners. We have no obligation to reimburse our general partners for the units upon exercise of the options. Mr. Armstrong vested in 18,750 options on April 22, 2002 and 18,750 options on July 21, 2004. Mr. Pefanis vested in 13,750 options on each of the same dates. Mr. Kramer vested in 11,250 options on each of the same dates. Mr. Coiner vested in 10,625 options on each of the same dates.

(3) These phantom units will vest 30%, 30% and 40% solely upon achievement by the Partnership of annualized distributions of $2.60, $2.80 and $3.00 per unit and continued employment through May 2007, May 2009 and May 2010, respectively. Any phantom units that have not vested (and all associated DERs) as of the May 2012 distribution date will be forfeited. DERs associated with these phantom units become payable 30%, 15%, 15%,

20% and 20% upon the earlier to occur of annualized distributions of $2.60 or May 2007, $2.70 or May 2008, $2.80 or May 2009, $2.90 or May 2010, and $3.00 or May 2010, respectively.

(4) These phantom units will vest 40%, 30% and 30% upon achievement by the Partnership of annualized distributions of $2.60, $2.80 and $3.00 per unit and continued employment through May 2007, May 2009 and May 2010, respectively. Any phantom units that have not previously vested will fully vest on the May 2011 distribution date, subject to continued employment through such date. DERs associated with these phantom units become payable 40%, 15%, 15%, 15% and 15% upon the earlier to occur of annualized distributions of $2.60 or May 2007, $2.70 or May 2008, $2.80 or May 2009, $2.90 or May 2010, and $3.00 or May 2010, respectively.

(5) These phantom units will vest in equal one-third increments solely upon achievement by the Partnership of annualized distributions of $2.90, $3.00 and $3.10 per unit and continued employment through May 2008, May 2009 and May 2010, respectively. DERs associated with these phantom units vest and become payable in equal one-third increments solely upon the payment of annualized distributions of $2.90, $3.00, and $3.10, respectively. Any phantom units that have not vested (and all associated DERs) as of the May 2012 distribution date will be forfeited.

Option Exercises and Stock Vested Table

This table has been omitted because there were no exercises of options by or vestings of LTIPs for the Named Executive Officers in 2006.

Pension Benefits

The Partnership sponsors a 401(k) plan that is available to all U.S. employees, but does not maintain a pension or defined benefit program.

Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans

The Partnership does not have a nonqualified deferred compensation plan or program for its officers or employees.

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Potential Payments upon Termination or Change-in-Control

The following table sets forth potential amounts payable to our current Named Executive Officers upon termination of employment under various circumstances, and as if terminated on December 29, 2006.

Potential Payments upon Termination or Change-in-Control

Termination:	By Reason of Death ($)	By Reason of Disability ($)	By Company without Cause ($)	By Executive with Good Reason ($)	In Connection with a Change in Control ($)
Greg L. Armstrong					
Salary and Bonus	6,750,000(1)	6,750,000(1)	6,750,000(1)	6,750,000(1)	10,125,000(2)
Equity Compensation	15,360,000(3)	15,360,000(3)	15,360,000(2)(4)	15,360,000(2)	15,360,000(2)(5)
Health Benefits	N/A	39,736(6)	39,736(6)	39,736(6)	39,736(6)
Tax Gross-up	N/A	N/A	N/A	N/A	2,371,479(7)
Total	22,110,000	22,149,736	22,149,736	22,149,736	27,896,215
Harry N. Pefanis					
Salary and Bonus	6,100,000(1)	6,100,000(1)	6,100,000(1)	6,100,000(1)	9,150,000(2)
Equity Compensation	10,240,000(3)	10,240,000(3)	10,240,000(4)	10,240,000(2)	10,240,000(2)(5)
Health Benefits	N/A	39,736(6)	39,736(6)	39,736(6)	39,736(6)
Tax Gross-up	N/A	N/A	N/A	N/A	2,112,233(7)
Total	16,340,000	16,379,736	16,379,736	16,379,736	21,541,969
Phillip D. Kramer					
Equity Compensation	5,120,000(3)	5,120,000(3)	5,120,000(4)	N/A	5,120,000(5)
George R. Coiner					
Equity Compensation	7,680,000(3)	7,680,000(3)	6,485,299(4)	N/A	7,680,000(5)
John P. vonBerg					
Equity Compensation	4,608,000(3)	4,608,000(3)	3,925,299(4)	N/A	4,608,000(5)

(1) The employment agreements between our general partner and Messrs. Armstrong and Pefanis provide that if (i) their employment with our general partner is terminated as a result of their death, (ii) they terminate their employment with our general partner (a) because of a disability (as defined below) or (b) for good reason (as defined below), or (iii) our general partner terminates their employment without cause (as defined below), they are entitled to a lump-sum amount equal to the product of (1) the sum of their (a) highest annual base salary paid prior to their date of termination and (b) highest annual bonus paid or payable for any of the three years prior to the date of termination, and (2) the lesser of (i) two or (ii) the number of days remaining in the term of their employment agreement divided by 360. The amount provided in the table assumes for each executive a termination date of December 29, 2006, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $3,000,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $2,750,000 for Mr. Pefanis.

The employment agreements between our general partner and Messrs. Armstrong and Pefanis define disability as the impairment of health to an extent that makes the continued performance of their duties hazardous to physical or mental health or life.

The employment agreements between our general partner and Messrs. Armstrong and Pefanis define cause as (i) willfully engaging in gross misconduct, or (ii) conviction of a felony involving moral turpitude. Notwithstanding, no act, or failure to act, on their part is willful unless done, or omitted to be done, not in good faith and without reasonable belief that such act or omission was in the best interest of our general partner or otherwise likely to result in no material injury to our general partner. However, neither Mr. Armstrong or Mr. Pefanis will be deemed to have been terminated for cause unless and until there is delivered to them a copy of a resolution of the board of directors of our general partner at a meeting held for that purpose (after reasonable notice and an opportunity to be heard), finding that Mr. Armstrong or Mr. Pefanis, as applicable, was guilty of the conduct described above, and specifying the basis for that finding.

The employment agreements between our general partner and Messrs. Armstrong and Pefanis define good reason as the occurrence of any of the following circumstances: (i) removal by our general partner from, or failure to re-elect them to, the positions to which Messrs. Armstrong and Pefanis were appointed pursuant to their respective employment agreements, except in connection with their termination for cause (as defined above); (ii) (a) a reduction in their rate of base salary (other than in connection with across-the-board salary reductions for all executive officers of our general partner, unless such reduction reduces their base salary to less than 85% of their current base salary, (b) a material reduction in their fringe benefits, or (c) any other material failure by our general partner to comply with its obligations under their employment agreements to pay their annual salary and bonus, reimburse their business expenses, provide for their participation in certain employee benefit plans and arrangements, furnish them with suitable office space and support staff, or allow them no less than 15 business days of paid vacation annually; or (iii) the failure of our general partner to obtain the express assumption of the employment agreements by a successor entity (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of our general partner.

(2) Pursuant to their employment agreements, if Messrs. Armstrong and Pefanis terminate their employment with our general partner within three (3) months of a change in control (as defined below), they are entitled to a lump-sum payment in an amount equal to the product of (i) three and (ii) the sum of (a) their highest annual base salary previously paid to them and (b) their highest annual bonus paid or payable for any of the three years prior to the date of such termination. The amount provided in the table assumes a change in control and termination date of December 29, 2006, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $3,000,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $2,750,000 for Mr. Pefanis.

For this purpose a change in control means (i) the acquisition by an entity or group (other than Plains Resources Inc. or a wholly owned subsidiary thereof) of 50% or more of the membership interest of our general partner or (ii) the existing owners of the membership interests of our general partner ceasing to own more than 50% of the membership interests of our general partner.

In August 2005, Vulcan Energy increased its interest in our general partner from approximately 44% to approximately 54%. The consummation of the transaction constituted a change of control under the employment agreements with Messrs. Armstrong and Pefanis. However, Messrs. Armstrong and Pefanis entered into agreements with our general partner waiving their rights to payments under their employment agreements in connection with the change of control, contingent on the execution and performance by Vulcan Energy of a voting agreement with GP LLC that restricts certain of Vulcan s voting rights. Upon a breach, termination, or notice of termination of the voting agreement by Vulcan Energy these waivers will automatically terminate and the executive officer will be paid a lump sum as if he had terminated his employment for good reason. Upon any termination by the Company without cause or by the executive for good reason, such executive officer would also vest in all outstanding phantom units under our LTIPs.

(3) The letters evidencing the 2005 phantom unit grants to the Named Executive Officers provide that in the event of their death or disability (as defined below), all of their then outstanding phantom units and associated DERs will be deemed 100% nonforfeitable, and such phantom units and associated DERs will vest (*i.e.*, the phantom units will become payable in the form of one common unit and the associated DERs will become payable in a cash lump-sum payment) as provided in Footnote 3 to the Outstanding Equity Awards at Fiscal Year-End table. For this purpose disability means a physical or mental disability that impairs the ability to perform duties for a period of eighteen (18) months or that the general partner otherwise determines constitutes a disability.

The dollar value amount provided assumes the death or disability occurred on December 29, 2006. As a result, all phantom units and the associated DERs of the Named Executive Officers would have become nonforfeitable effective as of December 29, 2006, and vested at the time(s) described in Footnote 3 to the Outstanding Equity Awards at Fiscal Year-End table. The dollar value given is based on the market value on December 29, 2006 ($51.20 per unit) without discount for vesting period.

(4) Pursuant to the 2005 phantom unit grants to the Named Executive Officers, in the event their employment is terminated other than in connection with a change in control (as defined in Footnote 5, below) or by reason of death or disability (as defined in Footnote 3, above), all of the DERs (regardless of vesting) and phantom units then outstanding under their respective 2005 phantom unit grants would automatically be forfeited as of the date of termination; provided, however, that if our general partner terminated their employment other than for cause (as defined below), any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would be deemed nonforfeitable and would vest on the next following distribution date. The dollar value amount provided assumes that the Named Executive Officers were terminated without cause on December 29, 2006. As a result, all of the outstanding phantom units held by Messrs. Armstrong, Pefanis and Kramer would be deemed nonforfeitable and would vest on the February 2007 distribution date. All outstanding phantom units, except for 23,334 and 13,334 held by Messrs. Coiner and vonBerg, respectively, would be deemed nonforfeitable and would vest on the February 2007 distribution date. The dollar value given is based on the market value on December 29, 2006 of $51.20 per unit, without discount for vesting period.

(5) The 2005 phantom unit grants to the Named Executive Officers provide that in the event of a change of status (as defined below), all of the then outstanding phantom units and tandem DERs will be deemed 100% nonforfeitable, and such phantom units will vest in full (*i.e.*, become payable in the form of one common unit of our general partner for each phantom unit) upon the next distribution date. Assuming the change in status occurred on December 29, 2006, all outstanding phantom units and the associated DERs would have become nonforfeitable as of December 29, 2006, and such phantom units and tandem DERs would vest (*i.e.*, become payable) on the February 2007 distribution date.

The phrase change in status means, with respect to a Named Executive Officer, the occurrence, during the period beginning three months prior to and ending one year following a change of control (as defined below), of any of the following: (i) termination of employment by our general partner other than a termination for cause (as defined below); (ii) without consent, the removal from, or any failure to re-elect them to, the position(s) held by them (or substantially equivalent position(s)) immediately prior to the change in control; (iii) any reduction in their base salaries; or (iv) any material reduction in their fringe benefits.

The phrase change of control means, and is deemed to have occurred upon the occurrence of, one or more of the following events; (i) GP LLC ceasing to be the general partner of our general partner; (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Partnership or GP LLC to any person and/or its affiliates, other than to the Partnership or GP LLC, including any employee benefit plan thereof; (iii) the consolidation, reorganization, merger, or any other similar transaction involving (A) a person other than the Partnership or GP LLC and (B) the Partnership, GP LLC or both; (iv) the persons who own membership interests in GP LLC ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of GP LLC; or (v) any person, including any partnership, limited partnership, syndicate or other group deemed a person for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becoming the beneficial owner, directly or indirectly, of more than 49.9% of the membership interest in GP LLC. With respect to the lattermost event, the grant letter makes an exception for any existing member of GP LLC if the member signs a voting agreement such as that executed by Vulcan in August 2005 (such exception not applying to the November 2005 grants to Messrs. Coiner and vonBerg).

The term cause means (i) the failure to perform a job function in accordance with standards described in writing, or (ii) the violation of our general partner s Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described in writing.

(6) Pursuant to their employment agreements with our general partner, if Messrs. Armstrong or Pefanis are terminated other than (i) for cause (as defined in Footnote 1, above), (ii) by reason of death or (iii) by resignation (unless such resignation is due to a disability or for good reason (each as defined in Footnote 1, above)), then they are entitled to continue to participate, for a period which is the lesser of two years from the date of termination or the remaining term of the employment agreement, in such health and accident plans or arrangements as is made available by our general partner to its executive officers generally. The amounts provided in the table assume a termination date of December 29, 2006.

(7) Pursuant to their employment agreements, Messrs. Armstrong and Pefanis will be reimbursed for any excise tax due under Section 4999 of the Code as a result of compensation (parachute) payments made under their respective employment agreements. The range of values of this benefit assumes that Messrs. Armstrong and Pefanis were terminated in connection with a change in control effective as of December 29, 2006.

Confidentiality, Non-compete and Non-solicitation Arrangements

Pursuant to his employment agreement, Mr. Armstrong has agreed to maintain the confidentiality of company information for a period of five years after the termination of his employment. Mr. Pefanis has agreed to a similar restriction for a period of one year following the termination of his employment. Mr. Coiner has agreed to maintain confidentiality and not to solicit customers or employees for a period of two years after the termination of his employment. Mr. vonBerg has agreed to maintain confidentiality and not to solicit customers for a period of one year following termination of his employment.

Compensation of Directors

The following table sets forth a summary of the compensation we paid to our non-employee directors in 2006:

Director Compensation

Name (a)	Fees Earned or Paid in Cash ($) (b)	Stock Awards(1) ($) (c)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (f)	All Other Compensation ($) (g)	Total ($) (h)
David N. Capobianco(2)	47,000	101,352					148,352
Everardo Goyanes	75,000	204,482					279,482
Gary R. Petersen(2)	45,000	101,352					146,352
Robert V. Sinnott	45,000	101,352					146,352
Arthur L. Smith	62,000	204,482					266,482
J. Taft Symonds	60,000	204,483					264,483

(1) During the last fiscal year, Messrs. Goyanes, Smith and Symonds were granted 2,500 units and Mr. Sinnott was granted 1,250 units, by virtue of the automatic re-grant of LTIP awards vested during the fiscal year. In addition, each member of the audit committee was awarded 5,000 units, which vest annually in 25% increments; these units are also subject to an automatic re-grant of the amount vested such that in each future fiscal year 1,250 units will simultaneous vest and be re-granted. Upon any vesting (other than the incremental audit

committee awards), a cash equivalent payment is made to Vulcan Capital and an affiliate of EnCap as directed by Mr. Capobianco and Mr. Petersen, respectively. Each audit committee member (currently Messrs. Goyanes, Smith and Symonds) has 10,000 units outstanding. Because these awards are subject to an automatic re-grant of units upon any vesting, each audit committee member will always have outstanding an award of 10,000 units. Mr. Sinnott has 5,000 units outstanding, and because this award is subject to an automatic re-grant of units upon any vesting, Mr. Sinnott will always have outstanding an award of 5,000 units. The dollar value of these awards and other awards granted in prior years is presented in the table reflecting the dollar amount of compensation expense recognized by us for 2006. See Note 10 to our Consolidated Financial Statements for a discussion of the assumptions made in determining these amounts.

(2) Mr. Capobianco assigns to Vulcan Capital any compensation attributable to his service as director. Mr. Petersen assigns to EnCap Energy Capital Fund III, L.P. any compensation attributable to his service as director.

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. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. In addition to the annual retainer, each committee chairman (other than the chairman of 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, in each case, in addition to the annual retainer.

Our non-employee directors receive LTIP awards or cash equivalent awards as part of their compensation. The LTIP awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The three non-employee directors who serve on our audit committee each received a grant of 10,000 units (vesting 2,500 units per year). Mr. Sinnott received a grant of 5,000 units (vesting 1,250 per year). Mr. Petersen and Mr. Capobianco each have assigned all director compensation to an affiliate of the GP LLC member that appointed him as a director. Such affiliates receive an annual cash payment equivalent in value to the annual vesting of Mr. Sinnott s award.

All LTIP awards held by a director will vest in full upon the next vesting date after the death or disability (as determined in good faith by the board) of the director. For any independent directors (as defined in the GP LLC Agreement, and currently including Messrs. Goyanes, Smith and Symonds), the awards will also vest in 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 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 Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholder 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 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, directors, the Named Executive Officers, and all directors and executive officers as a group as of February 20, 2007.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)
Paul G. Allen	14,386,074(2)	13.1%
Vulcan Energy Corporation	12,390,120(3)	11.3%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	9,238,534(4)	8.4%
Greg L. Armstrong	253,412(5)(6)(7)	(8)
Harry N. Pefanis	146,567(6)(7)	(8)
Phillip D. Kramer	98,370(6)(7)	(8)
George R. Coiner	58,126(6)(7)	(8)
John P. vonBerg	(6)	(8)
David N. Capobianco	(9)	(8)
Everardo Goyanes	11,200	(8)
Gary R. Petersen	5,200(10)	(8)
Robert V. Sinnott	16,250(11)	(8)
Arthur L. Smith	13,350	(8)
J. Taft Symonds	22,500	(8)
All directors and executive officers as a group (15 persons)	811,120(7)(12)	(8)

(1) Limited partner units constitute 98% of our equity, with the remaining 2% held by our general partner. The beneficial ownership of our general partner is set forth in the table below under 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 14% 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 80.1% of the outstanding shares of common stock of Vulcan Energy Corporation. Mr. Allen also controls Vulcan Capital Private Equity I LLC (Vulcan LLC), which is the record holder of 1,995,954 common units. The address for Mr. Allen 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 Corporation or any of its affiliates.

(3) The address for Vulcan Energy Corporation is c/o Plains All American GP LLC, 333 Clay Street, Suite 1600, Houston, Texas 77002.

(4) Richard A. Kayne is 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 9,238,534 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 270,365 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 approximately 173,444 common units owned by our general partner in connection with its 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, and Director Independence General Partner s Performance Option Plan.

(6) Does not include unvested phantom units granted under the 2005 LTIP, none of which will vest within 60 days of the date hereof. See Outstanding Equity Awards at Fiscal Year-End.

(7) Includes the following vested, unexercised options to purchase common units under the general partner s Performance Option Plan. Mr. Armstrong: 37,500; Mr. Pefanis: 27,500; Mr. Kramer: 22,500; Mr. Coiner: 21,250; and all directors and executive officers as a group: 126,250.

(8) Less than one percent.

(9) The GP 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 as one of our directors by Vulcan Energy Corporation, of which he is Chairman of the Board. Mr. Capobianco owns an equity interest in Vulcan LLC and has the right to receive a performance-based fee based on the performance of the holdings of Vulcan LLC and Vulcan Energy Corporation. Mr. Capobianco disclaims any deemed beneficial ownership of our common units held by Vulcan Energy Corporation and Vulcan LLC or any of their affiliates beyond his pecuniary interest therein, if any. By virtue of its 54% ownership in the general partner, Vulcan Energy Corporation has the right at any time to cause the election of an additional director to the Board.

(10) Pursuant to the GP LLC Agreement, Mr. Petersen has been designated one of our directors by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is Senior Managing Director. Mr. Petersen disclaims any deemed beneficial ownership of the 618,896 common units held by E-Holdings III, L.P. and E-Holdings V, L.P. or other affiliates of EnCap Investments L.P. beyond his pecuniary interest. The address for E-Holdings III, L.P. and E-Holdings V, L.P. is 1100 Louisiana, Suite 3150, Houston, Texas 77002.

(11) Pursuant to the GP 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 President. Mr. Sinnott disclaims any deemed beneficial ownership of any common 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.

(12) As of February 23, 2007, no units were pledged by directors or Named Executive Officers. Certain of the directors and Named Executive Officers hold units in a marginable broker s account, but none of the units were margined as of February 23, 2007.

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, WA 98104	54.3%
Vulcan Energy Corporation(2) c/o Plains All American GP LLC 333 Clay Street, Suite 1600 Houston, TX 77002	54.3%
KAFU Holdings, L.P.(3) 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	20.3%
E-Holdings III, L.P.(4) 1100 Louisiana, Suite 3150 Houston, TX 77002	9.0%
E-Holdings V, L.P.(4) 1100 Louisiana, Suite 3150 Houston, TX 77002	2.1%
PAA Management, L.P.(5) 333 Clay Street, Suite 1600 Houston, TX 77002	4.9%
Wachovia Investors, Inc. 301 South College Street, 12th Floor Charlotte, NC 28288	4.2%
Mark E. Strome 100 Wilshire Blvd., Suite 1500 Santa Monica, CA 90401	2.6%
Strome MLP Fund, L.P. 100 Wilshire Blvd., Suite 1500 Santa Monica, CA 90401	1.3%
Lynx Holdings I, LLC 15209 Westheimer, Suite 110 Houston, TX 77082	1.2%

(1) Mr. Allen owns approximately 80.1% of the outstanding shares of common stock of Vulcan Energy Corporation. Vulcan Energy GP Holdings Inc., a subsidiary of Vulcan Energy Corporation, owns 54.3% of the equity of our general partner. Vulcan Energy Corporation has pledged all of its equity interest in Vulcan Energy GP Holdings Inc. as security for its obligations under the Second Amended and Restated Credit Agreement

dated as of August 12, 2005 among Vulcan Energy Corporation, Bank of America, N.A. and the lenders party thereto (the VEC Credit Agreement). A default by Vulcan Energy Corporation under the VEC Credit Agreement could result in an indirect change in control 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 and its affiliates beyond his pecuniary interest therein, if any.

(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. and E-Holdings V, L.P. beyond his pecuniary interest.

(5) PAA Management, L.P. is owned entirely by certain members of senior management, including Messrs. Armstrong (approximately 25%), Pefanis (approximately 14%), Kramer (approximately 9%), Coiner (approximately 9%) and vonBerg (approximately 4%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Directors and executive officers as a group own approximately 76% 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

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2006. For a description of these plans, see Item 13. Certain Relationships and Related Transactions, and Director Independence Equity-Based Long-Term Incentive Plans.

Plan Category	**Number of Units to be Issued upon Exercise/Vesting of Outstanding Options, Warrants and Rights (a)**	**Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)**	**Number of Units Remaining Available for Future Issuance under Equity Compensation Plans (c)**
Equity compensation plans approved by unitholders:			
1998 Long Term Incentive Plan	40,550(1)	N/A(2)	506,708(1)(3)
2005 Long Term Incentive Plan	2,195,700(4)	N/A(2)	804,300(3)
Equity compensation plans not approved by unitholders:			
1998 Long Term Incentive Plan	(1)(5)	N/A(2)	(6)
General Partner s Performance Option Plan	(7)	$ 11.55(8)	(7)
PPX Successor LTIP		N/A	999,809(9)

(1) As originally instituted by our former general partner prior to our initial public offering, the 1998 LTIP contemplated the 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,

2006, we have issued approximately 427,742 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 have vested were satisfied without the issuance of units. These phantom units were settled in cash or withheld for taxes. Any units not issued upon vesting will become available for future issuance under column (c).

(2) Phantom unit awards under the 1998 LTIP and 2005 LTIP vest without payment by recipients.

(3) In accordance with Item 201(d) of Regulation S-K, column (c) excludes the securities disclosed in column (a). However, as discussed in footnotes (1) and (4), any phantom units represented in column (a) that are not satisfied by the issuance of units become available for future issuance.

(4) The 2005 Long Term Incentive Plan was approved by our unitholders in January 2005. The 2005 LTIP contemplates the issuance or delivery of up to 3,000,000 units to satisfy awards under the plan. The number of units presented in column (a) assumes that all outstanding grants will be satisfied by the issuance of new units upon vesting. In fact, some portion of the phantom units may be settled in cash and some portion will be withheld for taxes. Any units not issued upon vesting will become available for future issuance under column (c).

(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 387,032 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 a Performance Option Plan for officers and key employees pursuant to which optionees have the right to purchase units from the general partner. The 450,000 units that were originally authorized to 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 without economic cost to the Partnership. Thus, there will be no units issued upon exercise/vesting of outstanding options. Options for approximately 161,500 units are currently outstanding. All are vested, and no units remain available for future grant. See Item 13. Certain Relationships and Related Transactions, and Director Independence General Partner s Performance Option Plan.

(8) As of December 31, 2006, the strike price for all outstanding options under the general partner s Performance Option Plan was approximately $11.55 per unit. The strike price decreases as distributions are paid. See Item 13. Certain Relationships and Related Transactions, and Director Independence General Partner s Performance Option Plan.

(9) In connection with the Pacific merger, under applicable stock exchange rules, we carried over the available units under the Pacific LTIP (applying the conversion ratio of 0.77 PAA units for each Pacific unit). In that regard, we have adopted the Plains All American PPX Successor Long-Term Incentive Plan (the PPX Successor LTIP). Potential awards under such plan include options and phantom units (with or without tandem DERs). The provisions of such plan are substantially the same as the 2005 LTIP, except that awards under the PPX Successor LTIP may only be made to employees who were working for Pacific at the time of the merger or to employees hired after the date of the Pacific acquisition.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

For a discussion of director independence, see Item 10 Directors and Executive Officers of Our General Partner and Corporate Governance.

Our General Partner

Our operations and activities are managed, 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. Total costs reimbursed by us to our general partner for the year ended December 31, 2006 were approximately $204.6 million.

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. In connection with the Pacific merger, our general partner agreed to a temporary reduction in the amount of incentive distribution right otherwise payable to it. The aggregate reduction will be $65 million over a five-year period, with a reduction of $20 million, $15 million, $15 million, $10 million and $5 million in years one through five, respectively. The first reduction was made in connection with the distribution paid on February 14, 2007.

The following table illustrates the allocation of aggregate distributions at different per-unit levels, excluding the effect of the incentive distribution reductions:

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	$ 198,000	$ 4,041	$ 202,041	2.0%
$1.98	$ 217,800	$ 7,535	$ 225,335	3.3%
$2.70	$ 297,000	$ 33,935	$ 330,935	10.3%
$3.20	$ 352,000	$ 88,935	$ 440,935	20.2%
$3.50	$ 385,000	$ 121,935	$ 506,935	24.1%
$3.75	$ 412,500	$ 149,435	$ 561,935	26.6%
$4.00	$ 440,000	$ 176,935	$ 616,935	28.7%

(1) In thousands.

(2) Assumes 110,000,000 units outstanding. Actual number of units outstanding as of December 31, 2006 was 109,405,178. 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.

Equity-Based Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the 1998 LTIP) and the Plains All American GP LLC 2005 Long-Term Incentive Plan (the 2005 LTIP and, together with the 1998 LTIP, the Plans) for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the Plans include phantom units (referred to as restricted units in the 1998 LTIP), distribution equivalent rights (DERs) and unit options. As amended, the 1998 LTIP authorizes the grant of awards covering an aggregate of 1,425,000 common units deliverable upon vesting or exercise (as applicable) of such awards. The 2005 LTIP authorizes the grant of awards covering an aggregate of 3,000,000 common units deliverable upon vesting or exercise (as applicable) of such awards. Our general partner s board of directors has the right to alter or amend the Plans 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).

As of December 31, 2006, giving effect to vested grants, grants of approximately 40,550 and 2,195,700 unvested phantom units remain outstanding under the 1998 LTIP and 2005 LTIP, respectively, and approximately 893,740 and 804,300 remain available for future grant, respectively. In addition, the PPX Successor LTIP has available 999,809 units that were adopted from the Pacific LTIP. These units can be used only in awards to former Pacific employees or employees hired after the date of the Pacific acquisition. The compensation committee or board of directors may, in the future, make additional grants under the Plans to employees and directors containing such terms as the compensation committee or board of directors shall determine, including DERs with respect to phantom units. DERs entitle 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.

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.

Unit Options. Although the Plans currently permit the grant of options covering common units, no options have been granted under the Plans to date. However, the compensation committee or board of directors may, in the future, make grants under the plan to employees and directors containing such terms as the compensation committee or board of directors shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

General Partner s Performance Option Plan

In 2001, certain owners of the general partner 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. As of December 31, 2006, 171,000 options remain outstanding under the plan, all of which are fully vested. No units remain available for future grant. The original exercise price of the options was $22 per unit, declining over time by an amount equal to 80% of each quarterly distribution per unit. As of December 31, 2006, the exercise price was approximately $11.55 per unit. Because the units underlying the plan were contributed to the general partner, we have no obligation to reimburse the general partner for the cost of the units upon exercise of the options.

Transactions with Related Persons

Vulcan Energy

As of December 31, 2006, Vulcan Energy and its affiliates owned approximately 54% of our general partner interest, as well as approximately 11.3% of our outstanding limited partner units.

Voting Agreement

In August 2005, one of the owners of our general partner notified the remaining owners of its intent to sell its 19% interest in the general partner. The remaining owners elected to exercise their right of first refusal, such that the 19% interest was purchased pro rata by all remaining owners. As a result of the transaction, the interest of Vulcan Energy increased from 44% to approximately 54%. At the closing of the transaction, Vulcan Energy entered into a voting agreement that restricts its ability to unilaterally elect or remove our independent directors, and separately, our CEO and COO agreed, subject to certain ongoing conditions, to waive certain change-of-control payment rights that would otherwise have been triggered by the increase in Vulcan Energy s ownership interest. These ownership changes to our general partner had no material impact on us.

Administrative Services Agreement

On October 14, 2005, GP LLC and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the Services Agreement). Pursuant to the Services Agreement, GP LLC provides administrative services to Vulcan Energy for consideration of an annual fee, plus certain expenses. Effective October 1, 2006, the annual fee for providing these services was increased to $1.0 million. The Services Agreement extends through October 2008, at which time it will automatically renew for successive one-year periods unless either party provides written notice of its intention to terminate the Services Agreement. Pursuant to the agreement, Vulcan Energy has appointed certain employees of GP LLC as officers of Vulcan Energy for administrative efficiency. Under the

Services Agreement, Vulcan Energy acknowledges that conflicts may arise between itself and GP LLC. If GP LLC believes that a specific service is in conflict with the best interest of GP LLC or its affiliates then GP LLC is entitled to suspend the provision of that service and such a suspension will not constitute a breach of the Services Agreement. Vulcan Gas Storage LLC (discussed below) operates separately from Vulcan Energy, and services we provide to Vulcan Gas Storage LLC are not covered under the Services Agreement.

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Predecessor Agreements

In 2001, Plains Resources, Inc. transferred a portion of its indirect interest in our general partner to certain of the current owners. As successor in interest to Plains Resources, Vulcan Energy is party to certain agreements related to such transfer, including the following:

- a separation agreement entered into in 2001 in connection with the transfer of interests in our general partner pursuant to which (i) Vulcan indemnifies 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 indemnify Vulcan for claims related to the midstream business, whenever arising. Vulcan also indemnifies, 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 of interest, including certain non-compete obligations.

Crude Oil Purchases

Until August 12, 2005, Vulcan Energy owned 100% of Calumet Florida L.L.C. Calumet is now owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. We purchase crude oil from Calumet. We paid approximately $45.1 million to Calumet in 2006. Calumet may request from time to time that we provide fixed pricing or a range of pricing for a portion of its production. When we offer such an arrangement, we protect our position by placing hedges on equivalent amounts, and charge Calumet a fee of $0.20 per barrel. No such arrangements were in place during 2006.

Other

In addition to those relationships described above, we have engaged in other transactions with affiliates of Vulcan Energy. See Equity Offerings and Investment in Natural Gas Storage Joint Venture.

Equity Offerings

In December 2006, we sold 6,163,960 common units, approximately 10% and 10% of which were sold to investment funds affiliated with KACALP and Encap Investments, L.P., respectively. In July and August 2006, we sold a total of 3,720,930 common units, approximately 12.5% and 18.7% of which were sold to investment funds affiliated with KACALP and Vulcan Capital, respectively. In addition, in March and April 2006, we sold 3,504,672 common units, approximately 20% of which were sold to investment funds affiliated with KACALP. KAFU Holdings, L.P., which owns 20.3% of our general partner and has a representative on our board of directors, is managed by KACALP. Vulcan Capital, the investment arm of Paul G. Allen, and its subsidiaries own approximately 54% of our general partner interest and has a representative on our board of directors. Affiliates of EnCap own approximately 11.1% of our general partner and have a representative on our board of directors.

In September 2005, we sold 4,500,000 units in a public offering at a unit price to the public of $42.20. We received net proceeds of approximately $182.3 million, or $40.512 per unit after underwriters discounts and commissions. Concurrently with the public offering, we sold 679,000 common units pursuant to our existing shelf registration statement to investment funds affiliated with KACALP in a privately negotiated transaction for a purchase price of $40.512 per unit (equivalent to the public offering price less underwriting discounts and commissions). On February 25, 2005, we issued 575,000 common units in a private placement to a subsidiary of Vulcan Capital. The sale price was $38.13 per unit, which represented a 2.8% discount to the closing price of the units on February 24, 2005.

Tank Car Lease and CANPET

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. 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. 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. Duckett. Mr. Duckett owns a 23.4% interest in Pivotal.

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 consisting 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 Item 12. 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 on 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 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.

Investment in Natural Gas Storage Joint Venture

PAA/Vulcan, a limited liability company, was formed in the third quarter of 2005. We own 50% of PAA/Vulcan and the remaining 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan Capital, the investment arm of Paul G. Allen. The Board of Directors of PAA/Vulcan consists of an equal number of our representatives and representatives of Vulcan Gas Storage, and is responsible for providing strategic direction and policy-making. We, as the managing member, are responsible for the day-to-day operations.

In September 2005, PAA/Vulcan acquired ECI, an indirect subsidiary of Sempra Energy, for approximately $250 million. ECI develops and operates underground natural gas storage facilities. We and Vulcan Gas Storage LLC each made an initial cash investment of approximately $112.5 million, and Bluewater Natural Gas Holdings, LLC a subsidiary of PAA/Vulcan (Bluewater) entered into a $90 million credit facility contemporaneously with closing. Approximately $25.4 million was outstanding under this credit facility as of February 20, 2007. We currently have no direct or contingent obligations under the Bluewater credit facility.

PAA/Vulcan is developing a natural gas storage facility through its wholly owned subsidiary, Pine Prairie Energy Center, LLC (Pine Prairie). Proper functioning of the Pine Prairie storage caverns will require a minimum operating inventory contained in the caverns at all times (referred to as base gas). During the first quarter of 2006, we arranged to provide the base gas for the storage facility to Pine Prairie at a price not to exceed $8.50 per million cubic feet. In conjunction with this arrangement, we executed hedges on the NYMEX for the relevant delivery periods of 2007, 2008 and 2009. We received a fee of approximately $1 million for our services to own and manage the hedge positions and to deliver the natural gas.

We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund equity requests associated with certain projects specified in the joint venture agreement. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for up to 50% of such equity requests. In some cases, Vulcan Gas Storage s obligation is subject to a maximum amount, beyond which Vulcan Gas Storage s participation is optional. For any other capital expenditures, or capital expenditures with respect to which Vulcan Gas Storage s participation is optional, if Vulcan Gas Storage elects not to participate, we have the right to make additional capital contributions to fund 100% of the project until our interest in PAA/Vulcan equals 70%. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage s interest. Once PAA s ownership interest is 70% or more, Vulcan Gas Storage would have the right, but not the obligation, to make future capital contributions proportionate to its ownership interest at the time.

In conjunction with formation of PAA/Vulcan and the acquisition of ECI, PAA and Paul G. Allen provided performance and financial guarantees to the seller with respect to PAA/Vulcan s performance under the purchase agreement, as well as in support of continuing guarantees of the seller with respect to ECI s obligations under certain gas storage and other contracts. PAA and Paul G. Allen would be required to perform under these guarantees only if ECI was unable to perform. In addition, we provided a guarantee under one contract with an indefinite life for which neither Vulcan Capital nor Paul G. Allen provided a guarantee. In exchange for the disproportionate guarantee, PAA will receive preference distributions totaling $1.0 million over ten years from PAA/Vulcan (distributions that would otherwise have been paid to Vulcan Gas Storage LLC). We believe that the fair value of the obligation to stand ready to perform is minimal. In addition, we believe the probability that we would be required to perform under the guaranty is extremely remote; however, there is no dollar limitation on potential future payments that fall under this obligation.

PAA/Vulcan will reimburse us for the allocated costs of PAA s non-officer staff associated with the management and day-to-day operations of PAA/Vulcan and all out-of-pocket costs. In addition, in the first fiscal year that EBITDA (as defined in the PAA/Vulcan LLC agreement) of PAA/Vulcan exceeds $75.0 million, we will receive a distribution from PAA/Vulcan equal to $6.0 million per year for each year since formation of the joint venture, subject to a maximum of 5 years or $30 million. Thereafter, we will receive annually a distribution equal to the greater of $2 million per year or two percent of the EBITDA of PAA/Vulcan.

Other

Thomas Coiner, an employee in our marketing department, is the son of George R. Coiner, Senior Group Vice President. In 2006, Thomas Coiner received compensation in excess of $120,000.

Review, Approval or Ratification of Transactions with Related Persons

Pursuant to our Governance Guidelines, a director is expected to bring to the attention of the CEO or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and the Partnership or GP LLC on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between the Partnership and GP LLC, the resolution of any such conflict or potential conflict should be addressed by the board in accordance with the provisions of the Partnership Agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under the Partnership Agreement. Such resolution may include resolution of any derivative conflicts created by an executive officer s ownership of interests in GP LLC or a director s appointment by an owner of GP LLC.

Pursuant to our Code of Business Conduct, any Executive Officer must avoid conflicts of interest unless approved by the board of directors.

In the case of any sale of equity in which an owner or affiliate of an owner of our general partner participates, our practice is to obtain general approval of the full board for the transaction. The board typically delegates authority to set the specific terms to a pricing committee, consisting of the CEO and one independent director. Actions by the pricing committee require unanimous approval.

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 millions)

	Year Ended December 31, 2006	Year Ended December 31, 2005
Audit fees(1)	$ 2.4	$ 2.2
Audit-related fees(2)	0.3	0.1
Tax fees(3)	1.6	0.5
All other fees(4)	0.9	0.3
Total	$ 5.2	$ 3.1

(1) Audit fees 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.

(2) Audit-related fees primarily relate to audits of our benefit plans and carve-out audits of acquired companies.

(3) Tax fees are related to tax processing as well as the preparation of Forms K-1 for our unitholders and includes incremental activity assumed with the issuance of Forms K-1 for former Pacific unitholders.

(4) All other fees primarily consist of those associated with due diligence performed on our behalf and evaluating potential acquisitions.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) (1) Financial Statements

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

(2) Financial Statement Schedules

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

(3) Exhibits

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	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 quarter ended March 31, 2004).
3.4	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 quarter ended March 31, 2004).
3.5	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to the Registration Statement on Form S-3 filed August 27, 2001).

3.6	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001).
3.7	Second Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated September 12, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 16, 2005).
3.8	Second Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated September 12, 2005 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed September 16, 2005).
3.9	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.10	Certificate of Incorporation of Pacific Energy Finance Corporation.
3.11	Bylaws of Pacific Energy Finance Corporation.
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 the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	Third Supplemental Indenture (Series A and Series B 4.75% 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 Bank, 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 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.6	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 4.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.7	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 4.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.8	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.9	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated as of May 12, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline,

L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).

4.10	Seventh Supplemental Indenture, dated as of May 12, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains LPG Services GP LLC, Plains LPG Services, L.P. and Lone Star Trucking, LLC and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.11	Eighth Supplemental Indenture, dated as of August 25, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing International GP LLC, Plains Marketing International, L.P. and Plains LPG Marketing, L.P. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.12	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017), dated as of October 30, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.13	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037), dated as of October 30, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.14	Eleventh Supplemental Indenture dated November 15, 2006 to Indenture dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Pacific Energy Finance Corporation, Rangeland Marketing Company and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.15	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 71/8% senior notes due 2014 (incorporated by reference to Exhibit 4.21 to Pacific s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
4.16	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 71/8% senior notes due 2014 (incorporated by reference to Exhibit 4.1 to Pacific s Current Report on Form 8-K filed March 9, 2005).
4.17	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 71/8% senior notes due 2014.
4.18	Third Supplemental Indenture dated November 15, 2006 to Indenture dated as of June 16, 2004, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Rangeland Marketing Company, Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, Plains Marketing Canada, L.P., PMC (Nova Scotia) Company, Basin Holdings GP LLC, Basin Pipeline Holdings, L.P., Rancho Holdings GP LLC, Rancho Pipeline Holdings, L.P.,

Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC, Plains Marketing International GP LLC, Plains Marketing International L.P., Plains LPG Marketing, L.P., PAA Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed November 21, 2006).

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