PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 29, 2008

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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, 2007

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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer þ   Accelerated Filer o   Non-Accelerated Filer o   Smaller Reporting Company o
(Do not check if a smaller reporting company)

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

The aggregate market 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 $6.4 billion on June 29, 2007, based on $63.65 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 20, 2008, there were outstanding 115,981,676 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K 2007 ANNUAL REPORT

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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:

- failure to implement or capitalize on planned internal growth projects;
- 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;
- shortages or cost increases of power supplies, materials or labor;
- 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 transportation 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;
- successful integration and 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;

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.

PART I

Items 1 and 2. *Business and Properties*

General

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 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 subsidiaries, unless 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 are also involved in the development and operation of natural gas storage facilities.

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing.

Transportation Segment

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

As of December 31, 2007, 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 crude oil and refined products pipelines and gathering systems;
- 23 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 83 trucks and 364 trailers; and
- 62 transport and storage barges and 32 transport tugs through our interest in Settoon Towing, LLC (Settoon Towing).

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

Facilities Segment

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.

As of December 31, 2007, we owned and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 47 million barrels of crude oil and refined products capacity primarily at our terminalling and storage locations;
- approximately 6 million barrels of LPG capacity; 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 24,000 barrels per day.

At year-end 2007, we were in the process of constructing approximately 10 million barrels of additional above-ground crude oil and refined product terminalling and storage facilities and approximately 1 million barrels of underground LPG storage capacity, the majority of which we expect to place in service during 2008.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2007, PAA/Vulcan owned and operated approximately 26 billion cubic feet of underground storage capacity and was constructing an additional 24 billion cubic feet of underground natural gas storage capacity, which is expected to be placed in service in stages over the next several years.

Marketing Segment

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 and the seasonal storage of LPG;

- 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

- 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.

We believe our marketing activities are counter-cyclically balanced to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside potential associated with opportunities inherent in volatile market conditions. This is achieved by utilizing storage facilities at major interchange and terminalling locations and various hedging strategies. See Crude Oil Volatility; Counter-Cyclical Balance; Risk Management.

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 outright commodity price changes.

In addition to substantial working inventories and working capital associated with its merchant activities, as of December 31, 2007, our marketing segment also owned crude oil and LPG classified as long-term assets and a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

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

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

- 540 trucks and 710 trailers; and

- 1,400 railcars.

In connection with its operations, the marketing segment secures transportation and facilities services from our 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 or at the same rates as those charged to third-party shippers. 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.

Although certain activities in our marketing segment are affected by seasonal aspects, in general, seasonality does not have a material impact on our operations and segments.

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. Toward this end, we endeavor to address regional supply and demand imbalances for crude oil, refined products and LPG in the United States and Canada by combining the strategic location and 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 products 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 optimize our presence in the waterborne importation of foreign crude oil;
- expanding our presence in the refined products supply and marketing sector;
- selectively pursuing strategic and accretive acquisitions of crude oil, refined products and LPG transportation, terminalling, storage and marketing assets and businesses that complement our existing asset base and distribution capabilities; and
- using our terminalling and storage assets in conjunction with our marketing activities to capitalize on inefficient energy markets and 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. PAA/Vulcan s 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-adjusted EBITDA multiple of approximately 3.5x (adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity compensation 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)); and

an average adjusted 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, refined products and LPG. The crude oil, refined products and LPG purchased in these transactions are hedged. 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. We also incur short-term debt for New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin requirements.

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 from capital expansion projects to adjusted EBITDA. At December 31, 2007, our long-term debt-to-total capitalization ratio was approximately 43% and our adjusted EBITDA-to-interest coverage multiple on a trailing twelve month basis was above our targeted metric. Based on our December 31, 2007 long-term debt balance and the midpoint of our guidance for 2008 furnished in a Form 8-K dated February 13, 2008, our long-term debt-to-adjusted-EBITDA multiple would be approximately 3.3 times.

Credit Rating

As of February 2008, our senior unsecured ratings with Standard & Poor s and Moody s Investment Services were BBB-, stable outlook, and Baa3, stable outlook, respectively, both of which are considered investment grade ratings. We have targeted the attainment of stronger investment grade ratings of mid to high-BBB and Baa categories for Standard & Poor s and Moody s Investment Services, respectively. However, our current ratings might not remain in effect for any given period of time, we might not be able to attain the higher ratings we have targeted and one or both of these ratings might 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 to successfully execute our principal business strategy:

Many of our transportation segment and facilities segment assets are strategically located and operationally flexible. 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 crude oil marketing activities are counter-cyclically balanced. We believe the variety 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 ten years, we have completed and integrated approximately 50 acquisitions with an aggregate purchase price of approximately $5.3 billion. We have also implemented internal expansion capital projects totaling over $1.3 billion. In addition, we believe we have significant resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2007, we had approximately $1.0 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 large capitalization midstream master limited partnerships.

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, and an average of more than 15 years with us or our predecessors and affiliates. In addition, through their ownership of

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common units, indirect interests in our general partner, grants of phantom units and the Class B units in Plains AAP, L.P., our management team has a vested interest in our continued success.

We believe these competitive strengths will aid 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 to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is 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. References to our general partner, as the context requires, include any or all of PAA GP LLC, 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. Plains All American GP LLC 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.

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The chart below 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 22% of all outstanding units.

(2) Incentive Distribution Rights (IDRs). See Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities for discussion of our general partner s incentive distribution rights.

(3) The Partnership holds 100% direct and indirect ownership interests in consolidated operating subsidiaries including, but not limited to, Plains Pipeline, L.P., Plains Marketing, L.P., Plains LPG Services, L.P., Pacific Energy Partners LLC, PMC (Nova Scotia) Company and Plains Marketing Canada, L.P.

(4) The Partnership holds direct and indirect equity interests in unconsolidated entities including, but not limited to, PAA/Vulcan Gas Storage, LLC and Settoon Towing LLC.

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, LPG assets and natural gas storage 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, 2007, we have completed approximately 50 acquisitions for a cumulative purchase price of approximately $5.3 billion.

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

Acquisition	Date	Description	Approximate Purchase Price
Tirzah Storage Facility	Oct-2007	Liquefied Petroleum Gas storage facility	$54
Bumstead Storage Facility	Jul-2007	Liquefied Petroleum Gas storage facility	$52
Pacific Energy Partners LP (Pacific)	Nov-2006	Merger of Pacific Energy Partners with and into the Partnership	$2,456
El Paso to Albuquerque Products Pipeline Systems	Sep-2006	Three refined products pipeline systems	$66
CAM/BOA/HIPS Crude oil systems	Jul-2006	64.35% interest in the Clovelly-to-Meraux (CAM) Pipeline system; 100% interest in the Bay Marchand-to-Ostrica-toAlliance (BOA) system and various interests in the High Island Pipeline System (HIPS)(1)	$130
Andrews Petroleum and Lone Star Trucking	Apr-2006	Isomerization, fractionation, marketing and transportation services	$220
South Louisiana Gathering and Transportation Assets (SemCrude)	Apr-2006	Crude oil gathering and transportation assets, including inventory and related contracts in South Louisiana	$129
Investment in Natural Gas Storage Facilities	Sep-2005	Joint venture with Vulcan Gas Storage LLC to develop and operate natural gas storage facilities	$125(2)
Link Energy LLC	Apr-2004	North American crude oil and pipeline operations of Link Energy, LLC (Link)	$332
Capline and Capwood Pipeline Systems	Mar-2004	An approximate 22% undivided joint interest in the Capline Pipeline System and an approximately 76% undivided joint interest in the Capwood Pipeline System	$159

(1) Our interest in HIPS was relinquished in November 2006.

(2) 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.

2007 Acquisitions

During 2007, we completed four acquisitions for aggregate consideration of approximately $123 million. These acquisitions included (i) a commercial refined products supply and marketing business (reflected in our marketing segment) for approximately $8 million in cash, (ii) a trucking business (reflected in our transportation segment) for approximately $9 million in cash, (iii) the Bumstead LPG storage facility located near Phoenix, Arizona (reflected in our facilities segment) for approximately $52 million in cash and (iv) the Tirzah LPG storage facility and other assets located near York County, South Carolina (reflected in our facilities segment) for approximately $54 million in cash. The goodwill associated with these acquisitions was approximately $12 million.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil, refined products and LPG related assets and, through our interest in PAA/Vulcan, natural gas storage assets. In addition, we have in the past evaluated and pursued, 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. Even after we have reached agreement on a purchase price with a potential seller, confirmatory due diligence or negotiations regarding other terms of the acquisition can cause discussions to be terminated. Accordingly, we typically do not announce a transaction until after we have executed a definitive acquisition agreement. Although we expect the acquisitions we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. See Item 1A. Risk Factors Risks Related to Our Business If we do not make acquisitions on economically acceptable terms, our future growth may be limited and Our acquisition strategy involves risks that may adversely affect our business.

Global Petroleum Market Overview

World oil consumption continues to increase and is forecast to increase approximately 35% by 2030. China, the Middle East, the United States and India are expected to account for most of the increase in oil consumption. The United States is the world s most liquid market for crude oil. The United States comprises less than 5% of the world s population and generates only 10% of the world s petroleum production, but consumes approximately 24% of the world s petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil, natural gas liquids and other liquid petroleum products) and is derived from the most recent information published by the Energy Information Administration (EIA) (see EIA website at www.eia.doe.gov).

			Projected	
	2007	**2008**	**2015**	**2030**
	(Millions of barrels per day)			
Supply				
U.S	8.6	8.6	10.3	10.4
Canada	3.4	3.6	4.3	5.3
Other	9.4	9.4	8.5	7.5
Organization for Economic Co-operation and Development (OECD)	21.4	21.6	23.1	23.2
Organization of the Petroleum Exporting Countries (OPEC)-12	34.8	36.2	35.9	45.0
Former Soviet Union	12.7	13.1	15.2	18.1
China	3.9	3.9	3.2	3.2
Other	11.8	12.3	20.2	27.8

Non-OECD	63.2	65.5	74.5	94.1
Total World Production	84.6	87.1	97.6	117.3

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			Projected	
	2007	2008	2015	2030
	(Millions of barrels per day)			
Demand				
U.S	20.7	21.0	22.8	26.8
Canada	2.3	2.2	2.5	2.6
Europe	15.4	15.4	15.9	16.3
Japan	5.2	5.2	5.5	5.5
Other	5.8	5.8	7.0	8.5
OECD	49.4	49.6	53.7	59.7
Other Asia	8.7	8.8	7.7	10.3
Former Soviet Union	4.4	4.5	6.0	7.1
China	7.7	8.2	10.0	15.1
Other	15.6	16.1	20.3	25.1
Non-OECD	36.4	37.6	44.0	57.6
Total World Consumption	85.8	87.2	97.7	117.3
Net World Production/(Consumption)	(1.2)	(0.1)	(0.1)	
U.S. Production as % of World Production	10%	10%	11%	9%
U.S. Consumption as % of World Consumption	24%	24%	23%	23%

World economic growth is a driver of the world petroleum market. To the extent that an event causes weaker world economic growth, energy demand would decline. Weaker energy demand would also result in lower energy consumption, lower energy prices, or both, depending on the production responses of producers. Recent volatility in the financial markets and other geopolitical factors have contributed to uncertainty in the petroleum market and, therefore, have caused significantly high volatility in prices and market structure.

Crude Oil Market Overview

The definition of a commodity is a mass-produced unspecialized product and implies the attribute of fungibility. Crude oil is typically referred to as a commodity, however it is neither unspecialized nor 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, which result in 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.

The lack of fungiblity of the various grades of crude oil creates logistical transportation, terminalling and storage challenges and inefficiencies associated with regional volumetric supply and demand imbalances. These logistical inefficiencies are created as certain qualities of crude oil are indigenous to particular regions or countries. Also, each refinery has a distinct configuration of process units designed to handle particular grades of crude oil. The relative yields and the cost to obtain, transport and process the crude oil drives the refinery s choice of feedstock. 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.

Our assets and our business strategy are designed to serve 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 EIA, during the twelve months ended October 2007, the United States consumed approximately 15.1 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 22 years, increasing from 3.2 million

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barrels per day in 1985 to 10.0 million barrels per day for the 12 months ended October 2007, as U.S. refinery demand has increased and domestic crude oil production has declined due to natural depletion. By 2030, foreign imports of crude oil in the U.S. are expected to increase to approximately 13.1 million barrels per day. The table below shows the overall domestic petroleum consumption projected out to 2030 and is derived from the most recent information published by the EIA (see EIA website at www.eia.doe.gov).

	Actual		Projected	
	2007	2008	2015	2030
	(Millions of barrels per day)			
Domestic Crude Oil Production	5.1	5.1	5.9	5.4
Net Imports Crude Oil	10.0	10.1	10.5	13.1
Crude Oil Input to Domestic Refineries	15.1	15.2	16.4	18.5
Net Product Imports	2.1	2.3	2.0	3.3
Other (NGL Production, Refinery Processing Gain)	3.5	3.5	4.4	5.0
Total Domestic Petroleum Consumption	20.7	21.0	22.8	26.8

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 2007 and is derived from information published by the EIA (see EIA website at www.eia.doe.gov) (in millions of barrels per day).

Petroleum Administration Defense District	Regional Supply	Refinery Demand	Supply Shortfall
PADD I (East Coast)		1.5	(1.5)
PADD II (Midwest)	0.5	3.2	(2.7)
PADD III (South)	2.8	7.4	(4.6)
PADD IV (Rockies)	0.4	0.5	(0.1)
PADD V (West Coast)	1.4	2.5	(1.1)
Total U.S.	5.1	15.1	(10.0)

Although PADD III has the largest absolute volume supply shortfall, we believe PADD II is 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 22 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 470,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1985 to 3.2 million barrels per day for the twelve months ended October 2007. As a result, the volume of crude oil transported into PADD II has increased approximately 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.

Volatility in the crude oil market has increased and we expect it to persist. Some factors that we believe are causing and will continue to cause volatility in the market include:

- The narrowing of the gap between supply and the worldwide growth in demand;
- A reduction in available tankage and U.S. inventory capacity caused by DOT regulations requiring regularly scheduled inspection and repair of tanks remaining in service;
- Regional supply and demand imbalances;
- Political instability in critical producing nations; and
- Significant fluctuations in absolute price as well as grade and location differentials.

The complexity and volatility of the crude oil market creates opportunities to solve the logistical inefficiencies inherent in the business. We believe we are well positioned to capture such opportunities through our:

- strategically located assets;
- specialized crude oil market knowledge;
- extensive relationships with producers and refiners;
- strong capital structure and liquidity position; and
- proven skill sets to acquire and integrate businesses and achieve synergies.

Refined Products Market Overview

Once crude oil is transported to a refinery, it is processed into different petroleum products. These refined products fall into three major categories: fuels such as motor gasoline and distillate fuel oil (diesel fuel and jet fuel); finished non-fuel products such as solvents, lubricating oils and asphalt; 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 and octane enhancers. The performance of the gasoline must meet strictly defined industry standards and environmental regulations that vary based on season and 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 and 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 2007, an increase of approximately 32%. By 2030, the EIA estimates that the U.S. will consume approximately 26.8 million barrels per day of refined products, an increase of approximately 30% 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.

The complexity and volatility of the refined products market creates opportunities to solve the logistical inefficiencies inherent in the business. We are well positioned in certain areas to capture such opportunities. 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 continuing to build 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 2007, an increase of approximately 30%. By 2030, the EIA estimates that the U.S. will consume approximately 2.4 million barrels per day of LPGs, an increase of approximately 14% over recent 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.

The LPG market is driven by seasonal shifts in regional demand including:

- weather;
- seasonal changes in gasoline specifications affecting demand for butane;
- alternating needs of refineries to store and blend LPG;
- complex transportation logistics;
- shortage of diluent for Canadian heavy oil; and
- inefficiency caused by multiple supply sources and numerous regional supply and demand imbalances.

The complexity and volatility of the LPG market creates opportunities to solve the logistical inefficiencies inherent in the business. We are well positioned in certain areas to capture such opportunities. We intend to grow our asset base in the LPG business through expansion projects and future acquisitions. We believe that our asset base provides flexibility in meeting the needs of our customers and opportunities to capitalize on regional supply and demand imbalances in LPG markets. In 2007, we acquired LPG storage facilities in Arizona and South Carolina with 133 million gallons and 52 million gallons of working capacity, respectively. These acquisitions increased our LPG storage capacity by over 33% and complement our activities in the Southeast and along the Eastern seaboard.

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. From 1990 to 2006, domestic natural gas production grew approximately 4% while domestic natural gas consumption rose approximately

13%, resulting in an approximate 133% 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.

A significant portion 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 2008, plans for 39 new LNG terminals in the United States and Bahamas have been proposed, 19 of which are to be situated along the Gulf Coast. Of the 19 proposed Gulf Coast facilities, 17 have been approved by the appropriate regulatory agencies, and 2 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.

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.

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 crude oil and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in Butte and Frontier, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

Following is a tabular presentation of our active pipeline assets in the United States and Canada as of December 31, 2007, grouped by geographic location:

Region / Pipeline and Gathering Systems(1)	System Miles	2007 Average Net Barrels per Day (in thousands)(2)
Southwest US		
Basin	519	378
Other	6,253	449
Southwest US Subtotal	**6,772**	**827**
Western US		
All American	139	47
Line 63/Line 2000	474	175
Other	74	84
Western US Subtotal	**687**	**306**
US Rocky Mountain		
Salt Lake City Core Area Systems	1,004	101
Other	3,296	256
US Rocky Mountain Subtotal	**4,300**	**357**
US Gulf Coast		
Capline(3)	633	235
Other	1,662	518
US Gulf Coast Subtotal	**2,295**	**753**
Central US Subtotal	**3,133**	**165**
Domestic Total	**17,187**	**2,408**
Canada		
Rangeland	1,015	63
Manito	610	73
Other	740	168
Canada Total	**2,365**	**304**
Grand Total	**19,552**	**2,712**
Pipeline and Gathering Systems Under Construction		
Salt Lake City Expansion	95	N/A

(1) Ownership percentage varies on each pipeline and gathering system ranging from approximately 20% to 100%.

(2) Represents average volumes for the entire year of 2007.

(3) Non-operated pipeline.

Southwest US

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 crude oil from the Permian Basin (in west Texas and southern New Mexico) 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 378,000 barrels per day (net to our interest) during 2007.

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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 6 million barrels (5 million barrels, net to our interest) of crude oil storage capacity located along the system. The Basin system is subject to tariff rates regulated by the FERC.

Western US

All American Pipeline System. We own a 100% interest in the 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 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 2007 and 2006, tariffs on the All American Pipeline averaged $2.18 per barrel and $2.07 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 63 and Line 2000, 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. Volumes shipped from the OCS are in decline (as reflected in the table below). See Item 1A. Risk Factors for discussion of the estimated impact of a decline in volumes.

The table below sets forth the historical volumes received from both of these fields for the past five years (barrels in thousands):

	For the Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
Average daily volumes received from:					
Point Arguello (at Gaviota)	8	9	10	10	13
Santa Ynez (at Las Flores)	38	40	41	44	46
Total	46	49	51	54	59

Line 63. We own a 100% interest in the Line 63 system. 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 OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 107-mile trunk pipeline (of which 93 miles is 14-inch pipe and 14 miles is 16-inch pipe), originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The trunk pipeline has a capacity of approximately 110,000 barrels per day. The Line 63 system includes 60 miles of distribution pipelines in the Los Angeles Basin, with a capacity of approximately 144,000 barrels per day, and in the Bakersfield area, 156 miles of gathering pipelines in the San Joaquin Valley, and 22 storage tanks with approximately 1 million barrels of storage capacity and approximately 72,000 barrels per day of throughput capacity. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system. For 2007, combined throughput on all three Line 63 segments totaled an average of approximately 109,000 barrels per day.

Line 2000. We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station (that is part of the All American Pipeline System) and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 151-mile, 20-inch trunk pipeline with a throughput capacity of 130,000 barrels per day. During 2007, throughput on Line 2000 averaged approximately 66,000 barrels per day.

US Rocky Mountain

Salt Lake City Core Area Systems. We own and operate the Salt Lake City Core area systems, which include 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 Area systems consist 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 million barrels of storage capacity as well as 44 miles of extension pipeline (the AREPI System). The trunk pipeline 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. During 2007, throughput on the Salt Lake City Core Area systems averaged approximately 101,000 barrels per day.

US Gulf Coast

Capline Pipeline System. 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 approximately 3 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 approximately 1 million barrels per day of crude oil, approximately 248,000 barrels per day are subject to our interest. During 2007, throughput on our interest averaged approximately 235,000 barrels per day.

Canada

Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system includes the Mid Alberta Pipeline and the Rangeland Pipeline. The Mid Alberta Pipeline is a 141-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. We plan to convert the Mid Alberta Pipeline into a bi-directional pipeline. The Rangeland Pipeline is a proprietary pipeline system that consists of approximately 875 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 80,000 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 56-mile pipeline for high sulfur crude oil, and a 63-mile pipeline for condensate and butane. From Rimbey, third-party pipelines move product north to Edmonton. For 2007, approximately 29,000 barrels per day of crude oil was transported on the segment of the pipeline from Sundre north to Edmonton and approximately 34,000 barrels per day was transported on the pipeline from Sundre south to the United States.

Manito. We own a 100% interest in the Manito heavy oil system. This 610-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. Dulwich is the initiation point of the Manito pipeline which is 381 miles long and terminates in Kerrobert, Saskatchewan at our storage and terminalling facility. The Bodo/Cactus Lake pipeline is 145 miles long and originates in Bodo, Alberta and also terminates at our Kerrobert storage facility. The Kerrobert storage and terminalling facility is connected to the Enbridge pipeline system. For 2007, approximately 73,000 barrels per day of crude oil was transported in the Manito system.

Pipeline and Gathering Systems Under Construction

Salt Lake City Expansion. We are constructing a 95-mile expansion of the Salt Lake City Core system from Wasatch to Salt Lake City, which is scheduled to be completed in the second quarter of 2008. When completed, the volumes from the AREPI System will be transported on the Salt Lake City Expansion and the AREPI System will be shut down. The Salt Lake City Expansion pipeline will have an estimated capacity of 120,000 barrels per day. We have entered into 10-year transportation contracts with four Salt Lake City refiners for service on this pipeline. Also, in November 2007, we signed a master formation agreement through which we will sell a 25% interest in this line to Holly Energy Partners, L.P. As part of this agreement, Holly Refining and Marketing Company 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 $83 million.

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. 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, (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 and (iii) fees from LPG fractionation and isomerization services. Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan.

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Following is a tabular presentation of our active facilities segment assets and those under construction in the United States and Canada as of December 31, 2007, grouped by product type:

Facility	Capacity (in millions of barrels, except where noted)
Crude Oil and Refined Products	
In service:	
Cushing	9
Philadelphia Area	3
Kerrobert	2
LA Basin	10
Martinez and Richmond	5
Mobile and Ten Mile	5
St. James	4
Other	9
Subtotal	**47**
Under construction:	
Cushing	2
Patoka	3
Philadelphia Area	1
St. James	2
Other	2
Pier 400	Under Development
Subtotal	**10**
LPG	
In service:	
Bumstead	2
Tirzah	1
Other	3
Subtotal	**6**
Under construction:	
Bumstead	1
Natural Gas	
In service:	
Bluewater/Kimball(1)	26 Bcf (2)(3)
Under construction:	
Pine Prairie(1)	24 Bcf (2)(3)

(1) Owned through our interest in PAA/Vulcan joint venture.

(2) Our interest in these facilities is 50% of the capacity.

(3) Billion cubic feet (Bcf)

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

Major Facilities Assets

Crude Oil and Refined Products

Cushing Terminal. Our Cushing, Oklahoma Terminal (the 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 enabling deliveries to connecting carriers at their maximum rate. The facility also incorporates numerous environmental and operation safeguards that distinguish it from all other facilities at the Cushing Interchange.

Since 1999, we have completed six separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 11 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks, twenty 270,000-barrel tanks and six 570,000-barrel tanks, all of which are used to store and terminal crude oil. The six 570,000-barrel tanks were placed into service in the fourth quarter of 2007 and the first quarter of 2008, at a cost of approximately $49 million. The expansion is supported by multi-year lease agreements. Our tankage ranges in age from one year to approximately 14 years with an average age of five years. In contrast, we estimate that the average age of the remaining tanks in Cushing owned by third parties is approximately 30 years.

Philadelphia Area Terminals. We own three refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have 40 storage tanks with combined storage capacity of approximately 3 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, and include two dock facilities that can load approximately 10,000 to 12,000 barrels per hour of refined products and black oils (heavy crude oils). The Philadelphia area terminals also receive products from connecting pipelines and offer truck loading services.

At our Philadelphia area terminals, we have completed an ethanol expansion project that enabled us to increase our ethanol handling and blending capabilities as well as our marine receipt capabilities. We plan to expand the facilities by approximately 1 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 the third quarter of 2009 at an estimated cost of $44 million, of which approximately $30 million is scheduled to be spent in 2008.

Kerrobert Terminal. We own a crude oil and condensate storage and terminalling facility, which is located near Kerrobert, Saskatchewan and is connected to our Manito and Cactus Lake pipeline systems. In 2006, we increased the storage capacity at our Kerrobert facility by 600,000 barrels of tankage and an additional 300,000 barrels of tankage was added in 2007, bringing the total storage capacity to approximately 2 million barrels. The cost of these expansions aggregated approximately $42 million. In 2008, we will commence an additional internal growth project on the Kerrobert terminal, which will increase receipt and delivery capacity and reduce third-party costs. The cost of the project is estimated to be approximately $40 million, of which approximately $36 million is estimated to be incurred in 2008.

LA Basin. We own four crude oil and refined product storage facilities in the Los Angeles area with a total of 10 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 35 storage tanks. Approximately 8 million barrels of the storage capacity are in active commercial service, 1 million barrels are used primarily for throughput to other storage tanks and for displacement oil and do not generate revenue independently and the remaining approximately 1 million barrels are out of service. We expect to complete refurbishing the out of service barrels in 2008. We also plan to add approximately 1 million barrels of additional tankage in 2008 at an estimated cost of approximately $20 million, of which approximately $13 million is scheduled to be spent in 2008. 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. 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 terminal at Martinez (which provides refined product and crude oil service) and a terminal at Richmond (which provides refined product service). Our San Francisco area terminals currently have 56 storage tanks with approximately 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.

In 2007, we completed an additional 850,000 barrels of storage capacity at an estimated project cost of approximately $29 million.

Mobile and Ten Mile Terminal. We have a marine terminal in Mobile, Alabama (the Mobile Terminal) that consists of seventeen tanks ranging in size from 10,000 barrels to 225,000 barrels, with current useable capacity of approximately 2 million barrels. Approximately 3 million barrels of additional storage capacity is available at our nearby Ten Mile Facility through a 36-inch pipeline connecting the two facilities.

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 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. Phase I consists of approximately 4 million barrels of capacity and includes seven tanks ranging from 210,000 barrels to 670,000 barrels. The facility also includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. Phase I was completed and placed in service in 2007.

Under the Phase II project, we will construct approximately 2 million barrels of additional tankage at the facility. The Phase II project will expand the total capacity of the facility to approximately 6 million barrels at an estimated project cost of approximately $64 million, of which approximately $8 million is estimated to be incurred in 2008. We estimate that Phase II will be completed in phases in 2008 and 2009.

New Crude Oil Storage Facilities Under Construction and Under Development

Patoka Terminal. In December 2006, we announced plans to build a 3 million barrel crude oil storage and terminal facility at the Patoka Interchange in southern 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 incurred approximately $30 million in 2007 and expect to incur approximately $43 million of the estimated total project cost in 2008. We expect Patoka to be 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 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 refiners in the Los Angeles Basin that provide long-term customer commitments to off-load a total of 200,000 barrels per day of crude oil at the Pier 400 dock. The 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.

Due primarily to regulatory processes and delays, we have failed to meet certain project milestone dates set forth in one of our agreements, and we are likely to miss other project milestones that are approaching under this agreement. However, the counterparty has not given any indication that it will seek to terminate such agreements. We expect that ongoing negotiations with the counterparty to extend the milestone dates will be successful and that the agreements will remain in effect.

In February 2008, we completed an updated cost estimate for the project. We are estimating that Pier 400, when completed, will cost approximately $468 million, which amount includes $32 million of costs associated with emission reduction credits and development and engineering costs incurred to date and $28 million of estimated capitalized interest to be incurred during the construction period. This estimate is subject to change depending on various factors, including the final scope of the project and the requirements imposed through the permitting process. This cost estimate assumes the construction of 4 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. 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 (including the Environmental Impact Review), and ongoing feasibility evaluation. Subject to timely receipt of approvals, we expect construction of the Pier 400 terminal may be partially completed and the facility placed in service in 2010 and to be fully operational in 2011.

LPG Storage Facilities and Terminals

Bumstead. In July 2007, we acquired the Bumstead LPG storage facility for $52 million from AmeriGas Propane. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With 133 million gallons of working capacity (approximately 100 million gallons, or approximately 2 million barrels, of useable capacity), the facility s primary assets include three salt-dome storage caverns, a 24-car rail rack and six truck racks.

In 2008, we will commence an internal growth project on the Bumstead facility, intended to increase capacity by approximately 1 million barrels, add rail car storage capacity and improve the efficiency of the rail rack. The cost of the project is estimated to be approximately $14 million, of which approximately $10 million is estimated to be incurred in 2008.

Tirzah. In October 2007, we acquired the Tirzah LPG storage facility for approximately $54 million from Suburban Propane. The facility has an approximately 1 million barrel underground granite storage cavern and is connected to the Dixie Pipeline System (a third-party system). The facility gives us a greater presence in the Southeast.

We believe these facilities will further support the expansion of our LPG business in North America 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 North America.

Natural Gas Storage Assets (owned through our interest in PAA/Vulcan)

Bluewater/Kimball. The Bluewater gas storage facility, which is located near Detroit, Michigan, is a depleted reservoir with approximately 23 Bcf of capacity and is also strategically positioned. In April 2006, PAA/Vulcan acquired the Kimball gas storage facility and connected this 3 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 2008 and fully operational in 2010, 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, Louisiana LNG terminal, which is the largest LNG import facility in the United States. The initial phase of the facility will consist of three storage caverns with a targeted working capacity of 8 Bcf per cavern and an extensive header system. Drilling operations on all three cavern wells are complete. 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. In January 2008, we applied for a permit to convert the first cavern well from a brine extraction well to a natural gas storage well. The site is located approximately 50 miles from the Henry Hub in Louisiana (the delivery point for NYMEX natural gas futures contracts). Pine Prairie 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 needs 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 and the seasonal storage of LPG;

- 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

- 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.

We believe our marketing activities are counter-cyclically balanced to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside potential associated with opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a 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.

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 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, refined products, LPG sales and waterborne foreign crude imported for the year ended December 31, 2007 (in thousands of barrels):

	Volumes
Crude oil lease gathering	685
Refined products	11
LPG sales	90
Waterborne foreign crude imported	71
Marketing activities total	857

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 trucks 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. Crude oil and LPG is purchased 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, 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 for further discussion of our accounting for exchange and buy/sell agreements.

Credit. Our merchant activities involve the purchase of crude oil, LPG and refined products for resale and require significant extensions of credit by our suppliers. In order to assure our ability to perform our obligations under the 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, LPG and refined products, 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.

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 the date we issue an invoice for the provision of services.

We also have credit risk exposure related to our sales of LPG and refined products; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that these transactions pose a material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as to sell LPG on a current basis to local distributors and retailers. In certain cases our LPG customers prepay for their purchases, in amounts ranging from approximately $2 per barrel to 100% of their contracted amounts. Generally, sales of LPG settle within 30 days of the date of invoice and refined products sales settle within 10 days.

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 $100 per barrel (February 2008) to a low of approximately $10 per barrel (March 1986) over the last 22 years. Segment profit from our transportation activities is dependent on throughput volume, tariff rates and the level of other fees generated on our pipeline systems. 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 forward 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 delivery prices in the futures markets.

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 effect 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.

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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 by producers, refiners, utilities and trading entities has increased, 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 outright 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.

Geographic Data; Financial Information about Segments

See Note 15 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Company, LLC (Marathon) accounted for approximately 19%, 14% and 11% of our total revenues for each of the three years ended December 31, 2007, 2006 and 2005, respectively. Valero Marketing & Supply Company (Valero) accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company (Conoco) accounted for 11% of our revenues for the year ended December 31, 2007. BP Oil Supply accounted for 14% of our revenues for the year ended December 31, 2005. No other customers accounted for 10% or more of our revenues during any of the last three years. The majority of revenues from these customers 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 are exposed to significant competition based on the relatively low 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, investment banks that have established a trading platform, 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.

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 rules and regulations binding on the 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. We are cooperating in a Department of Justice/Environmental Protection Agency proceeding regarding certain releases of crude oil. The proceeding could result in injunctive remedies the effect of which would subject us to operational requirements and constraints that would not apply to our competitors. See Item 3. Legal Proceedings.

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.

Pipeline Safety

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. In addition, federal regulations require pipeline operators to implement measures designed to reduce the environmental impact of oil discharges from onshore oil pipelines. These regulations require operators to maintain comprehensive spill response plans, including extensive spill response training for pipeline personnel. 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 rules, which require 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. Segments of our pipelines that transport hazardous liquids in high consequence areas are subject to these DOT rules and therefore obligate us to evaluate pipeline conditions by means of periodic internal inspection, pressure testing, or other 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 the inspection, testing and correction of identified anomalies were approximately $15 million in 2007, $8 million in 2006 and $5 million in 2005. Based on currently available information, our preliminary estimate for 2008 is that we will incur approximately $12 million in operational expenditures and approximately $18 million in capital expenditures associated with our pipeline integrity management program. 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 (most of the operational expenditures and a much smaller portion of the capital expenditures) 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 rural onshore hazardous liquids gathering and low-stress pipeline systems found near unusually sensitive areas, including non-populated areas requiring extra protection because of the presence of sole source drinking water resources, endangered species, or other ecological resources. In December 2006, H.R. 5782, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the 2006 Pipeline Safety Act), which reauthorizes and amends the DOT s pipeline safety programs, became law. Included in the 2006 Pipeline Safety Act is a provision eliminating the regulatory exemption for hazardous liquid pipelines operated at low stress. While new regulations have not yet been adopted in response to the NPRM and the 2006 Pipeline Safety Act, DOT has indicated that it expects to adopt appropriate new rules for low stress pipelines during 2008. Although any new regulation of hazardous liquid low stress pipelines and any future regulation of hazardous liquid gathering lines could include requirements for the establishment of additional pipeline integrity management programs, we do not expect pending regulations to have a material impact on our operating expenses.

The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, for 2008 and beyond we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have added staff and implemented programs intended to improve the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have expanded an internal review process in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management mandate. The purpose of this process is to evaluate the surrounding environment, as well as the condition and operating history of these pipelines and gathering assets, to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from Environmental Protection Agency (EPA) enforcement actions, 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 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. See Item 3. Legal Proceedings Environmental.

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.

The DOT has adopted American Petroleum Institute Standard 653 (API 653) as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks 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 $18 million, $7 million and $4 million in 2007, 2006 and 2005, respectively. Based on currently available information, we anticipate we will spend an approximate average of $24 million per year for 2008 and 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 Resources Conservation Board (ERCB) and Saskatchewan Ministry of Energy 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 $6 million in 2007, $5 million in 2006 and $5 million in 2005 on compliance activities. Our preliminary estimate for 2008 is approximately $7 million. Certain of these costs are recurring in nature and thus will affect 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

Our pipeline assets and transportation activities are subject to several transportation regulations. Our historical and projected operating costs reflect the recurring costs resulting from compliance with these regulations, and we do not anticipate material expenditures in excess of these amounts in the absence of future acquisitions or changes in regulation, or discovery of existing but unknown compliance issues. The following is a summary of the transportation regulations that may impact our operations.

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 ERCB. 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.

Regulation of OCS Pipelines. The Outer Continental Shelf Lands Act (OCSLA) requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. In April 2007, the Minerals Management Service (MMS) issued a notice of proposed rulemaking that would establish a process for a shipper transporting oil or gas production from OCS leases to follow if it believes it has been denied open and nondiscriminatory access to OCS pipelines. We have no way of knowing what rules the MMS will ultimately adopt regarding access to OCS transportation, however, such rules are not expected to have a material impact on our operations or results.

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, which 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%. 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) to 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 FERC s current income tax allowance 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 tax allowance policy was upheld by the D.C. Circuit on May 29, 2007. FERC continues to refine its tax allowance policy in case-by-case reviews; how the Policy Statement is applied in practice to pipelines owned by MLPs could affect the rates of pipelines regulated by FERC.

The D.C. Circuit s May 29, 2007 decision also held that the FERC s determination that a rate is no longer subject to grandfathering protection under the EP Act 1992 when there has been a substantial change in the overall rate of return of the pipeline, rather than in one cost element. Further, the D.C. Circuit declined to consider arguments that there were errors in the FERC s method for determining substantial change, finding that the parties had not first raised such allegations with FERC. On August 20, 2007, the D.C. Circuit denied a petition for rehearing of the May 29 decision with respect to the alleged errors in the FERC s method for determining substantial change and the decision is now final.

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 transportation segment profit 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, facility inspection, reporting and safety.

Cross Border Regulation

As a result of our Canadian acquisitions and cross border activities, including importation of crude oil between the United States and Canada, 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. In addition, FERC s authority extends to maintenance of accounts and records, terms and conditions of service, depreciation and amortization policies, acquisition and disposition of facilities, initiation and discontinuation of services and relationships between pipelines and storage companies and certain affiliates.

Absent an exemption granted by the FERC, FERC s Standards 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 U.S. storage facility operators to their affiliated gas marketing entities. 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 storage companies, 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.

Under the Energy Policy Act of 2005 (EP Act 2005) and related regulations, it is 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, which implements the antimanipulation provision of EP Act 2005. Pursuant to EP Act 2005 and Order No. 670, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of FERC 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 EP Act 2005 also gives 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. 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, the FERC, state commissions and the courts.

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 could 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 subject us to additional operational requirements and constraints. Environmental and safety 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.

The following is a summary of some of the environmental and safety laws and regulations to which our operations are subject.

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 $350 million for onshore facilities. However, a party cannot take advantage of this liability limit if the spill is caused by gross negligence or willful misconduct, resulted from a violation of a federal safety, construction, or operating regulation, or if there is a failure to report a spill or cooperate in the cleanup. We believe that we are in substantial compliance with applicable OPA requirements. 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 federal, 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 Regulations Pipeline Safety and Note 11 to our Consolidated Financial Statements. Permits or approvals must be obtained to discharge pollutants into these waters. A permit is also required for the discharge of dredge and fill material into regulated waters, including wetlands. Federal, state and provincial regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. 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.

Air Emissions

Our operations are subject to the U.S. Clean Air Act (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. In addition, states can impose air emissions limitations that are more stringent than the federal standards imposed by EPA. Federal, state and provincial regulatory agencies can also impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. 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.

In response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (the Regulatory Framework) for regulating air pollution and industrial greenhouse gas emissions (GHG) by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations are expected to come into force in 2010 and targets would be based on percentages rather than absolute reductions. The Regulatory Framework also proposes a credit emissions trading system. Additionally, regulation can take place at the provincial and municipal level. For example, Alberta introduced the *Climate Change and Emissions Management Act,* which provides a framework for managing GHG by reducing specified gas emissions relative to gross domestic product to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020 and which imposes duties to report. The accompanying regulation, the *Specified Gas Emitters Regulation,* effective July 1, 2007, requires mandatory emissions reductions through the use of emissions intensity targets. The Canadian federal government proposes to enter into equivalency agreements with provinces that establish a regulatory regime to ensure consistency with the federal plan, but the success of any such proposal remains in doubt.

Although the United States is not participating in the Kyoto Protocol, the current session of Congress is considering climate-change related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act, would require a 70% reduction in emissions of greenhouse gases (from sources within the United States) between 2012 and 2050. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. 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. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in Massachusetts that greenhouse gases fall under the Clean Air Act s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New 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 could adversely affect our operations and demand for our services.

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.

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Occupational Safety and Health

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, recordkeeping requirements and monitoring of occupational exposure to regulated substances.

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 become subject to 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.

Environmental Remediation

We currently own or lease properties where hazardous liquids, including hydrocarbons, are or have been handled. These properties and the hazardous liquids or associated 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 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 environmental risk 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 sites requiring remediation that 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, 2007, we had incurred approximately $11 million of remediation costs associated with these sites; SOP s share is approximately $3 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.

In connection with our 1999 acquisition of Scurlock Permian LLC from Marathon Ashland Petroleum (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 million. The remediation obligation for certain sites such as at the products terminal at Paulsboro, New Jersey, is being contested. See Item 3. Legal Proceedings.

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

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 1,500% 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. 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 3,100 employees at December 31, 2007. None of the employees of our general partner were subject to a collective bargaining agreement, except for eight employees with whom we have a collective bargaining agreement that will end on September 30, 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 our 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. 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 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 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 subject us to additional operational requirements and constraints, 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 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 four years ago. We have also increased our terminalling and storage capacity and operate several facilities on or near navigable waters and domestic water supplies. As we have expanded our asset base, we have observed an increase in the number of releases of liquid hydrocarbons into 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 and 2007, we acquired refined products pipeline and terminalling assets. These assets 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 a 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 devote substantial resources 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. While new regulations have not yet been adopted, DOT has indicated that it expects to adopt appropriate new rules during 2008. These regulations will include requirements for the establishment of additional pipeline integrity management programs.

The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, for 2008 and beyond we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have added staff and implemented programs intended to improve the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have expanded an internal review process pursuant to which we review various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management mandate. 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, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from EPA enforcement actions, 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. See Item 3. Legal Proceedings Environmental.

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 counterparties. For example, our ability to utilize our crude oil storage capacity for merchant activities to capture contango market opportunities is dependent upon having adequate credit facilities, including the total amount of credit facilities and the cost of such credit facilities, which enables us to finance the storage of the crude oil from the time we complete the purchase of the oil until the time we complete the sale of the oil

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 Pine Prairie joint venture and the Paulsboro and Patoka terminal projects. Many of these projects involve numerous regulatory, environmental, commercial, 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 transportation segment profit is derived from pipeline transportation tariff 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. In addition, any significant production disruption from OCS fields and the San Joaquin Valley due to production problems, transportation problems or other reasons could have a material adverse effect on our business. 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 $7 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated $3 million decrease in annual transportation segment profit.

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.

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.

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 transportation 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.

Our results of operations are influenced by the overall forward market for crude oil, and certain market structures or the absence of pricing volatility may adversely impact our results.

Results from our marketing segment are influenced by the overall forward market for crude oil. A contango market (meaning that the price of crude oil for future deliveries is higher than current prices) is favorable to commercial strategies that are associated with storage tankage as it allows a party to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market (meaning that the price of crude oil for future deliveries is lower than current prices) has a positive impact on lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries; however, in this environment there is little incentive to store crude oil as current prices are above future delivery prices. In either case, margins can be improved when prices are volatile. The periods between these two market structures 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 effect 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 least beneficial environment for our marketing segment.

The wide contango spreads experienced over the last couple of years, combined with the level of price structure volatility during that time period, has had a favorable impact on our results. If the market remains in the slightly backwardated to transitional structure that has generally prevailed since July 2007, our future results from our marketing segment may be less than those generated during the more favorable contango market conditions that prevailed throughout most of 2005 and 2006 and the first half of 2007. Moreover, a prolonged transition period or a lack of volatility in the pricing structure may further negatively impact our results.

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

Our ability to grow our distributions 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.

In evaluating acquisitions, we generally prepare one or more financial cases based on a number of business, industry, economic, legal, regulatory, and other assumptions applicable to the proposed transaction. Although we expect a reasonable basis will exist for those assumptions, the assumptions will generally involve current estimates of future conditions, which are difficult to predict. Realization of many of the assumptions will be beyond our control. Moreover, the uncertainty and risk of inaccuracy associated with any financial projection will increase with the length of the forecasted period. Some acquisitions may not be accretive in the near term, and will be accretive in the long term only if we are able timely and effectively to integrate the underlying assets and such assets perform at or near the levels anticipated in our acquisition projections.

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

We continuously consider potential acquisitions and opportunities for internal growth. 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 or internal growth project will require access to capital. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our growth 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 growth 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 U.S. and Canadian pipeline system may reduce the amount of cash we generate.

Our U.S. 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.

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.

For our U.S. 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. Such 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, investment banks, 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 interest in PAA/Vulcan s natural gas storage operations, it competes 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 PAA/Vulcan s facilities. Third-party construction of new capacity could have an adverse impact on PAA/Vulcan s 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.

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 merger) is dependent on our ability to receive waterborne crude oil, a major portion of which is presently being received through dock facilities operated by a third party 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. In addition, our future debt level may limit our future financial and operating flexibility.

As of December 31, 2007, our consolidated debt outstanding was approximately $3.6 billion, consisting of approximately $2.6 billion principal amount of long-term debt (including senior notes) and approximately $1.0 billion of short-term borrowings. As of December 31, 2007, we had $1.0 billion of available borrowing capacity under our senior unsecured revolving credit facility.

The amount of our current or future indebtedness could have significant effects on our operations, including, among other things:

- a significant portion of our cash flow will be dedicated to the payment of principal and interest on our indebtedness and may not be available for other purposes, including the payment of distributions on our units and capital expenditures;

- credit rating agencies may view our debt level negatively;

- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;

- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;

- we may be at a competitive disadvantage relative to similar companies that have less debt; and

- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

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 certain debt coverage ratio. Our senior notes do not restrict distributions to unitholders, but a default under our credit agreements will be treated as a default under the senior notes. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facilities and Long-Term Debt.

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, our operating and financial performance the amount of our debt maturing in the next several years and current maturities and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, be unable to receive open credit from our suppliers and trade counterparties, be unable to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market or suffer a reduction in the market price of our common units. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we might be forced to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

Increases in interest rates could adversely affect our business and the trading price of our units.

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our credit facilities. As of December 31, 2007, we had approximately $3.6 billion of consolidated debt, of which approximately $2.6 billion was at fixed interest rates and approximately $1.0 billion was at variable interest rates (including $80 million of interest rate derivatives that swap fixed-rate debt for floating). From time to time we use interest rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, increases in interest rates could adversely affect our marketing segment results by increasing interest costs associated with the storage of hedged crude oil and LPG inventory. Further, the trading price of our common units may be sensitive to changes in interest rates and any rise in interest rates could adversely impact such trading price.

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.

At December 31, 2007, we have $1.1 billion of goodwill, of which we recorded approximately $875 million upon completion of our merger with Pacific. The purchase price for the Pacific merger was approximately $2.5 billion. 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.

PAA/Vulcan s natural gas storage facilities are new and have limited operating history.

Although we believe that PAA/Vulcan s operating natural gas storage facilities are designed substantially to meet PAA/Vulcan s contractual obligations with respect to injection and withdrawal volumes and specifications, the facilities are new and have a limited operating history. If PAA/Vulcan fails to receive or deliver natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, PAA/Vulcan could incur significant costs to maintain compliance with PAA/Vulcan s 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 refined products assets. There are significant risks and costs inherent in our efforts to engage in these operations, including the risk that we might not be able to 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. The natural gas storage and refined products businesses may involve commercial and operational risks that are greater than we have previously assumed.

Federal, state or local regulatory measures could adversely affect PAA/Vulcan s natural gas storage business.

PAA/Vulcan s natural gas storage operations are subject to federal, state and local regulation. Specifically, PAA/Vulcan s natural gas storage facilities and related assets are subject to regulation by the FERC, the Michigan Public Service Commission and various Louisiana state agencies. PAA/Vulcan s facilities essentially have market-based rate authority from such agencies. Any loss of market-based rate authority could have an adverse impact on PAA/Vulcan s 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.

Joint venture and other investment 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 Private Equity I LLC (Vulcan Capital). We are also engaged in an investment arrangement with Settoon Towing. Joint venture arrangements typically include provisions designed to allow each venturer to participate at some level in the management of the venture and to protect such venturer s investment.

As a result, differences in views among the venture participants may result in delayed decisions or in failures to agree on major matters, such as large expenditures or contractual commitments, the construction or acquisition of assets or borrowing money, among others. Delay or failure to agree may prevent action with respect to such matters, even though such action may serve our best interest or that of the venture. Accordingly, delayed decisions and failures to agree can potentially adversely affect the business and operations of the ventures and in turn our business and operations.

From time to time, enterprises in which we have interests may be involved in disputes or legal proceedings which, although not involving a loss contingency to us, may nonetheless have the potential to negatively affect our investment. For example, Settoon Towing is party to a lawsuit involving allegations that a Settoon barge struck a wellhead, causing the release of oil into the Intracoastal Canal.

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 our 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 our 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 our 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. Any new owner of our general partner would be able 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.

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 California Public Utilities Commission, 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, 2007, 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.

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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 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

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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 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 additional amounts of entity-level taxation for state or foreign tax purposes, it would reduce the amount of cash available to pay distributions and our debt obligations.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. 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. Therefore, treatment of us as a corporation would result in a material reduction in cash flow and after-tax returns to our unitholders, likely causing a substantial reduction in the value of our units.

Current law may change causing 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 and other forms of taxation. Specifically, beginning in 2008, we will be subject to a new entity level tax on the portion of our income that is generated in Texas in the prior year. Imposition of any such additional taxes on us will reduce the cash available for distribution to our unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, our target distribution amounts will be adjusted to reflect the impact of that law on us.

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

In June 2007, the Canadian government passed legislation that imposes entity-level taxes on certain types of flow-through entities. The legislation refers to safe harbor guidelines that grandfather certain existing entities and delay the effective date of such legislation until 2011 provided that the entities do not exceed the normal growth guidelines. Although limited guidance is currently available, we believe that the legislation will apply to our Canadian partnerships. We believe that we are currently within the normal growth guidelines as defined in the legislation, which should delay the effective date until 2011. However, future acquisitions could be subject to an entity-level tax prior to 2011. Entity-level taxation of our Canadian flow-through entities will reduce cash available for distributions or to pay 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 been terminated for tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold is reached, multiple sales of the same interest are counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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.

The IRS has made no determination as to our status as a partnership for federal income tax purposes or as to any other 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 agree with some or all of our counsel s conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution or debt service.

Our unitholders may be required to pay taxes on their share of our income 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 receive no 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 that income.

Tax gain or loss on the disposition of our common units could be more or less 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. Because distributions in excess of a unitholder s allocable share of our net taxable income decrease the unitholder s tax basis in their common units, the amount of any such prior excess distributions with respect to their units will, in effect, become taxable income to the unitholder if the common units are sold at a price greater than the unitholder s tax basis in those common units, even if the price the unitholder receives is less than the unitholder s original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may 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, 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 non-U.S. 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 employee benefit plans and 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 IRAs 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. Tax-exempt entities and non-U.S. persons should consult their tax advisor before investing in our common units.

We treat each purchaser of our 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 our common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing 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 the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders tax returns.

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state, local and foreign 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 now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in most states in the United States and Canada, most of which impose a personal income tax on individuals and an income tax on corporations and other entities. It is our unitholders responsibility to file all United States federal, state, local and foreign tax returns.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

The tax treatment of (i) publicly traded partnerships or (ii) an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of (i) publicly traded partnerships, including us, or (ii) an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. Although the currently proposed legislation would not appear to affect our treatment as a partnership, we are unable to predict whether any of these changes, or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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 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 $4 million to $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 civil penalty enforcement action under the Federal Clean Water Act. We have cooperated in the investigation and are currently involved in settlement discussions with DOJ and EPA. Our assessment is that it is probable we will pay penalties related to the two releases. We may also be subjected to injunctive remedies that would impose additional requirements and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency, which is included in the estimated aggregate costs set forth above. We understand that the maximum permissible penalty, if any, that EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. We believe that several mitigating circumstances and factors exist that are likely to substantially reduce any penalty that might be imposed by EPA, and will continue to engage in discussions with EPA and the DOJ with respect to such mitigating circumstances and factors, as well as any injunctive remedies proposed.

On November 15, 2006, we completed the Pacific merger. 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. Total projected emergency response, remediation and restoration costs are approximately $26 million, substantially all of which have been incurred. We anticipate that the majority of costs associated with this release will be covered under a pre-existing PPS pollution liability insurance policy. Substantially all of the costs that were incurred as of December 31, 2007 have been recovered under the 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, if any, that can be assessed is estimated to be approximately $1.4 million in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of crude oil recovered, and the State of California has the discretion to further reduce the fine, if any, 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 alleged 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 any natural resource damages amount. We believe that the alleged violations are without merit and intend to defend against them, and that defenses and mitigating factors should apply. We are currently involved in settlement discussions with the State of California.

The EPA has referred this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. We understand that the maximum permissible penalty, if any, that the EPA could assess under relevant statutes would be approximately $4.2 million. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty that might be imposed by the EPA, and intend to pursue discussions with the EPA regarding such defenses and mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be claimed by the EPA cannot be ascertained. While we have established an estimated loss contingency for this matter, we are presently unable to determine whether the March 2005 spill incident may result in a loss in excess of our accrual for this matter. Discussions with the DOJ to resolve this matter have commenced.

Pacific Atlantic Terminals. 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 various locations, including northern California, the Philadelphia, Pennsylvania metropolitan area, and Paulsboro, New Jersey. In the process of integrating PAT s assets into our operations, we identified certain aspects of the operations at the California 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 have cooperated with the District s review of these matters. Although we are currently unable to determine the outcome of the foregoing, at this time, we do not believe it will have a material impact on our financial condition, results of operations or cash flows.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE contamination at PAT s facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to $12 million. Both Exxon and GATX were prior owners of the terminal. We are in dispute with Kinder

Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific s purchase of the facility. In a related matter, the New Jersey Department of Environmental Protection has brought suit against GATX and Exxon to recover natural resources damages. Exxon and GATX have filed third-party demands against PAT, seeking indemnity and contribution. We intend to vigorously defend against any claim that PAT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in the imposition of fines and penalties. For example, we were informed by the EPA that a terminal owned by Rocky Mountain Pipeline Systems LLC (RMPS), one of the subsidiaries acquired in the Pacific merger, was purportedly out of compliance with certain regulatory documentation requirements. Upon review, we found similar issues at other RMPS terminals. We have settled these matters with EPA.

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 or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil 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 help prevent releases, 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 procedures, remove selected assets from service and spend capital to upgrade the assets. See Items 1 and 2. Business and Properties Regulation Pipeline Safety. However, the inclusion of additional miles of pipe in our operations 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 purchase of assets from Link Energy LLC in April 2004, 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, including a Section 308 request received in late October 2007 with respect to a 400-barrel release of crude oil, a portion of which reached a tributary of the Colorado River in a remote area of West Texas. See Pipeline Releases above.

At December 31, 2007, our reserve for environmental liabilities totaled approximately $36 million, of which approximately $15 million is classified as short-term and $21 million is classified as long-term. At December 31, 2007, we have recorded receivables totaling approximately $7 million for amounts that are probable of recovery 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, costs incurred in excess of this reserve may be higher and may potentially have a material adverse effect on our financial condition, results of operations, or cash flows.

Other. A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our environmental activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial condition, results of operations or cash flows.

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

None.

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, 2008, the closing market price for our common units was $47.24 per unit and there were approximately 69,000 record holders and beneficial owners (held in street name). As of February 20, 2008, there were 115,981,676 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)
2007			
4th Quarter	$ 57.09	$ 46.25	$ 0.8500
3rd Quarter	65.24	52.01	0.8400
2nd Quarter	64.82	56.32	0.8300
1st Quarter	59.33	49.56	0.8125
2006			
4th Quarter	$ 53.23	$ 45.20	$ 0.8000
3rd Quarter	47.35	43.21	0.7500
2nd Quarter	48.92	42.81	0.7250

1st Quarter	47.00	39.81	0.7075

(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.

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Cash Distribution Policy

We will distribute all of our available cash to our unitholders on a quarterly basis 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. Following the distribution in February 2008, the aggregate remaining incentive distribution reduction was $41 million.

We paid $73 million to the general partner in incentive distributions in 2007. On February 14, 2008, we paid a quarterly distribution of $0.85 per unit applicable to the fourth quarter of 2007, of which approximately $25 million was paid to the general partner. 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 2007, and we do not have any announced or existing plans to repurchase any of our common units.

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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, 2007, 2006, 2005, 2004 and 2003 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,				
	2007	2006	2005	2004	2003
	(in millions, except for per unit and volume data)				
Statement of operations data:					
Total revenues(1)	$ 20,394	$ 22,445	$ 31,177	$ 20,975	$ 12,590
Crude oil and LPG purchases and related costs(1)	19,001	21,486	30,443	20,424	12,233
Field operating costs	531	370	273	220	140
General and administrative expenses	164	134	103	83	73
Depreciation and amortization	180	100	84	69	46
Total costs and expenses	19,876	22,090	30,903	20,796	12,492
Operating income	518	355	274	179	98
Interest expense	(162)	(86)	(59)	(47)	(35)
Equity earnings in unconsolidated entities	15	8	2	1	
Interest and other income (expense), net	10	2	1		(4)
Current income tax expense	(3)				
Deferred income tax expense	(13)				
Income before cumulative effect of change in accounting principle(2)	365	279	218	133	59
Cumulative effect of change in accounting principle		6		(3)	
Net income	$ 365	$ 285	$ 218	$ 130	$ 59
Basic net income before cumulative effect of change in accounting principle(2)	$ 2.54	$ 2.84	$ 2.77	$ 1.94	$ 1.01
Diluted net income before cumulative effect of change in accounting principle(2)	$ 2.52	$ 2.81	$ 2.72	$ 1.94	$ 1.00
Basic weighted average number of limited partner units outstanding	113	81	69	63	53
Diluted weighted average number of limited partner units outstanding	114	82	70	63	53
Balance sheet data (at end of period):					
Total assets	$ 9,906	$ 8,715	$ 4,120	$ 3,160	$ 2,096
Total long-term debt	2,624	2,626	952	949	519
Total debt	3,584	3,627	1,330	1,125	646

Partners capital		3,424		2,977		1,331		1,070		747
Other data:										
Maintenance capital expenditures	$	50	$	28	$	14	$	11	$	8
Net cash provided by (used in) operating activities(3)		796		(276)		24		104		115
Net cash used in investing activities(3)		(663)		(1,651)		(297)		(651)		(272)
Net cash provided by (used in) financing activities		(124)		1,927		271		555		157
Declared and paid distributions per limited partner unit(4)		3.28		2.87		2.58		2.30		2.19

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	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(in millions, except for per unit and volume data)				
Volumes(5)					
Transportation segment (average daily volumes in thousands of barrels):					
Tariff activities	2,712	2,106	1,799	1,486	902
Trucking	105	101	84	64	52
Transportation Activities Total	2,817	2,207	1,883	1,550	954
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	38	21	17	15	12
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	13	13	4		
LPG processing (thousands of barrels per day)	18	12			
Facilities Activities Total (average monthly capacity in millions of barrels)(6)	41	23	18	15	12
Marketing segment (average daily volumes in thousands of barrels):					
Crude oil lease gathering	685	650	610	589	437
Refined products	11	N/A	N/A	N/A	N/A
LPG sales	90	70	56	48	38
Waterborne foreign crude imported	71	63	59	12	N/A
Marketing Activities Total	857	783	725	649	475

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

(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 million, $136 million and $66 million for 2005, 2004 and 2003, 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) and $1.13 ($1.12 diluted) for 2005, 2004 and 2003, 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 million for 2003. 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) for 2003.

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

(4) Our general partner is entitled, directly or indirectly, 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.

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

(6) 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 and crude processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly capacity 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
- Prospects for the Future
- Acquisitions and Internal Growth Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements and Changes in Accounting Principles
- 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 are involved in the development and operation of natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries.

We 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, gathering systems, trucks and barges. The transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. 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. The facilities segment generates 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 with the purchase and sale of crude oil, refined products 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 potential associated with opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a counter-cyclical balance.

Overview of Operating Results, Capital Spending and Significant Activities

During 2007, we recognized net income of $365 million and earnings per diluted limited partner unit of $2.52, compared to net income of $285 million and earnings per diluted limited partner unit of $2.88 during 2006. Net income was $218 million and earnings per diluted limited partner unit was $2.72 for 2005. Key items impacting 2007 include:

Income Statement

Contributions from the November 2006 Pacific acquisition as well as eight additional acquisitions throughout 2006. We also made four acquisitions during 2007 but their impact on 2007 net income is not material due to their partial year contribution.

Favorable execution of our risk management strategies around our marketing assets in a market with a high level of crude oil volatility.

A gain of approximately $12 million on the sale of pipeline linefill.

A loss of approximately $24 million related to the mark-to-market impact for open derivative instruments (compared to a loss of approximately $4 million for 2006).

An increase in costs and expenses primarily associated with additional assets resulting from internal growth projects and acquisitions.

Increased equity compensation plan expense of $49 million (compared to $43 million for 2006), primarily resulting from additional Long-Term Incentive Plan (LTIP) grants.

Deferred tax expense of approximately $10 million primarily pertaining to recently enacted Canadian tax legislation.

Balance Sheet and Capital Structure

The completion of four acquisitions in 2007 for aggregate consideration of approximately $123 million.

Capital expenditures for internal growth projects of $525 million in 2007.

The sale of approximately 6 million limited partner units in 2007 for net proceeds of approximately $383 million. Our earnings per unit data for 2007 compared to 2006 is also impacted by the sale of approximately 6 million limited partner units in December 2006 (for net proceeds of approximately $306 million) and the November 2006 issuance of approximately 22 million limited partner units (valued at approximately $1.0 billion) in exchange for Pacific limited partner units as part of the Pacific acquisition.

Prospects for the Future

During 2007, we grew our business by expanding our asset base through approximately $123 million of acquisitions and $525 million of internal growth projects. In 2008, we intend to spend approximately $330 million on internal growth projects and also to continue to develop our inventory of projects for implementation beyond 2008. Several of the larger storage tank projects for 2008, such as the construction or expansion of the Patoka and Paulsboro 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. We will continue to look for ways to grow these businesses. 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 portions of the North American midstream infrastructure.

Although we believe that we are well situated in the North American midstream infrastructure, we face various operational, regulatory, financial and competitive 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.

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Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2007, 2006 and 2005 that have impacted our results of operations and, combined with prudent financing, enabled us to enhance our liquidity, as discussed herein. The following table summarizes our capital expenditures for acquisitions, including investments in unconsolidated entities, internal growth projects and maintenance capital for the periods indicated (in millions):

	For the Year Ended December 31,		
	2007	2006	2005
Acquisition capital	$ 125	$ 3,021	$ 40
Investment in unconsolidated entities	9	44	113
Internal growth projects	525	332	149
Maintenance capital	50	28	14
	$ 709	$ 3,425	$ 316

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 approximately 58% in 2007 compared to 2006. Our 2007 projects included the construction and expansion of pipeline systems and crude oil storage and terminal facilities. The following table summarizes our 2007 and 2006 projects (in millions):

Projects	**2007**	**2006**
St. James, Louisiana Storage Facility(1)	$ 82	$ 83
Salt Lake City Expansion(1)	72	2
Cheyenne Pipeline	58	10
Patoka Tankage(1)	30	
Cushing Tankage Phase VI(1)	29	10
Martinez Terminal(1)	26	
Elk City to Calumet(1)	14	
Fort Laramie Tank Expansion(1)	12	
Kerrobert Tankage	10	29
Pier 400(2)	6	
Other Projects(3)	186	198
Total	$ 525	$ 332

(1) These projects will continue into 2008 and we expect to incur an additional $105 million to $115 million in 2008 with respect to such projects. See Liquidity and Capital Resources Capital Expenditures and Distributions Paid to Unitholders and General Partners 2008 Capital Expansion Projects.

(2) This project requires approval of a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time.

(3) Primarily pipeline connections, upgrades and truck stations as well as new tank construction and refurbishing.

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 acquisition and capital expansion activities are discussed further in Liquidity and Capital Resources and in Note 3 to our Consolidated Financial Statements.

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2007 Acquisitions

In 2007, we completed four acquisitions for aggregate consideration of approximately $123 million. See Note 3 to our Consolidated Financial Statements. The following table summarizes the acquisitions that were completed in 2007 (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Bumstead LPG Storage Facility	7/24/2007	$ 52	Facilities
Tirzah LPG Storage Facility	10/2/2007	54	Facilities
Other	Various	17	Marketing and Transportation
Total		$ 123	

2006 Acquisitions

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

Acquisition	Effective Date	Acquisition Price	Operating Segment
Pacific	11/15/2006	$ 2,456	Transportation, Facilities and Marketing
Andrews	4/18/2006	220	Transportation, Facilities and Marketing
SemCrude	5/1/2006	129	Marketing
BOA/CAM/HIPS	7/31/2006	130	Transportation
El Paso-to-Albuquerque Products Pipeline	9/1/2006	66	Transportation
Other	Various	20	Transportation, Facilities and Marketing
Total		$ 3,021	

Pacific. On November 15, 2006 we completed our merger with 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 million Pacific common units and approximately 5 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. See Note 3 to our Consolidated Financial Statements for discussion of the purchase price and related allocation, and discussion of the sources of funding.

Other 2006 Acquisitions. In addition, in November 2006, we purchased a 50% interest in Settoon Towing for approximately $34 million. Settoon Towing owns and operates a fleet of 62 transport and storage barges as well as 32 transport tugs. Its core business is the gathering and transportation of crude oil and produced water from inland production facilities across the Gulf Coast.

2005 Acquisitions

We completed six small transactions in 2005 for aggregate consideration of approximately $40 million. The transactions included Canadian 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

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materially impact our results of operations, either individually or in the aggregate. The following table summarizes the 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	Transportation
Tulsa LPG Pipeline	3/2/2005	10	Marketing
Other acquisitions	Various	18	Transportation, Facilities, Marketing
Total		$ 40	

(1) The total purchase price was $24 million. 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 $113 million capital contribution to PAA/Vulcan and we account for our 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.

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 estimates 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 approximately 3% 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 5% of total operating income and less than 7% 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 Statement of Financial Accounting Standards (SFAS) No. 133 Accounting For Derivative Instruments and Hedging Activities, as amended (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. Approximately 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.

Accruals and Contingent Liabilities. We record accruals or 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 5% in our aggregate estimate for the contingent liabilities discussed above would have an approximate $5 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 No. 141 Business Combinations, 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. 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 did not have any impairments in 2007, 2006 or 2005. See Note 3 to our Consolidated Financial Statements for discussion of our acquisitions.

Equity Compensation Plan Accruals. We accrue compensation expense for outstanding equity awards granted under our various Long Term Incentive Plans as well as outstanding Class B units of Plains AAP, L.P. Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the service period. For equity awards that contain a performance condition, the fair value of the equity award is recognized as compensation expense only if the attainment of the performance condition is considered probable.

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For equity awards granted under our various Long Term Incentive Plans, the total compensation expense recognized over the service period is determined by our unit price on the vesting date (or, in some cases, the average unit price for a range of dates preceding the vesting date) multiplied by the number of equity awards that are vesting, plus our share of associated employment taxes. Uncertainties involved in this estimate include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity awards.

For the Class B units of Plains AAP, L.P., the total compensation expense recognized over the service period is equal to the grant date fair value of the Class B units that become earned. The Class B units become earned in 25% increments upon PAA achieving annualized distribution levels of $3.50, $3.75, $4.00 and $4.50 (or, in some cases, within six months thereof). When earned, the Class B units will be entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million per quarter. Uncertainties involved in this estimate include the estimated date that PAA will achieve the annualized distribution levels required and the continued employment of personnel who have been awarded Class B units.

We recognized total compensation expense of approximately $49 million in 2007 and $43 million in 2006 related to equity awards granted under our various equity compensation plans. We cannot provide assurance that the actual fair value of our equity compensation awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.

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 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.

Impairments were not material in 2007, 2006 and 2005.

Recent Accounting Pronouncements and Changes in Accounting Principles

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 Principles

Stock-Based Compensation. In December 2004, Statement of Financial Accounting Standard No. 123 (revised 2004), Share-Based Payment (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 gain of approximately $6 million due to the cumulative effect of change in accounting principle. 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 an 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. Our LTIP awards are classified as liabilities under SFAS 123(R) as the awards are primarily paid in cash. Under the modified prospective transition method, we are not required to adjust our prior period financial statements for our LTIP awards.

Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the Emerging Issues Task Force (EITF) issued Issue No. 04-13 (EITF 04-13), Accounting for Purchases and Sales of Inventory with the Same Counterparty. The EITF concluded that inventory purchase and sale transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 became effective in reporting periods beginning after March 15, 2006.

We adopted EITF 04-13 on April 1, 2006. The adoption of EITF 04-13 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. In conformity with EITF 04-13, prior periods are not affected, although we have parenthetically disclosed prior period buy/sell transactions in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases on our income statement but does not impact our financial position, net income, or liquidity.

Results of Operations

	For the Twelve Months Ended December 31,		
	2007	2006	2005
		(In millions)	
Transportation segment profit	$ 334	$ 200	$ 170
Facilities segment profit	110	35	15
Marketing segment profit	269	228	175
Total segment profit	713	463	360
Depreciation and amortization	(180)	(100)	(84)
Interest expense	(162)	(86)	(59)
Interest income and other income (expense), net	10	2	1
Income tax expense	(16)		
Income before cumulative effect of change in accounting principle	365	279	218
Cumulative effect of change in accounting principle		6	
Net income	$ 365	$ 285	$ 218

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing.

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities 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. We look at each period s earnings before non-cash depreciation and amortization as an important measure of segment performance.

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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. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which act to partially offset the wear and tear and age-related decline in the value of our principal fixed assets. These maintenance investments 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, not maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life, improve the efficiency, or expand the operating capacity of the asset 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 or at the same rates as those charged to third-party shippers. Facilities segment services are also obtained at rates generally 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. Inter-segment rates are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. We also allocate certain operating expense and general and administrative overhead expenses between segments. We believe that the estimates with respect to these allocations are reasonable.

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Transportation

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

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	$	%	$	%
Operating Results (1) (in millions, except per barrel amounts)							
Revenues							
Tariff activities	$ 654	$ 438	$ 375	$ 216	49%	$ 63	17%
Trucking	117	96	60	21	22%	36	60%
Total transportation revenues	771	534	435	237	44%	99	23%
Costs and Expenses							
Trucking costs	(80)	(71)	(50)	(9)	(13)%	(21)	(42)%
Field operating costs (excluding equity compensation charge)	(288)	(201)	(164)	(87)	(43)%	(37)	(23)%
Equity compensation charge operations(2)	(5)	(5)	(1)		%	(4)	(400)%
Segment G&A expenses (excluding equity compensation charge)(3)	(50)	(43)	(40)	(7)	(16)%	(3)	(8)%
Equity compensation charge general and administrative(2)	(19)	(16)	(11)	(3)	(19)%	(5)	(45)%
Equity earnings in unconsolidated entities	5	2	1	3	150%	1	100%
Segment profit	$ 334	$ 200	$ 170	$ 134	67%	$ 30	18%
Maintenance capital	$ 34	$ 20	$ 9	$ 14	70%	$ 11	122%
Segment profit per barrel	$ 0.34	$ 0.26	$ 0.26	$ 0.08	31%	$	%

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	Volumes	%	Volumes	%
Average Daily Volumes (thousands of barrels)(4) Tariff activities							
All American	47	49	51	(2)	(4)%	(2)	(4)%
Basin	378	332	290	46	14%	42	14%
Capline	235	160	132	75	47%	28	21%
Line 63/Line 2000	175	20	N/A	155	775%	20	N/A
Salt Lake City Area Systems	101	14	N/A	87	621%	14	N/A
West Texas/New Mexico Area Systems	386	433	428	(47)	(11)%	5	1%
Manito	73	72	63	1	1%	9	14%

Rangeland	63	24	N/A	39	163%	24	N/A
Refined products	109	24	N/A	85	354%	24	N/A
Other	1,145	978	835	167	17%	143	17%
Tariff activities total	2,712	2,106	1,799	606	29%	307	17%
Trucking	105	101	84	4	4%	17	20%
Transportation activities total	**2,817**	**2,207**	**1,883**	**610**	**28%**	**324**	**17%**

(1) Revenues and costs and expenses include intersegment amounts.

(2) Compensation expense related to our equity compensation plans.

(3) 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.

(4) 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.

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 generally reflects a negotiated amount.

Transportation segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues and volumes increased for 2007 compared to 2006 and for 2006 compared to 2005. The table below presents the significant variances in revenues (in millions) and average daily volumes (thousands of barrels) between 2007, 2006 and 2005:

	Revenues	Volumes
2007 compared to 2006		
Increase due to:		
Acquisitions(1)	$ 164	541
Basin and Capline Pipeline Systems(2)	30	122
Trucking(3)	21	4
Other(4)	22	(57)
Total variance	$ 237	610
2006 compared to 2005		
Increase due to:		
Acquisitions(1)	$ 33	178
Basin and Capline Pipeline Systems(5)	7	70
Canadian Pipeline Systems(6)	8	(7)
Other(4)	51	83
Total variance	$ 99	324

(1) Revenues and volumes for 2007 and 2006 were impacted by crude oil and refined products pipeline systems acquired or brought into service during 2007 and 2006 (primarily from the 2006 Pacific merger).

(2) The increase in volumes and revenues on the Basin system is primarily a result of new connection points that were constructed and brought online in 2007 as well as an increase in short-haul volumes on the Basin system. The increase in the Capline pipeline system volumes and revenues is primarily related to an existing shipper that

increased its movements of crude in 2007.

(3) Revenues were impacted by higher trucking revenues primarily resulting from an increase in trucking rates during 2007 and trucking businesses that were acquired in 2007 and 2006.

(4) Miscellaneous revenue and volume variances on various other systems.

(5) Volumes and revenues on our Basin and Capline pipeline systems increased in 2006 primarily as a result of multi-year contracts entered into during 2006.

(6) Revenues from some of our Canadian pipeline systems increased in 2006 primarily as a result of the appreciation of the 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). For 2007 compared to 2006, our revenues

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from our Canadian pipeline systems also increased as a result of the appreciation of the Canadian currency but were offset by miscellaneous other variances.

Field Operating Costs. Field operating costs have increased in most categories for 2007 and 2006 as we have continued to grow through acquisitions and expansion projects. The 2007 increased costs primarily relate to (i) payroll and benefits, (ii) maintenance, (iii) utilities, (iv) property taxes and (v) compliance with API 653 and pipeline integrity testing and maintenance requirements.

The most significant cost increases in 2006 compared to 2005 were related to (i) payroll and benefits, (ii) utilities, (iii) pipeline integrity testing and maintenance, and (iv) property taxes.

General and Administrative Expenses. Our G&A expenses were impacted in 2007 and 2006 by the following:

Segment G&A expense increased in 2007 compared to 2006 and in 2006 compared to 2005 primarily as a result of acquisitions and expansion projects.

Equity compensation charges increased approximately $3 million in 2007 compared to 2006 primarily as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

Equity compensation charges increased approximately $5 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. See Note 10 to our Consolidated Financial Statements.

Equity Earnings. Our transportation segment includes our equity earnings from our investments in Settoon Towing, Butte and Frontier. Barge transportation services are provided by Settoon Towing, in which we own a 50% equity interest. Butte and Frontier are pipeline systems in which we own approximately 22% and 22%, respectively. Our investments in Settoon Towing, Butte and Frontier contributed an aggregate of approximately $5 million, $2 million and $1 million in earnings for 2007, 2006 and 2005, respectively.

Maintenance Capital. For the years ended December 31, 2007, 2006 and 2005, maintenance capital investment for our transportation segment was approximately $34 million, $20 million and $9 million, respectively. The increases are due to our ownership of an increased number of assets and pipeline systems resulting from our continued growth through acquisitions and expansion projects and from general inflationary pressures that have adversely impacted the energy industry.

Facilities

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

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	$	%	$	%
Operating Results (1) (in millions, except per barrel amounts)							
Storage and terminalling revenues(1)	$ 210	$ 88	$ 42	$ 122	139%	$ 46	110%
Field operating costs (excluding equity compensation charge)	(84)	(39)	(18)	(45)	(115)%	(21)	(117)%
Segment G&A expenses (excluding equity compensation charge)(3)	(18)	(14)	(8)	(4)	(29)%	(6)	(75)%
Equity compensation charge general and administrative(2)	(8)	(6)	(2)	(2)	(33)%	(4)	(200)%
Equity earnings in unconsolidated entities	10	6	1	4	67%	5	500%
Segment profit	$ 110	$ 35	$ 15	$ 75	214%	$ 20	133%
Maintenance capital	$ 10	$ 5	$ 1	$ 5	100%	$ 4	400%
Segment profit per barrel	$ 0.22	$ 0.12	$ 0.07	$ 0.10	83%	$ 0.05	71%

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	Volumes	%	Volumes	%
Volumes(4)							
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	38	21	17	17	81%	4	24%
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	13	13	4		%	9	225%
LPG and crude processing (thousands of barrels per day)	18	12	N/A	6	50%	12	N/A
Facilities activities total (average monthly capacity in millions of barrels)(5)	41	23	18	18	78%	5	28%

(1) Revenues include intersegment amounts.

(2) Compensation expense related to our equity compensation plans.

(3) 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 business activities that exist during each period.

(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 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 capacity in millions.

Facilities segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues and volumes increased for 2007 compared to 2006 and for 2006 compared to 2005. The table below presents the significant variances in revenues (in millions) and volumes between 2007, 2006 and 2005:

	Volumes			
	Crude Oil, Refined Products and LPG Storage(1)	Natural Gas Storage(2)	LPG and Crude Processing(3)	Revenues
2007 compared to 2006				
Increase due to:				
Acquisitions(4)	13		6	$ 98
Expansions(5)	2			12
Other	2			12
Total variance	**17**		**6**	**$ 122**
2006 compared to 2005				
Increase due to:				
Acquisitions(6)	2	9	12	$ 26
Expansions(7)	1			2
Other	1			18
Total variance	**4**	**9**	**12**	**$ 46**

(1) Average monthly capacity (in millions of barrels).

(2) Average monthly capacity (in bcf).

(3) Barrels per day (in thousands).

(4) Revenues and volumes were primarily impacted in 2007 by acquisitions. The Pacific acquisition was completed in November 2006 and contributed additional revenues of approximately $75 million and additional volumes of approximately 12 million barrels for 2007 compared to 2006. The acquisition of the Shafter processing facility in April 2006 resulted in additional processing revenues of approximately $19 million (which also reflects an increase in internal fees and a wider market place) and additional volumes of approximately 6,000 barrels per day for 2007 compared to 2006. The Bumstead and Tirzah acquisitions in July 2007 and October 2007, respectively, in the aggregate contributed additional revenues of approximately $4 million and additional volumes of approximately 1 million barrels for 2007.

(5)

Expansion projects also resulted in an increase in revenues and volumes in 2007 compared to 2006. The St. James and Kerrobert expansion projects that were completed during 2007 contributed additional revenues of $10 million and $2 million, respectively, and additional aggregate volumes of approximately 2 million barrels for 2007.

(6) Revenues were primarily impacted in 2006 by acquisitions. The Pacific merger was completed in November 2006 and contributed additional revenues of approximately $12 million and additional volumes of approximately 2 million barrels for 2006 compared to 2005. The acquisition of the Shafter processing facility in April 2006 resulted in additional processing revenues of approximately $13 million and additional volumes of approximately 12 thousand barrels per day for 2006 compared to 2005. The utilization of capacity at the Mobile facility that was acquired from Link in 2004 but not used extensively until 2006 contributed approximately $1 million of additional revenues in 2006 compared to 2005. The acquisition of the Kimball gas storage facility by PAA/Vulcan contributed additional volumes of approximately 9 bcf for 2006 compared to 2005. See Equity Earnings below for discussion of the impact of the additional volumes on our equity earnings from PAA/Vulcan.

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(7) Expansion projects also resulted in an increase in revenues in 2006 compared to 2005. The Kerrobert expansion project that was completed during 2006 contributed additional revenues of $2 million and additional volumes of approximately 1 million barrels for 2006.

Field Operating Costs. Our field operating costs were impacted in 2007 and 2006 by the following:

Our continued growth, primarily from the acquisitions completed during 2007 and 2006 and the additional tankage added in 2007 and 2006, is the primary cause of the increase in field operating costs in 2007. Of the total increase for 2007 compared to 2006, $8 million relates to the operating costs (including increased utilities expense) associated with the Shafter processing facility that was acquired through the Andrews acquisition in April 2006, approximately $30 million relates to the operating costs associated with the Pacific acquisition that was completed in November 2006, and $1 million relates to the operating costs associated with the Bumstead and Tirzah acquisitions that were completed in July 2007 and October 2007, respectively. The St. James expansion project contributed approximately $2 million of additional operating costs for 2007 compared to 2006.

The acquisitions completed in 2006 and 2005, and the additional tankage added in 2006 and 2005 is the primary cause of the increase in field operating costs in 2006. Of the total increase, approximately $11 million relates to the operating costs associated with the Shafter processing facility and approximately $5 million relates to the operating costs associated with the Pacific acquisition.

General and Administrative Expenses. Our G&A expenses were impacted in 2007 and 2006 by the following:

Segment G&A expense excluding equity compensation charges increased in 2007 compared to 2006 and in 2006 compared to 2005 primarily as a result of acquisitions and expansions.

Equity compensation charges included in segment G&A expenses increased approximately $2 million in 2007 compared to 2006 principally as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

Equity compensation charges included in segment G&A expenses increased approximately $4 million in 2006 compared to 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. See Note 10 to our Consolidated Financial Statements.

Equity Earnings. Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. Our investment in PAA/Vulcan contributed approximately $4 million in additional earnings for 2007 compared to 2006, reflecting increased value for leased storage. PAA/Vulcan contributed approximately $5 million in additional earnings for 2006 compared to 2005, reflecting increased value for leased storage and additional storage capacity resulting from acquisitions.

Maintenance Capital. For the years ended December 31, 2007, 2006 and 2005, maintenance capital investment for our facilities segment was approximately $10 million, $5 million and $1 million, respectively. The increase in 2007 was primarily due to additional maintenance expenditures arising from the Pacific acquisition. The increase in 2006 was primarily due to additional maintenance expenditures at our Alto and Shafter facilities.

Marketing

Our revenues from marketing activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include 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 crude oil volumes, (ii) refined products volumes, (iii) LPG sales volumes and (iv) waterborne foreign crude imported) as well as the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. 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 risk management activities provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and will vary from period to period.

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

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	$	%	$	%
	(in millions, except per barrel amounts)						
Operating Results(1)							
Revenues(2)(3)	$ 19,858	$ 22,061	$ 30,893	$ (2,203)	(10)%	$ (8,832)	(29)%
Purchases and related costs(4)(5)	(19,366)	(21,641)	(30,579)	2,275	11%	8,938	29%
Field operating costs (excluding equity compensation charge)	(154)	(137)	(94)	(17)	(12)%	(43)	(46)%
Equity compensation charge operations(6)			(2)		%	2	100%
Segment G&A expenses (excluding equity compensation charge)(7)	(52)	(39)	(33)	(13)	(33)%	(6)	(18)%
Equity compensation charge general and administrative(6)	(17)	(16)	(10)	(1)	(6)%	(6)	(60)%
Segment profit(3)	$ 269	$ 228	$ 175	$ 41	18%	$ 53	30%
SFAS 133 mark-to-market loss(3)	$ (27)	$ (4)	$ (19)	$ (23)	(575)%	$ 15	79%
Maintenance capital	$ 6	$ 3	$ 4	$ 3	100%	$ (1)	(25)%
Segment profit per barrel(8)	$ 0.86	$ 0.80	$ 0.66	$ 0.06	8%	$ 0.14	21%

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	Volumes	%	Volumes	%
	(in thousands of barrels per day)						
Average Daily Volumes(9)							
Crude oil lease gathering	685	650	610	35	5%	40	7%
Refined products	11	N/A	N/A	11	100%	N/A	N/A

LPG sales	90	70	56	20	29%	14	25%
Waterborne foreign crude imported	71	63	59	8	13%	4	7%
Marketing Activities Total	857	783	725	74	9%	58	8%

(1) Revenues and costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $4,762 million, and $16,275 million for the years ended December 31, 2006 and 2005, 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 million and $16,107 million for the years ended December 31, 2006 and 2005, respectively. These 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 $44 million, $49 million and $24 million for the years ended December 31, 2007, 2006 and 2005, respectively.

(6) Compensation expense related to our equity compensation 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.

(8) Calculated based on crude oil lease gathered volumes, refined products 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.

Marketing segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Revenues and purchases and related costs. The variances between our revenues and purchases and related costs for 2007, 2006 and 2005 are described below.

Our revenues and purchases and related costs decreased for 2007 compared to 2006 and for 2006 compared to 2005 due to the adoption in the second quarter of 2006 of EITF 04-13. According to EITF 04-13, inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The adoption of EITF 04-13 in the second quarter of 2006 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases and related costs on our income statement but does not impact our financial position, net income or liquidity.

Our revenues and purchases and related costs for 2007 increased compared to 2006 and they increased for 2006 compared to 2005 partially due to an increase in the average NYMEX price for crude oil. The NYMEX average was $72.36 for 2007 compared to $66.27 for 2006 and $56.65 for 2005.

Our marketing segment profit was also impacted by the following:

During 2007 and 2006, the crude oil market experienced significantly high volatility in prices and market structure. The NYMEX benchmark price of crude oil ranged from approximately $50 to $99 during 2007 and from approximately $55 to $78 for 2006. The NYMEX WTI crude oil benchmark prices reached a record high of over $99 per barrel in November 2007 (which has been exceeded in 2008). The volatile market allowed us to utilize risk management strategies to optimize and enhance the margins of our gathering and marketing activities. The volatile market also led to favorable basis differentials for various delivery points and grades of crude oil during the first half of 2007. These favorable basis differentials began to narrow during the second half of the year.

From early 2005 through the end of June 2007, the market for crude oil generally was volatile and in contango, meaning that the price of crude oil for future deliveries was higher than current prices. A contango market is favorable to our commercial strategies that are associated with storage tankage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. In July 2007, the market for crude oil transitioned rapidly to a backwardated market, 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. However, in this environment, there is little incentive to store crude oil as current prices are above future delivery prices. The monthly timespread of prices averaged approximately $0.32 for 2007 ($1.24 contango for the first half of the year compared to $(0.58) backwardation for the second half of the year) versus an average contango spread of $1.22 for 2006 and $0.72 for 2005.

Revenues for 2007 include a mark-to-market loss under SFAS 133 of approximately $27 million compared to a loss of approximately $4 million for 2006 and a loss of approximately $19 million for 2005. These gains or losses are generally offset by physical positions that qualify for the normal purchase and normal sale exclusion under SFAS 133 and thus, are not included in the mark-to-market calculation. See Note 6 to our Consolidated Financial Statements for discussion of our hedging activities.

During 2006 and 2007, we purchased certain crude oil gathering assets and related contracts in South Louisiana, completed the acquisitions of Pacific and Andrews, and purchased a refined products supply and marketing business. These transactions primarily affected our transportation and facilities segment, but also included some marketing activities and opportunities. The integration into our business of these marketing activities precludes specific quantification of relative contribution, but we believe these acquisitions increased segment profit and revenues for our marketing segment.

In 2006, we recognized a $6 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 million of the charge relates to our crude oil inventory in third-party pipelines and the remainder relates to LPG and other products inventory.

Field operating costs increased in 2007 compared to 2006, primarily as a result of increases in (i) contract transportation as a result of 2006 acquisitions, (ii) fuel costs resulting from higher market prices and (iii) maintenance costs as a result of 2006 acquisitions.

Field operating costs 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 for 2007 compared to 2006 was primarily the result of increased payroll and benefits (partly due to the retirement of an executive), as well as acquisitions and internal growth.

Equity compensation charges increased approximately $1 million in 2007 compared to 2006 primarily as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

The increase in general and administrative expenses for 2006 compared to 2005 was primarily the result of an increase in the indirect costs allocated to the marketing segment in 2006 as the operations have grown through acquisitions and internal growth.

Equity compensation charges increased approximately $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. See Note 10 to our Consolidated Financial Statements.

Maintenance capital. For the years ended December 31, 2007, 2006 and 2005, maintenance capital investment in our marketing segment was approximately $6 million, $3 million and $4 million, respectively.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $180 million for the year ended December 31, 2007, compared to $100 million and $84 million for the years ended December 31, 2006 and 2005, respectively. The increases in 2007 and 2006 related primarily to an increased amount of depreciable assets resulting from our acquisition activities and capital projects. Amortization of debt issue costs was $3 million in 2007, $3 million in 2006 and $3 million in 2005.

Included in depreciation expense for the year ended December 31, 2007 is a net loss of approximately $7 million recognized upon disposition of certain inactive assets compared to a net gain of approximately $2 million for the year ended December 31, 2006 and a net loss of approximately $3 million for the year ended December 31, 2005.

Interest Expense

Interest expense was $162 million for the year ended December 31, 2007, compared to $86 million and $59 million for the years ended December 31, 2006 and 2005, 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 (in millions):

	For the Year Ended December 31,					
	2007		2006		2005	
	Total	% of Total	Total	% of Total	Total	% of Total
Fixed rate senior notes(1)	$ 2,625	95%	$ 1,336	92%	$ 891	87%
Borrowings under our revolving credit facilities(2)	150	5%	118	8%	135	13%
Total	$ 2,775		$ 1,454		$ 1,026	

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

(2) Excludes borrowings under our senior secured hedged inventory facility, allocations of interest related to our inventory stored and capital leases.

The issuance of senior notes and the assumption of Pacific s debt in the fourth quarter of 2006 resulted in an increase in the average amount of longer term and higher cost fixed-rate debt outstanding in 2006 and 2007. The overall higher average debt balances in 2007 and 2006 were primarily related to the portion of our acquisitions that were not financed with equity, coupled with borrowings related to other capital projects. During 2007, 2006 and 2005, the average LIBOR rate was 5.2%, 5.0% and 3.2%, respectively. Our weighted average interest rate, excluding commitment and other fees, was approximately 6.3% in 2007, compared to 6.1% and 5.6% in 2006 and 2005, respectively. The impact of the increased debt balance was an increase in interest expense of $80 million, and the impact of the higher weighted-average interest rate was an increase in interest expense of $4 million. Both of these increases were offset primarily by an increase in capitalized interest of $8 million. The net impact of the items discussed above was an increase in interest expense in 2007 of approximately $76 million.

The higher average debt balance in 2006 as compared to 2005 resulted in additional interest expense of approximately $26 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 6.1% for 2006 compared to 5.6% for 2005. The higher weighted average debt balance rate increased interest expense by approximately $30 million in 2006 compared to 2005. Both of these increases were offset primarily by an increase in capitalized interest of $4 million. The net impact of the items discussed above was an increase in interest expense in 2006 as compared to 2005 of approximately $26 million.

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 $44 million, $49 million and $24 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Interest Income and Other, Net

Interest income and other, net increased by approximately $8 million for the year ended December 31, 2007 compared to the year ended December 31, 2006, primarily due to (i) the recognition of a gain of approximately $4 million upon the sale of a portion of our stock ownership in the NYMEX and (ii) the change in fair value of our interest rate swaps.

Income Tax Expense

Our income tax expense increased by approximately $16 million for the year ended December 31, 2007 compared to the year ended December 31, 2006 primarily due to Canadian taxation on certain flow-through entities and the introduction of the Texas margin tax. See Note 7 to our Consolidated Financial Statements for further discussion.

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 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. We also have expanded our efforts 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. For example, during the first quarter of 2007, we acquired a refined products marketing business and during 2006, we acquired refined products transportation and storage assets as well as an interest in a barge transportation entity. Through PAA/Vulcan s acquisition of ECI in 2005, we acquired an interest in a natural gas storage entity. We are engaged in discussions and negotiations with various parties regarding the acquisition of assets and businesses as described above. Even after we have reached agreement on a purchase price with a potential seller, confirmatory due diligence or negotiations regarding other terms of the acquisition can cause discussions to be terminated. Accordingly, we typically do not announce a transaction until after we have executed a definitive acquisition agreement. Although we expect the acquisitions we make to be accretive in the long term, we can give no assurance that our current or future acquisition efforts will be successful, that any such acquisition will be completed on terms considered favorable to us or that our expectations will ultimately be realized. See Item 1A. Risk Factors.

Longer-Term Outlook

Our longer-term outlook, spanning three to five years or more, 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 and refined products capacity or, alternatively, will result in a reduction, either temporary or permanent, of existing storage capacity by 2009.

The addition of inspection requirements by EPA for storage tanks not subject to DOT s API 653 requirements.

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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. 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 believe we are well-positioned for the future and that the combination of our current baseline activities, our inventory of expansion capital projects and the typical bolt-on acquisitions that augment our annual capital programs underpin our ability to grow our distribution at attractive rates. We also believe that there will be potentially attractive opportunities for consolidation among both public and private midstream entities over the next three years. See Items 1 and 2. Business and Properties Financial Strategy for a discussion of our targeted credit metrics and credit ratings.

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 our business strategy and expertise in hydrocarbon storage will allow us to grow our natural gas storage platform and benefit from these trends.

In the first quarter of 2007 we acquired a refined products marketing business and during 2006, we acquired refined products transportation and storage assets. We believe that the refined products 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 and 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 growing the marketing and distribution business to complement our strategically located assets.

Liquidity and Capital Resources

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At December 31, 2007, we had a working capital deficit of approximately $56 million, approximately $1.0 billion of availability under our committed revolving credit facilities and approximately $0.7 billion of availability under our uncommitted hedged inventory facility. Our working capital decreased approximately $188 million during 2007. See Cash Flow from Operations below, for discussion of the relationship between working capital items and our short-term borrowings. 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 2007, 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 oil 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 (when the price of crude oil for future deliveries is higher than current prices) can have a material impact on our cash flows from operating activities. 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 and we do not rely on borrowings under our credit facilities to pay for the crude oil. Our accounts payable and accounts receivable generally move in tandem 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. In periods during which we build inventory or linefill, regardless of market structure, we may rely on our credit facilities to pay for the inventory or linefill.

The crude oil market was in contango for the first six months of 2007 and for much of 2006 and 2005. In July 2007, the market for crude oil transitioned rapidly to a backwardated market, meaning that the price of crude oil for future deliveries is lower than current prices. The wide contango spreads experienced over the last couple of years, combined with the level of price structure volatility during that time period, has had a favorable impact on our results. If the market remains in the slightly backwardated to transitional structure that has generally prevailed since July 2007, our future results from our marketing segment may be less than those generated during the more favorable contango market conditions that prevailed throughout most of 2005 and 2006 and the first half of 2007.

Our cash flow provided by operating activities in 2007 was $796 million compared to cash used in operating activities of $276 million in 2006. This change reflects cash generated by our recurring operations offset by a decrease in certain working capital items of approximately $190 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. In 2007, the market transitioned and moved into backwardation. As a result, we liquidated most of our crude oil and other product inventories, which led to a positive impact on our cash flow from operating activities. The fluctuations in accounts receivable and other, accounts payable and other current liabilities and short-term debt are primarily related to purchases and sales of crude oil that generally vary proportionately as discussed above.

Our cash flow used in operating activities in 2006 was $276 million compared to cash provided by operating activities of $24 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 primarily 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 purchase and sales of crude oil that generally vary proportionately.

Cash flow provided by operating activities was $24 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 was 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.

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 $2.0 billion of debt or equity securities. At December 31, 2007, we have approximately $0.8 billion of unissued securities remaining available under this registration statement.

Cash used in financing activities was $124 million for 2007 compared to cash provided by financing activities of $1,927 million and $271 million for 2006 and 2005, respectively. Our financing activities primarily relate to funding acquisitions and internal capital projects, and 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 and repayments under our credit facilities.

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

2007			2006			2005		
Units	Net Proceeds(1)		Units	Net Proceeds(1)(2)		Units	Net Proceeds(1)	
6,296,172	$	383	6,163,960	$	306	5,854,000	$	242
			3,720,930		163	575,000		22
			3,504,672		152		$	264
				$	621			

(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 $22 million pertaining to the equity exchange for the Pacific acquisition.

Senior Notes and Credit Facilities. During the three years ended December 31, 2007 we completed the sale of senior unsecured notes as summarized in the table below (in millions).

Year	Description	Maturity	Face Value		Net Proceeds(1)	
2007	No Senior Notes issued	N/A		N/A		N/A
2006	6.125% Senior Notes issued at 99.56% of face value	Jan 2017	$	400	$	398
	6.65% Senior Notes issued at 99.17% of face value	Jan 2037	$	600	$	595
	6.7% Senior Notes issued at 99.82% of face value	May 2036	$	250	$	250
2005	5.25% Senior Notes issued at 99.5% of face value	Jun 2015	$	150	$	149

(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, 2007, we had net working capital and hedged inventory repayments of approximately $54 million. These repayments resulted primarily from sales of crude oil inventory that was stored and subsequently liquidated as we transitioned to backwardated market conditions, partially offset by higher levels of stored LPG inventory. See Cash Flow from Operations above. During 2007, we had no borrowings or repayments on our long-term revolving credit facility compared to net repayments for 2006 and 2005 of $299 million and $143 million, respectively. During 2006, we had net working capital and hedged inventory borrowings of approximately $619 million and during 2005 we had net borrowings of approximately $206 million. For further discussion related to our credit facilities and long-term debt, see Credit Facilities and Long-Term Debt below.

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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, 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				Distribution
	Common	General Partner			per Limited Partner
Year	**Units**	**Incentive**	**2%**	**Total**	**unit**
2007	$ 370	$ 73	$ 8	$ 451	$ 3.28
2006	$ 225	$ 33	$ 5	$ 263	$ 2.87
2005	$ 178	$ 15	$ 4	$ 197	$ 2.58

2008 Capital Expansion Projects. Our 2008 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects	**2008**
Patoka tankage	$ 43
Kerrobert facility	36
Paulsboro tankage	30
Fort Laramie Tank Expansion	22
West Hynes tankage	13
Edmonton tankage and connections	12
Bumstead expansion	10
Pier 400(1)	10
Other Projects(2)	154
Subtotal	$ 330
Maintenance Capital	60
Total	$ 390

(1)

This project requires approval of a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time.

(2) Primarily pipeline connections, upgrades and truck stations as well as new tank construction and refurbishing.

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. We are subject to business and operational risks, however, 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

At December 31, 2007, we had approximately $1.0 billion of available borrowing capacity under our $1.6 billion committed revolving credit facilities and approximately $0.7 billion of availability under our $1.4 billion uncommitted hedged inventory facility. See Note 4 to our Consolidated Financial Statements.

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.

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 senior unsecured revolving 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 5.50 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.

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, 2007 (in millions).

	Total	2008	2009	2010	2011	2012	2013 and Thereafter
Long-term debt and interest payments(1)	$ 5,013	$ 167	$ 339	$ 159	$ 159	$ 355	$ 3,834
Leases(2)	295	47	41	29	20	15	143
Capital expenditure obligations	17	17					
Other long-term liabilities(3)	100	21	26	33	8	1	11
Subtotal	5,425	252	406	221	187	371	3,988
Crude oil, refined products and LPG purchases(4)	8,163	5,490	948	687	546	487	5
Total	$ 13,588	$ 5,742	$ 1,354	$ 908	$ 733	$ 858	$ 3,993

(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, 2007, 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 for trucks used in our gathering activities.

(3) Excludes a non-current liability of approximately $22 million 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, 2007, we had outstanding letters of credit of approximately $153 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. During 2007, we made an additional contribution of $9 million to PAA/Vulcan. Such contribution did not result in an increase to our ownership interest. See Note 8 to our Consolidated Financial Statements.

Distributions. 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. See Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities - Cash Distribution Policy. On February 14, 2008, we paid a cash distribution of $0.85 per unit on all outstanding units. The total distribution paid was approximately $124 million, with approximately $99 million paid to our common unitholders and approximately $25 million paid to our general partner for its general partner interest ($2 million) and incentive distribution interest ($23 million).

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. In conjunction with the formation of PAA/Vulcan and the acquisition of ECI, we 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. 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 remote. 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 are recognized in earnings, and result in greater potential for earnings volatility. This accounting treatment is discussed further in Note 2 to our Consolidated Financial Statements.

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All of our open commodity price risk derivatives at December 31, 2007 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 (in millions):

	Fair Value	Effect of 10% Price Increase
Crude oil:		
Futures contracts	$ (8)	$ 14
Swaps and options contracts	(121)	$ (66)
LPG and other:		
Futures contracts	3	$ 6
Swaps and options contracts	88	$ 34
Total Fair Value	$ (38)	

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 derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. All of our senior notes are fixed rate notes and thus not subject to market risk. All of our variable rate debt at December 31, 2007, approximately $1 billion, is short-term debt and is expected to mature in 2008. The average interest rate of 5.5% is based upon rates in effect at December 31, 2007. 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. See Note 6 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

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, swaps and options. The fair value of these instruments based on current termination values is an unrealized loss of $1 million as of December 31, 2007. See Note 6 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

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

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

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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 the end of the period covered by this report, 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, 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, 2007. 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 2007 that has not previously been reported.

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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 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). GP LLC is the general partner of Plains AAP, L.P. (AAP LP), which is the sole member of PAA GP LLC, our general partner. References to our general partner, as the context requires, include any or all of GP LLC, AAP LP and PAA 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 general partner has in the past exercised such discretion and intends to exercise such discretion in the future.

Our partnership agreement provides that our general partner will manage and operate us and that unitholders, unlike holders of common stock in a corporation, 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. References to our Board of Directors 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 Third 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, unilaterally to 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 voting rights 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 of GP LLC, 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 AAP LP 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 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 for information on how to access or obtain copies of this charter. 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 2007, the amount paid to LEH by Plains Marketing was approximately $0.5 million (net of severance taxes). The board has determined that the transactions with LEH do not compromise Mr. Goyanes independence.

Mr. Arthur L. Smith, a member of our audit committee, is a nominee for director of Pioneer Southwest Energy Partners, L.P. (PSE). PSE is a subsidiary of Pioneer Natural Resources Company (Pioneer). Pioneer and its affiliates (including PSE) own crude oil producing properties, from some of which Plains Marketing buys the production. Mr. Smith will not be an officer of PSE or Pioneer and will not participate in operational decision making. In 2007, the amount paid to Pioneer and its affiliates by Plains Marketing was approximately $309 million. The board has determined that the transactions with PSE and Pioneer do not compromise Mr. Smith s independence.

Mr. J. Taft Symonds, 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 for information on how to access or obtain copies of this charter. 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 2007. 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 for information on how to access or obtain copies of this charter. 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 five regularly scheduled and special meetings, our audit committee had 15 meetings, our compensation committee had one formal meeting and our governance committee had one meeting. 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,

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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. The audit committee reviewed with PricewaterhouseCoopers LLP their judgment as to the quality, not just the acceptability, of the Partnership s accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards.

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

Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2007 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, 2007 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 2007. During 2007, 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, Executive Officers and Other 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. 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 12/31/07)	Position(1)
Greg L. Armstrong*(2)	49	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	50	President and Chief Operating Officer
Phillip D. Kramer*	51	Executive Vice President and Chief Financial Officer
W. David Duckett*	52	President -- PMC (Nova Scotia) Company
Mark F. Shires*	50	Senior Vice President Operations
Alfred A. Lindseth	38	Senior Vice President Technology, Process & Risk Management
Al Swanson*	43	Senior Vice President Finance and Treasurer
Stephen L. Bart	47	Vice President Operations of PMC (Nova Scotia) Company
Ralph R. Cross	52	Vice President Business Development and Transportation Services of PMC (Nova Scotia) Company
A. Patrick Diamond	35	Vice President
Lawrence J. Dreyfuss	53	Vice President, General Counsel Commercial & Litigation and Assistant Secretary
Roger D. Everett	62	Vice President Human Resources
James B. Fryfogle	56	Vice President Refinery Supply
Mark J. Gorman	53	Vice President
M.D. (Mike) Hallahan	47	Vice President Crude Oil of PMC (Nova Scotia) Company
Bill Harradence	54	Vice President Human Resources of PMC (Nova Scotia) Company
Richard (Rick) Henson	53	Vice President Corporate Services of PMC (Nova Scotia) Company
Jim G. Hester	48	Vice President Acquisitions
John Keffer	48	Vice President Terminals
Tim Moore*	50	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	50	Vice President Engineering
John F. Russell	59	Vice President West Coast Projects
Robert Sanford	58	Vice President Lease Supply

Tina L. Val*	38	Vice President Accounting and Chief Accounting Officer

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Name	Age (as of 12/31/07)	Position(1)
Troy E. Valenzuela	46	Vice President Environmental, Health and Safety
John P. vonBerg*	53	Vice President Commercial Activities
David E. Wright	62	Vice President
Ron F. Wunder	39	Vice President LPG of PMC (Nova Scotia) Company
David N. Capobianco(2)	38	Director and Member of Compensation** Committee
Everardo Goyanes	63	Director and Member of Audit** Committee
Gary R. Petersen(2)	61	Director and Member of Compensation Committee
Robert V. Sinnott(2)	58	Director and Member of Compensation Committee
Arthur L. Smith	55	Director and Member of Audit and Governance** Committees
J. Taft Symonds	68	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 GP 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.

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.

Al Swanson has served as Senior Vice President Finance and Treasurer since August 2007. He served as Vice President Finance and Treasurer from August 2005 to August 2007, 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.

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.

A. Patrick Diamond has served as Vice President since August 2007. He previously served as Director, Strategic Planning from July 2005 to August 2007 and as Manager Special Projects from June 2001 to July 2005. In addition, he was Manager Special Projects of Plains Resources from August 1999 to June 2001. Prior to joining Plains Resources, Mr. Diamond served Salomon Smith Barney in its Global Energy Investment Banking Group as an Associate from July 1997 to May 1999 and as a Financial Analyst from July 1994 to June 1997.

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.

Bill Harradence has served as Vice President, Human Resources of PMC (Nova Scotia) Company since October 2007. Prior to joining PMC, Mr. Harradence served as Vice President of Human Resources and Organizational Development at IHS Energy from February 2005 until October 2007, and prior to that he led Human Resources/EH&S at Aquila Canada for four years. Mr. Harradence has over 25 years of human resources experience including Amoco and Safeway.

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 West Coast Projects since August 2007. He served as Vice President Pipeline Operations from July 2004 to August 2007. 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.

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 Commercial Activities since August 2007 and served as Vice President Trading from May 2003 until August 2007. He served as Director of these activities from January 2002 until May 2003. Prior to 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 for 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, the investment arm 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 a director of PAA/Vulcan, ICAT Holdings LLC (an insurance holding company), Silvercrest Asset Management Group LLC and Vulcan MLP LLC. 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. From 1969 to 1982, Mr. Goyanes served in various financial and management capacities at Chase Bank, where his major emphasis was international and corporate finance to large independent and major oil companies. 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 Army Security Agency. Mr. Petersen holds MBA and BBA degress from Texas Tech University.

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 President and Managing Member of Triple Double Advisors, LLC, an investment advisory firm focused on the energy industry. Mr. Smith was Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm) from 1984 to 2007. 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 2007.

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 in the Summary Compensation Table below) compensation at risk. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. We believe our pay-for-performance approach aligns the interests of our 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. 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 meet our objectives. The determination of specific individuals cash bonuses 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. 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 Named 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, we believe 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 of our current domestic Named Executive Officers potentially participate and a formula-based quarterly bonus program in which Messrs. Coiner and vonBerg were eligible to participate during 2007 and 2006. Mr. Duckett participates in a formula-based quarterly and annual bonus program specific to activities managed by our Canadian personnel.

Long-Term Incentive Awards. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. Historically, we have used performance indexed phantom unit grants to encourage and reward timely achievement of targeted distribution levels and align the long-term interests of our Named Executive Officers with those of our unitholders. 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 vesting criteria specified in the grant, a common unit (or cash equivalent). We do 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 our targeted range for distribution growth. To encourage accelerated performance, if we meet certain distribution thresholds prior to meeting the minimum service requirement for vesting, our current Named Executive Officers have the right to receive distributions on phantom units prior to vesting in the underlying common units (referred to as distribution equivalent rights, or DERs).

In 2007, the owners of Plains AAP, L.P. authorized the creation of Class B units of Plains AAP, L.P. and authorized GP LLC s compensation committee to issue grants of Class B units to create additional long-term incentives for our management. The entire economic burden of the Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding. We recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to Partners Capital in our Consolidated Financial Statements. We will not be obligated to reimburse Plains AAP, L.P. for such costs and any distributions made on the Class B units will not reduce the amount of cash available for distribution to our unitholders. Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values.

The Class B units are subject to restrictions on transfer and are not currently entitled to distributions. Class B units generally become earned (entitled to participate in distributions) in 25% increments when the annualized quarterly distributions on our common units equal or exceed $3.50, $3.75, $4.00 and $4.50 per unit. Upon achievement of these performance thresholds (or, in some cases, within six months thereafter), the Class B units will be entitled to their proportionate share of all quarterly cash distributions made by Plains AAP, L.P. in excess of $11 million per quarter (as adjusted for debt service costs and excluding special distributions funded by debt). Assuming all authorized Class B units are issued, the maximum participation would be 8% of the amount in excess of $11 million per quarter, as adjusted.

To encourage retention following achievement of these performance benchmarks, Plains AAP, L.P. retained a call right to purchase any earned Class B units at a discount to fair market value that is exercisable upon the termination of a holder s employment with Plains All American GP LLC and its affiliates for any reason prior to January 1, 2016, other than a termination of employment by the employee for good reason or by Plains All American GP LLC other than for cause (as defined). Upon the occurrence of a change of control (as defined), (i) all earned units will vest (no longer be subject to Plains AAP, L.P. s call right), and (ii) to the extent any of the units are unearned at the time, an incremental 25% of the units originally awarded will vest. All earned Class B units will also vest if they remain outstanding as of January 1, 2016 or Plains AAP, L.P. elects not to timely exercise its call right. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Our General Partner Class B Units of Plains AAP, L.P.

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) and Class B units provide motivation and reward over both the near-term and long-term for achieving performance thresholds necessary for earning and 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 and earned Class B units subject to Plains AAP, L.P. s call right, 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, the long-term (January 2016) vesting profile of the Class B units and, in the case of certain executives directly involved in activities that generate partnership earnings, annual bonuses that are payable over a three-year period. To facilitate Plains All American GP LLC s compensation committee in reviewing and making recommendations, a compensation tally sheet is prepared by Plains All American GP LLC s Chief Executive Officer, or CEO, and General Counsel and provided to the compensation committee.

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 us 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 our Named Executive Officers with our unitholders and positions us to achieve our business goals.

We believe our compensation program has been instrumental to our achievement of stated objectives. Over the five-year period ended December 31, 2007, our annual distribution per common unit has grown at a compound annual rate of 9.2% and the total return realized by our unitholders for that period averaged approximately 24.2%. During this period, we have retained all but one of our Named Executive Officers. As of August 31, 2007, Mr. Coiner (Senior Group Vice President) retired after being with us since our inception. For additional information regarding Mr. Coiner s retirement and related separation agreement, please read Other Compensation Related Matters Former Named Executive Officer below.

Application of Compensation Elements

Salary. We do not make systematic annual adjustments to the salaries of our 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 the date of our initial public offering (or date of employment, if later), Messrs. Armstrong and Pefanis have each received one salary adjustment, Messrs. Coiner and Kramer each received two salary adjustments, Mr. Duckett has received small salary adjustments in line with other Canadian personnel and Mr. vonBerg has received no salary adjustment.

Annual Discretionary Bonuses. Annual discretionary bonuses are determined based on our performance relative to our annual plan forecast and public guidance, our 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 of directors in conjunction with the review and authorization of the annual plan.

At the end of each year, the CEO performs a quantitative and qualitative assessment of our performance relative to our goals. Key quantitative measures include earnings before interest, taxes, depreciation and amortization, excluding items affecting comparability (adjusted EBITDA), relative to established guidance, as well as the growth in the annualized quarterly distribution level per common unit relative to annual growth targets. Our primary performance metric is our ability to generate increasing and sustainable cash distributions to our unitholders. Accordingly, although net income and net income per unit are monitored to highlight inconsistencies with primary performance metrics, as is our market performance relative to our MLP peers and major indices, these metrics are considered secondary performance measures. The CEO s written analysis of our performance examines our 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 the board of directors of Plains All American GP LLC for review and comment. Based on the conclusions set forth in the annual performance review, the CEO submits recommendations to the compensation committee for bonuses to our Named Executive Officers, taking into account the relative contribution of the individual officer. Except as described below for Messrs. Duckett and vonBerg, there are no set formulas for determining the annual discretionary bonus for our Named Executive Officers. Factors considered by the 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. The CEO takes these factors into consideration as well as the relative contributions of each of our 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 of directors for its review and approval. Similarly, the compensation committee assesses the CEO s contribution toward meeting our goals, and recommends a bonus for the CEO it believes to be commensurate with such contribution. In several instances, the CEO (and more recently the President as well) 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. As a result, the current practice is for the CEO to submit to the compensation committee a preliminary draft of bonus recommendations with the amount for the CEO left blank. In the context of discussing and adjusting bonus amounts for other executives set forth in the preliminary draft, the committee and the CEO reach consensus on the appropriate bonus amount for the CEO. The preliminary draft is then revised to include any changes or adjustments, as well as an amount for the CEO, in the formal submittal to the compensation committee for review and recommendation to the board.

U.S. Bonus based on Adjusted EBITDA. Mr. vonBerg and certain other members of our U.S. based senior management team are directly involved in activities that generate partnership earnings. These individuals, along with approximately 110 other employees in our marketing and business development groups participate in a quarterly bonus pool based on adjusted EBITDA, 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 was recommended by Mr. Coiner prior to his retirement effective August 31, 2007 and reviewed, modified and approved by Mr. Pefanis, as appropriate. Following Mr. Coiner s retirement, allocation of quarterly bonus amounts is recommended by Mr. Pefanis and reviewed, modified and approved by Mr. Armstrong, as appropriate. Mr. Pefanis and Mr. Armstrong do not participate in the quarterly bonus. The quarterly bonus amount for Mr. vonBerg is taken into consideration in determining the recommended annual discretionary bonus submitted by the CEO to the compensation committee.

Annual Bonus and Quarterly Bonus based on Adjusted EBITDA (Canada). Substantially all of the personnel employed by PMC (Nova Scotia) Company (including Mr. Duckett) or involved in Canadian operations participate in a bonus pool under a program established at the time of our entry into Canada in 2001 in connection with the CANPET acquisition. The program encompasses a bonus pool consisting of 10% of Adjusted EBITDA for Canadian-based operations (reduced by the carrying cost of inventory in excess of base-level requirements and by the cost of capital associated with growth capital and acquisitions). Participation in the program is recommended by Mr. Duckett and reviewed, adjusted if warranted, and approved by Mr. Pefanis. Mr. Pefanis does not participate in the program. Mr. Duckett receives a quarterly bonus equal to approximately 40% of his participation level for the first three fiscal quarters of the year. He receives an annual bonus consisting of 60% of his participation in the first three quarters and 100% of his participation in the fourth quarter.

Long-Term Incentive Awards. We do not make systematic annual phantom unit awards to our 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 our 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.

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As an additional means of providing longer-term, performance-based officer incentives that require extended periods of employment to realize the full benefit, in 2007 the owners of Plains AAP, L.P. authorized the creation of Class B units of Plains AAP, L.P., which the compensation committee of GP LLC is authorized to administer. See Elements of Compensation Long-Term Incentives. These Class B units are limited to 200,000 authorized units, of which approximately 154,000 were issued as of December 31, 2007 pursuant to individual restricted units agreements between Plains AAP, L.P. and certain members of management. Our Named Executive Officers hold 101,000 of the restricted Class B units. The remaining available Class B units are administered at the discretion of the compensation committee and may be awarded upon advancement, exceptional performance or other change in circumstance of an existing member of management, or upon the addition of a new individual to the management team.

Application in 2007

At the beginning of 2007, we publicly established the following five goals for 2007:

1. Deliver operating and financial performance in line with guidance furnished at the beginning of 2007 on a Form 8-K dated February 22, 2007;

2. Successfully integrate the Pacific transaction and realize targeted synergies;

3. Execute planned slate of internal growth projects;

4. Pursue an average of $200 to $300 million of strategic and accretive acquisitions; and

5. Increase our total distributions paid to unitholders in 2007 by at least 14% over 2006 distributions.

We met or substantially exceeded each of these five goals in 2007. Specifically:

Our adjusted EBITDA exceeded the midpoint of the original guidance for 2007 by approximately 13%;

The integration of Pacific was substantially completed in 2007 and targeted synergy levels were achieved;

We began the year with a $500 million capital program that was expanded during the year to $540 million, of which $525 million was incurred;

We completed four strategic and complementary acquisitions totaling $123 million. Excluding the Pacific acquisition completed in 2006, our three year average acquisition expenditures total approximately $300 million per year; and

We paid approximately $3.28 per unit in distributions during 2007, a 14.4% increase over the $2.87 paid per unit in 2006.

For 2007, the elements of compensation were applied as follows:

Salary. No salary adjustments for NEOs were recommended or made in 2007.

Cash Bonuses. Based on the CEO s annual performance review and the individual performance of each of our current Named Executive Officers, the compensation committee recommended to the board of directors and the board of directors approved the annual bonuses reflected in the Summary Compensation Table and notes thereto. Such amounts take into account the performance relative to each of the five goals established for 2007; 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. Duckett, the aggregate bonus amount represented 40% of his participation level for the first three fiscal quarters and an annual payment consisting of 60% of his participation for the first three quarters and 100% of his participation for the fourth quarter. For Mr. vonBerg, the aggregate bonus amount represented 36% in annual bonus and 64% in quarterly bonus. Relative to bonuses awarded for 2006, the 2007 bonus amounts for current Named Executive Officers are approximately 6% lower to 64% higher. Such adjustments take into account individual contributions to overall performance and recognize that, while both 2006 and 2007 were periods of significant accomplishments, the overperformance during 2006 relative to goals and the significant acquisitions, financings and other related activities completed during that period were generally deserving of greater rewards than the accomplishments during 2007.

Long-Term Incentive Awards. Effective with our November 2006 quarterly distribution, we achieved the highest performance threshold ($3.00 per limited partner unit annualized) contained in substantially all outstanding pre-2006 phantom unit awards. Approximately 31% of these pre-2006 awards met the service-period requirement and vested in May 2007. Vesting of the remaining phantom units under 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 2007 and 2006 related to such awards is reflected on an individual basis in the Summary Compensation Table below. The vesting requirements are described in the footnotes to the Outstanding Equity Awards Table below.

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 2007, the board of directors granted awards with a top performance threshold of $4.00 per common unit, representing a 33% increase over the November 2006 distribution level of $3.00 per unit. These grants are intended to encourage continued growth and fundamental performance that will support future distribution growth. These phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $0.875; one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $1.00; and one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least $0.9375. DERs associated with these units become payable in 25% increments upon achieving quarterly distribution levels of $0.85, $0.90, $0.95 and $1.00 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2014 distribution date will be forfeited. Upon vesting, the phantom units are payable on a one-for-one basis in common units (or cash equivalent). The 2007 awards included grants to our Named Executive Officers as follows: Mr. Armstrong, 180,000; Mr. Pefanis, 120,000; Mr. Kramer, 60,000; Mr. Duckett, 75,000, Mr. vonBerg, 54,000 and Mr. Coiner, 90,000 (as discussed below, Mr. Coiner s grants were cancelled in August 2007 in connection with his retirement). The number of phantom units awarded to our Named Executive Officers represents approximately 60% of the awards granted to such individuals in 2005.

During 2007, Class B units were issued to our Named Executive Officers as follows: Mr. Armstrong, 40,000; Mr. Pefanis, 30,000; Mr. Duckett, 17,000; and Mr. vonBerg, 14,000.

Other Compensation Related Matters

Equity Ownership in PAA. As of December 31, 2007, our current Named Executive Officers collectively owned substantial equity in the Partnership. Although we encourage our Named Executive Officers to retain ownership in the Partnership, we do not have a policy requiring maintenance of a specified equity ownership level. Our policies prohibit our Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership. In the aggregate, as of December 31, 2007, our current Named Executive Officers beneficially owned, in the aggregate, approximately 724,000 of our common units (excluding any unvested equity awards), an approximately 3% indirect ownership interest in our general partner and IDRs, and 101,000 Class B units of Plains AAP, L.P. Based on the market price of our common units at December 31, 2007 and an implied valuation for their collective general partner and IDR interests using similar valuation metrics, the value of the equity ownership of these individuals was significantly greater than the combined aggregate salaries and bonuses for 2007.

Recovery of Prior Awards. Except as provided by applicable laws and regulations, we do 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, we are a limited partnership and do not meet the definition of a corporation under Section 162(m).

Change in Control Triggers. The employment agreements for Messrs. Armstrong and Pefanis, the long-term incentive plan grants to our Named Executive Officers, and the Class B restricted units agreements 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 Plains All American GP LLC). 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 sale transaction in August 2005 that would have constituted a change in control. See Potential Payments upon Termination or Change-in-Control and Employment Agreements.

Former Named Executive Officer. As of August 31, 2007, Mr. Coiner retired as Senior Group Vice President. In connection with Mr. Coiner s retirement, we and Mr. Coiner entered into a separation agreement. Terms of the agreement provided for cancellation of substantially all outstanding equity awards (including awards for which performance thresholds had been achieved, but excluding from cancellation certain options granted in 2001 for which all performance and time vesting requirements have been satisfied) and payment to Mr. Coiner of a lump sum amount of approximately $8.7 million in satisfaction of our obligations with respect to the cancelled equity awards, deferred and quarterly bonus amounts for prior and current periods, accrued vacation and other related obligations. The agreement also includes (i) a provision pursuant to which Mr. Coiner will remain our consultant through the first quarter of 2009 and for such services will receive a quarterly fee of $500,000, (ii) a general release by Mr. Coiner of any claims against us and (iii) Mr. Coiner s agreement that his Confidential Information and Non-Solicitation Agreement dated November 23, 1998 will remain in full force and effect until March 31, 2010. In addition to the amounts noted above, we will pay the premiums for COBRA coverage for a period of up to 18 months.

Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer, Chief Financial Officer, the three other most highly compensated executive officers in 2007 and one former executive officer who retired during the fiscal year (our Named Executive Officers). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation (excluding the costs of the obligations represented by the Class B units).

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong	2007	375,000	3,400,000	5,660,135	14,430	9,449,565
Chairman and CEO	2006	375,000	3,750,000	5,184,222	15,930	9,325,152
Harry N. Pefanis	2007	300,000	3,200,000	3,854,810	14,430	7,369,240
President and Chief Operating Officer	2006	300,000	3,400,000	3,456,148	15,930	7,172,078
Phillip D. Kramer	2007	250,000	850,000	1,651,155	14,430	2,765,585
Executive Vice President and Chief Financial Officer	2006	250,000	1,000,000	1,876,043	15,930	3,141,973
W. David Duckett(3)	2007	266,960	3,370,984(3)	2,228,516	93,501	5,959,961
President PMC (Nova Scotia) Company	2006	251,302	2,063,109(3)	2,203,918	63,349	4,581,678
John P. vonBerg	2007	200,000	2,765,000(4)	1,780,055	14,244	4,759,299
Vice President Commercial Activities	2006	200,000	2,934,700(4)	1,575,530	15,744	4,725,974
George R. Coiner	2007	166,667	689,000(5)	520,711(6)	7,092,518(7)	8,468,896
Former Senior Group Vice President	2006	250,000	3,390,100(5)	2,616,477	15,930	6,272,507

(1) Dollar amounts represent the compensation expense recognized in each fiscal period with respect to outstanding phantom unit grants under our LTIP and outstanding Class B units, whether or not granted during the applicable period. See Note 10 to our Consolidated Financial Statements for a discussion of the assumptions made in determining these amounts. For the 2006 period, as of the end of the year substantially all of the performance thresholds for earning the phantom units represented by the amounts indicated had been met; however, none of the amounts included in the 2006 period were vested as of such date as they contain ongoing service requirements and, subject to meeting those requirements, vested or will vest in various increments in 2007, 2008, 2009 and 2010. For the 2007 period, as of the end of the year all of the performance thresholds for earning the phantom units granted prior to fiscal year 2007 had been met; however, as described above, only a portion of the service period requirements were satisfied during fiscal year 2007. For phantom units granted in 2007, the performance threshold for the first one-third vesting was deemed probable of occurrence as of the end of 2007; however, the earliest vesting of such units would be in 2011. For a description of the vesting terms of long-term incentive grants in 2007, see footnotes 1 and 2 to the Grants of Plan-Based Awards Table. Amounts in this column also include compensation expense recorded on our financial statements associated with the Class B units. The entire economic burden of the Class B units, which are equity classified, is borne solely by Plains

AAP, L.P. and does not impact our cash or units outstanding. We recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to Partners Capital in our Consolidated Financial Statements. Recognition of expense for all performance-based long-term incentives is required once an assessment has been made that the likelihood of achievement of a performance threshold is probable. For the Class B units, such expense amount is based on the fair market value of the associated interest at the date of grant, proportionate to the relevant service period incurred through the end of the period reported and any balance will be amortized over the remaining service period through the achievement of such performance threshold. The analysis is the same for LTIPs, except that the expense amount is based on the market value of an underlying common unit on the last business day of the reporting period.

(2) Plains All American GP LLC matches 100% of employees contributions to its 401(k) plan in cash, subject to certain limitations in the plan. All Other Compensation for each of Messrs. Armstrong, Pefanis, Kramer, vonBerg and Coiner includes $13,500 in such contributions for 2007. The remaining amount for each represents premium payments on behalf of such Named Executive Officer for group term life insurance. All Other Compensation for Mr. Duckett includes, for 2007, employer contributions to the PMC (Nova Scotia) Company savings plan of $34,705, group term life insurance premiums of $17,159, automobile lease payments of $39,553 and club dues.

(3) Salary, bonus and all other compensation amounts for Mr. Duckett are presented in U.S. dollar equivalent, based on the exchange rates in effect on the dates payments were made or approved (in the case of his annual bonus). Mr. Duckett participates in a bonus pool under a program established at the time of our entry into Canada in 2001. Bonus amounts include quarterly bonuses aggregating $1,348,528 and $838,544 and annual bonuses of $2,022,456 and $1,224,565 for 2007 and 2006, respectively. An amount equal to 67% of Mr. Duckett s 2007 bonus will be paid in 2009.

(4) Includes quarterly bonuses aggregating $1,765,000 and $1,834,700 and annual bonuses of $1,000,000 and $1,100,000 in 2007 and 2006, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

(5) Includes quarterly bonuses aggregating $689,000 and $2,040,100 in 2007 and 2006, respectively, and an annual bonus of $1,350,000 in 2006. The annual bonus was initially payable 60% at the time of award and 20% in each of the two succeeding years but has been satisfied through the lump sum payment under Mr. Coiner s separation agreement. See footnote 7 below.

(6) Amount represents compensation expense recognized in 2007 associated with the LTIP grant that was paid in cash in May 2007.

(7) As of August 31, 2007, Mr. Coiner retired as Senior Group Vice President. In connection with Mr. Coiner s retirement, we and Mr. Coiner entered into a separation agreement. Terms of the agreement provide for cancellation of outstanding equity awards (including awards for which performance thresholds have been achieved, but excluding from cancellation certain options granted in 2001 for which all performance and time vesting requirements have been satisfied) and payment to Mr. Coiner of a lump sum amount of approximately $8.7 million in satisfaction of our obligations with respect to the cancelled equity awards, deferred and quarterly bonus amounts for prior and current periods, accrued vacation and other related obligations. The agreement also includes (i) a provision pursuant to which Mr. Coiner will remain our consultant through the first quarter of 2009 and for such services will receive a quarterly fee of $500,000, (ii) a general release by Mr. Coiner of any claims against us and (iii) Mr. Coiner s agreement that his Confidential Information and Non-Solicitation Agreement dated November 23, 1998 will remain in full force and effect until March 31, 2010. In addition to the amounts noted above, we will pay the premiums for COBRA coverage for a period of up to 18 months. The amount reflected in this column (x) excludes amounts attributable to compensation expense recognized in prior periods associated with deferred bonuses (approximately $1.6 million) or with LTIP grants (approximately $2.2 million) and (y) includes any amounts attributable to compensation expense recognized in 2007 associated with the quarterly consulting payments (approximately $2.2 million), as well as the 401(k) and group term life payments described in footnote 2 above.

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Grants of Plan-Based Awards Table

The following table sets forth summary information regarding all grants of plan-based awards made to our Named Executive Officers during the fiscal year ended December 31, 2007.

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number Of Shares Of Stock or Units	All Other Option Awards: Number Of Securities Underlying Options	Exercise or Base Price Of Option Awards	Grant Date Fair Value Of Stock and Option Awards
Name	Grant Date	Approval Date	Threshold ($)	Target ($)	Maximum ($)	Threshold ($)	Target ($)	Maximum ($)	(#)	(#)	($/Sh)	($)
Greg L. Armstrong	2/22/07	2/22/07							180,000(1)			8,775,000(1)
	8/29/07	8/29/07							40,000(2)			8,758,000(2)
Harry N. Pefanis	2/22/07	2/22/07							120,000(1)			5,850,000(1)
	8/29/07	8/29/07							30,000(2)			6,568,500(2)
Phillip D. Kramer	2/22/07	2/22/07							60,000(1)			2,925,000(1)
W. David Duckett	2/22/07	2/22/07							75,000(1)			3,656,250(1)
	12/11/07	11/28/07							17,000(2)			3,722,150(2)
John D. vonBerg	2/22/07	2/22/07							54,000(1)			2,632,500(1)
	8/29/07	8/29/07							14,000(2)			3,065,300(2)
George R. Coiner	2/22/07	2/22/07							90,000(1)			N/A(3)

(1) These phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $0.875; one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $1.00; and one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least $0.9375. DERs associated with these units become payable in 25% increments upon achieving quarterly distribution levels of $0.85, $0.90, $0.95 and $1.00 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2014 distribution date will expire. The amount shown has been computed in accordance with SFAS 123(R) and reflects the grant-date per-unit closing price ($54.94) of the common units underlying the phantom units, discounted for the period during which DERs

would not be paid, but without discount for performance thresholds or service periods.

(2) These Class B units of Plains AAP, L.P. were authorized by the owners of our general partner to create long-term incentives for our management. Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values, but does not represent an interest in the capital of Plains AAP, L.P. on the grant date of the Class B units. Class B units become earned (entitled to participate in distributions) in 25% increments when the annualized quarterly distributions on our common units equal or exceed $3.50, $3.75, $4.00 and $4.50 per unit. Upon achievement of these performance thresholds (or, in some cases, six months thereafter), the Class B units will be entitled to their proportionate share of all quarterly cash distributions made by Plains AAP, L.P. in excess of $11 million per quarter, as adjusted for debt service costs and excluding any distributions funded by debt. Assuming all authorized Class B units are issued, the maximum participation would be 8% of the amount in excess of $11 million per quarter, as adjusted. Plains AAP, L.P. retained a call right to purchase any earned Class B units at a discount to fair market value, which call right will be exercisable upon the termination of a holder s employment with Plains All American GP LLC and its affiliates for any reason prior to January 1, 2016 other than a termination of employment by the holder of Class B units for good reason or by Plains All American GP LLC other than for cause (as defined). Upon the occurrence of a change of control (as defined), (i) all earned units will vest (no longer be subject to Plains AAP, L.P. s call right), and (ii) to the extent of any of the units are unearned at the time, an incremental 25% of the units originally awarded will vest. All earned Class B units will also vest if they remain outstanding as of January 1, 2016 or Plains AAP, L.P. elects not to timely exercise its call right. The amount shown reflects the grant date fair value computed in accordance with SFAS 123(R). For additional information regarding the Class B Units, please read Item 13. Certain Relationships and Related

Transactions, and Director Independence Transactions with Related Persons Our General Partner Class B Units of Plains AAP, L.P.

(3) This award was cancelled in connection with Mr. Coiner s retirement. See footnote 7 to the Summary Compensation Table.

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

A discussion of 2007 salaries, bonuses and long-term incentive awards 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.

2007 Salary As discussed in this Item 11, we do not make systematic annual adjustments to the salaries of our Named Executive Officers. Accordingly, no salary adjustments were made for any of our Named Executive Officers in 2007.

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 we use salary and bonus 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 that the board of directors 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 we use salary and bonus 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.

In connection with Mr. vonBerg s employment in January 2002, Plains All American GP LLC and Mr. vonBerg entered into a letter agreement setting forth the terms of his employment. The letter agreement expired in accordance with its terms in January 2007. Mr. vonBerg also entered into an ancillary agreement which provides that, in the event of his termination, for a period of one year 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.

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Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2007 with respect to our Named Executive Officers:

Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1)
Greg L. Armstrong	37,500(2)			$ 8.93	6/07/2011				
						210,000(3)	10,920,000		
								180,000(4)	9,360,000
								40,000(5)	8,758,000
Harry N. Pefanis	27,500(2)			$ 8.93	6/07/2011				
						140,000(3)	7,280,000		
								120,000(4)	6,240,000
								30,000(5)	6,568,500
Phillip D. Kramer	22,500(2)			$ 8.93	6/07/2011				
						60,000(6)	3,120,000		
								60,000(4)	3,120,000
W. David Duckett						45,000(6)	2,340,000		
						50,000(7)	2,600,000		
								75,000(4)	3,900,000
								17,000(5)	3,722,150
John P. vonBerg						24,000(6)	1,248,000		
						50,000(7)	2,600,000		
								54,000(4)	2,808,000

				14,000(5)	3,065,300
George R. Coiner	21,250(2)	$ 8.93	6/07/2011		

(1) Market value of phantom units reported in these columns is calculated by multiplying the closing market price ($52.00) of our common units at December 31, 2007 (the last trading day of the fiscal year) by the number of units. No discount is applied for remaining performance threshold or service period requirements. The Class B units are valued based on the grant date fair value computed in accordance with SFAS 123(R). A portion of the value reflected in these columns 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 partner 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) All applicable performance (distribution) thresholds have been met, and these phantom units will vest as follows: approximately 43% will vest upon the May 2009 distribution date and approximately 57% will vest upon the May 2010 distribution date. DERs associated with these phantom units have vested.

(4) These phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $0.875; one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $1.00; and one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least $0.9375. DERs associated with these units become payable in 25% increments upon achieving quarterly distribution levels of $0.85, $0.90, $0.95 and $1.00 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2014 distribution date will expire.

(5) Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values, but does not represent an interest in the capital of Plains AAP, L.P. on the applicable grant date of the Class B units. For additional information regarding the

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Class B Units, please read Compensation Discussion and Analysis Elements of Compensation Long-Term Incentives.

(6) All applicable performance (distribution) thresholds have been met, and these phantom units will vest as follows: 50% will vest upon the May 2009 distribution date and 50% will vest upon the May 2010 distribution date. DERs associated with these phantom units have vested.

(7) All applicable performance (distribution) thresholds have been met, and these phantom units will vest in equal one-third increments as follows: one-third will vest upon each of the May 2008, May 2009 and May 2010 distribution dates. DERs associated with these units have vested.

Option Exercises and Units Vested

	Option Awards		Unit Awards	
Name	**Number of Units Acquired on Exercise (#)**	**Value Realized on Exercise ($)**	**Number of Units Acquired on Vesting (#)(1)**	**Value Realized on Vesting ($)(1)**
Greg L. Armstrong			90,000	5,532,300
Harry N. Pefanis			60,000	3,688,200
Phillip D. Kramer			40,000	2,458,800
W. David Duckett			30,000	1,844,100
John P. vonBerg			16,000	983,520
George R. Coiner			(2)	1,888,384

(1) Represents the gross number and value of phantom units that vested during the year ended December 31, 2007. The actual number of units delivered was net of income tax withholding. The units in this table represent all unit awards of our Named Executive Officers that vested during 2007. Consistent with the terms of our 2005 Long-Term Incentive Plan, the value realized upon vesting (other than as described in footnote 2, below) is computed by multiplying the closing market price ($61.47) of our common units on May 14, 2007 (the date preceding the vesting date) by the number of units that vested.

(2) In May 2007, Mr. Coiner received a cash payment of $1,888,384, representing the value equivalent of 32,000 units, calculated using the five-day closing average price prior to the then most recent ex-dividend date. All remaining phantom units granted to Mr. Coiner were cancelled in connection with his separation agreement.

Pension Benefits

We sponsor a 401(k) plan that is available to all U.S. employees, but we do not maintain a pension or defined benefit program.

Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans

We do not have a nonqualified deferred compensation plan or program for our officers or employees.

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Potential Payments upon Termination or Change-in-Control

The following table sets forth potential amounts payable to the Named Executive Officers upon termination of employment under various circumstances, and as if terminated on December 31, 2007.

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	8,250,000(1)	8,250,000(1)	8,250,000(1)	8,250,000(1)	12,375,000(2)
Equity Compensation	14,008,800(3)	14,008,800(3)	20,280,000(4)	20,280,000(4)	20,280,000(5)
Health Benefits	N/A	36,210(6)	36,210(6)	36,210(6)	36,210(6)
Tax Gross-up	N/A	N/A	N/A	N/A	1,914,888(7)
Class B Units	N/A	N/A	N/A	N/A	2,772,400(8)
Total	22,258,800	22,295,010	28,566,210	28,566,210	37,378,498
Harry N. Pefanis					
Salary and Bonus	7,400,000(1)	7,400,000(1)	7,400,000(1)	7,400,000(1)	11,100,000(2)
Equity Compensation	9,339,200(3)	9,339,200(3)	13,520,000(4)	13,520,000(4)	13,520,000(5)
Health Benefits	N/A	36,210(6)	36,210(6)	36,210(6)	36,210(6)
Tax Gross-up	N/A	N/A	N/A	N/A	1,778,804(7)
Class B Units	N/A	N/A	N/A	N/A	2,079,300(8)
Total	16,739,200	16,775,410	20,956,210	20,956,210	28,514,314
Phillip D. Kramer(9)					
Equity Compensation	4,149,600(3)	4,149,600(3)	3,120,000(4)	N/A	6,420,000(5)
Total	4,149,600	4,149,600	3,120,000	N/A	6,420,000
W. David Duckett(9)					
Equity Compensation	6,227,000(3)	6,227,000(3)	4,940,000(4)	N/A	8,840,000(5)
Class B Units	N/A	N/A	N/A	N/A	1,178,270(8)
Total	6,227,000	6,227,000	4,940,000	N/A	10,018,270
John P. vonBerg(9)					
Equity Compensation	4,774,640(3)	4,774,640(3)	3,848,000(4)	N/A	6,656,000(5)
Class B Units	N/A	N/A	N/A	N/A	970,340(8)
Total	4,774,640	4,774,640	3,848,000	N/A	7,626,340
George R. Coiner (10)					
Total	N/A	N/A	N/A	N/A	N/A

(1)

The employment agreements between Plains All American GP LLC and Messrs. Armstrong and Pefanis provide that if (i) their employment with Plains All American GP LLC is terminated as a result of their death, (ii) they terminate their employment with Plains All American GP LLC (a) because of a disability (as defined below) or (b) for good reason (as defined below), or (iii) Plains All American GP LLC 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 31, 2007, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $3,750,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $3,400,000 for Mr. Pefanis.

The employment agreements between Plains All American GP LLC 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 Plains All American GP LLC 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 Plains All American GP LLC or otherwise likely to result in no material injury to Plains All American GP LLC. 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 Plains All American GP LLC 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. If Mr. Armstrong or Mr. Pefanis were terminated for cause, Plains All American GP LLC would be obligated to pay base salary through the date of termination, with no other payment obligations triggered by the termination under the employment agreement or other employment arrangement.

The employment agreements between Plains All American GP LLC and Messrs. Armstrong and Pefanis define good reason as the occurrence of any of the following circumstances: (i) removal by Plains All American GP LLC 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 Plains All American GP LLC, 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 Plains All American GP LLC 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 Plains All American GP LLC 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 Plains All American GP LLC.

(2) Pursuant to their employment agreements, if Messrs. Armstrong and Pefanis terminate their employment with Plains All American GP LLC 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 31, 2007, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $3,750,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $3,400,000 for Mr. Pefanis.

For this purpose a change in control is currently defined in their employment agreements to mean (i) the acquisition by a person or group (other than Plains Resources Inc. or a wholly owned subsidiary thereof) of beneficial ownership, directly or indirectly, of 50% or more of the membership interest of Plains All American GP LLC or (ii) the existing owners of the membership interests of Plains All American GP LLC ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of Plains All American GP LLC.

In August 2005, Vulcan Energy increased its interest in Plains All American GP LLC 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 Plains All American GP LLC 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 Plains All American 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 a change of control would be deemed to have occurred.

(3) The letters evidencing the 2005 and 2007 phantom unit grants to our 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 or expire as provided in Footnotes 3 and 4 to the Outstanding Equity Awards at Fiscal Year-End table. For this purpose disability means a physical or mental infirmity that impairs the ability substantially 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 31, 2007. As a result, all phantom units and the associated DERs of our Named Executive Officers would have become nonforfeitable effective as of December 31, 2007, and vested at the time(s) described in the footnotes to the Outstanding Equity Awards at Fiscal Year-End table. For the 2007 grants, any units not vested by May 2014 would expire. The dollar value given assumes that all performance thresholds will be timely achieved if deemed probable of occurrence as of December 31, 2007, and is based on the market value on December 31, 2007 ($52.00 per unit) without discount for service period. If the performance thresholds were not deemed probable of occurrence as of December 31, 2007, the units are assumed to expire unvested in May 2014. At December 31, 2007, an annualized distribution level of $3.50 was deemed probable of occurrence. All outstanding 2005 grants and one third of the 2007 grants were assumed to eventually vest as a result.

(4) Pursuant to the 2005 and 2007 phantom unit grants to our 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 phantom units and associated DERs (regardless of vesting) then outstanding under their respective 2005 and 2007 phantom unit grants would automatically be forfeited as of the date of termination; provided, however, that if Plains All American GP LLC 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 our Named Executive Officers were terminated without cause on December 31, 2007. As a result, all of the outstanding 2005 phantom unit grants held by our Named Executive Officers would be deemed nonforfeitable and would vest on the February 2008 distribution date. All of the outstanding 2007 phantom unit grants would be forfeited. The dollar value given is based on the market value on December 31, 2007 of $52.00 per unit, without discount for service period. In addition to the foregoing, under Canadian law Mr. Duckett could have a claim for additional payment if inadequate notice were given for a termination without cause.

Under the waiver signed in 2005 by Mr. Armstrong and Mr. Pefanis (see footnote 2 above), upon a termination of employment by the company without cause or by the executive for good reason (in each case as defined in the relevant employment agreement) all of the executive s outstanding awards under the 1998 and 2005 Long-Term Incentive Plans would immediately vest.

(5) The 2005 and 2007 phantom unit grants to our Named Executive Officers provide that in the event of a change of status (as defined below), all of the then outstanding phantom units and associated DERs will be deemed 100% nonforfeitable, and such phantom units and associated DERS will vest in full (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) upon the next distribution date. Assuming the change in status occurred on December 31, 2007, all outstanding phantom units and the associated DERs would have become nonforfeitable as of December 31, 2007, and such phantom units and tandem DERs would vest on the February 2008 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 Plains All American GP LLC 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) Plains All American 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 our partnership or Plains All American GP LLC to any person and/or its affiliates, other than to us or Plains All American GP LLC, including any employee benefit plan thereof; (iii) the consolidation, reorganization, merger, or any other similar transaction involving (A) a person other than us or Plains All American GP LLC and (B) us, Plains All American GP LLC or both; (iv) the persons who own membership interests in Plains All American GP LLC ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of Plains All American 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 Plains All American GP LLC. With respect to the lattermost event, the 2005 grant letter makes an exception for any existing member of Plains All American 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 Mr. vonBerg and Mr. Duckett). Notwithstanding the definition of change of control, no change of control is deemed to have occurred in connection with a restructuring or reorganization related to the securitization and sale to the public of direct or indirect equity interests in the general partner if (x) Plains All American GP LLC retains direct or indirect control over the general partner and (y) the current members of GP LLC continue to own more than 50% of the member interest in Plains All American GP LLC.

The term cause means (i) the failure to perform a job function in accordance with standards described in writing, or (ii) the violation of Plains All American GP LLC 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 Plains All American GP LLC, 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 Plains All American GP LLC to its executive officers generally. The amounts provided in the table assume a termination date of December 31, 2007.

(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 31, 2007.

(8) Pursuant to the Class B Restricted Units Agreements, upon the occurrence of a Change in Control, any earned units become vested units and, to the extent any units remain unearned, an incremental 25% of the number of units originally granted becomes vested. As of December 31, 2007, none of the units were earned. Assuming a change in control on such date, 25% of the units would become vested. The value of such units as reflected in the table is derived in accordance with SFAS 123(R). Change in Control means the determination by the Board that one of the following events has occurred:

(a) prior to a GP IPO: (i) Plains All American GP LLC ceases to retain direct or indirect control over the Partnership; (ii) the owners of Plains All American GP LLC and their affiliates (the Owner Affiliates) cease to own directly or indirectly at least 50% of its member interest; (iii) a person or group (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act) becomes after the Grant Date the beneficial owner (as defined in Rules 13(d)-3 and 13(d)-5 under the Exchange Act), directly or indirectly, of more than 50% of the member interest of Plains All American GP LLC; or (iv) a transfer, sale, exchange or other disposition in a single transaction or series of transactions (whether by merger or otherwise) of all or substantially all of the assets of the Plains AAP, L.P. or the Partnership to one or more persons who are not Affiliates of Plains AAP, L.P., other than a transaction in which the Owner Affiliates become the beneficial owners , directly or indirectly, of more than 50% of the voting power of such person or persons immediately following such transaction;

provided, however, that no Change of Control shall be deemed to have occurred in connection with a restructuring or reorganization related to a GP IPO if the Owner Affiliates retain direct or indirect control over the IPO Entity and Plains All American GP LLC; and

(b) from and after the consummation of a GP IPO: (i) the Owner Affiliates cease to retain direct or indirect control over the IPO Entity or Plains AAP, L.P.; (ii) (x) a person or group other than the Owner Affiliates becomes the beneficial owner directly or indirectly of 25% or more of the member interest in the general partner of the IPO Entity, and (y) the member interest beneficially owned by such person or group

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exceeds the aggregate member interest in the general partner of the IPO Entity beneficially owned, directly or indirectly, by the Owner Affiliates; or (iii) a direct or indirect transfer, sale, exchange or other disposition in a single transaction or series of transactions (whether by merger or otherwise) of all or substantially all of the assets of the IPO Entity or the Partnership to one or more persons who are not affiliates of the IPO Entity (third party or parties), other than a transaction in which the Owner Affiliates continue to beneficially own, directly or indirectly, more than 50% of the voting power of such third party or parties immediately following such transaction.

(9) If Messrs. Kramer, Duckett or vonBerg were terminated for cause, Plains All American GP LLC would be obligated to pay base salary through the date of termination, with no other payment obligation triggered by the termination under any employment arrangement.

(10) As of August 31, 2007, Mr. Coiner retired as Senior Group Vice President. For a description of the separation agreement we entered into with Mr. Coiner, see footnote 7 to the Summary Compensation Table.

Confidentiality, Non-Compete and Non-Solicitation Arrangements

Pursuant to his employment agreement, Mr. Armstrong has agreed to maintain the confidentiality of PAA 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. Pursuant to his separation agreement, Mr. Coiner has agreed to maintain confidentiality and not to solicit customers or employees until March 31, 2010. Pursuant to his employment agreement, 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 paid to Plain All American GP LLC s non-employee directors in 2007:

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation ($)	Total ($)
David N. Capobianco(2)	47,000	79,318					126,318
Everardo Goyanes	75,000	197,216					272,216
Gary R. Petersen(2)	45,000	79,318					124,318
Robert V. Sinnott	45,000	79,318					124,318
Arthur L. Smith	62,000	197,216					259,216
J. Taft Symonds	60,000	197,216					257,216

(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. 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. Commencing in 2008, such cash payment will be based on the unit value on the previous year s vesting date. Each audit committee member (currently Messrs. Goyanes, Smith and Symonds) has 10,000 units outstanding and Mr. Sinnott has 5,000 units outstanding. These awards vest annually in 25% increments. 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 and 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 2007. 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 Plains All American GP LLC who is not an employee of Plains All American GP LLC 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 the audit committee each have outstanding a grant of 10,000 units (vesting 2,500 units per year). Mr. Sinnott has outstanding 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 Plains All American GP LLC member that appointed him as a director. Such affiliates receive an annual cash payment based on the value of the annual vesting of Mr. Sinnott s award.

All LTIP awards held by a director 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 limited liability company agreement of Plains All American GP LLC, and currently including Messrs. Goyanes, Smith and Symonds), the awards 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 of directors or is not reelected to the board of directors, 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 direct and indirect costs of services provided to us, incurred on our behalf, including the costs of employee, officer and director compensation and benefits allocable to us, as well as all other expenses necessary or appropriate to the conduct of our business, allocable to us. We record these costs on the accrual basis in the period in which our general partner incurs them. 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.

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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, 2008.

Name of Beneficial Owner	Common Units	Percentage of Common Units
Paul G. Allen	14,386,074(1)	12.4%(2)
Vulcan Energy Corporation	12,390,120(3)	10.7%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	9,211,946(4)	7.9%
Greg L. Armstrong	287,607(5)(6)(7)	(8)
Harry N. Pefanis	184,697(6)(7)	(8)
Phillip D. Kramer	113,790(6)(7)	(8)
George R. Coiner	58,126(7)(9)	(8)
Dave Duckett	137,841(6)	(8)
John P. vonBerg	(6)	(8)
David N. Capobianco	(10)	(8)
Everardo Goyanes	13,700	(8)
Gary R. Petersen	5,200(11)	(8)
Robert V. Sinnott	16,500(12)	(8)
Arthur L. Smith	15,850	(8)
J. Taft Symonds	25,000	(8)
All directors and executive officers as a group (15 persons)	883,398(7)(13)	(8)

(1) Mr. Allen owns approximately 80% 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.

(2) 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 13% 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.

(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 8,965,781 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 246,165 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 164,484 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 Item 11. Executive Compensation 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 (excluding Mr. Coiner): 105,000.

(8) Less than one percent.

(9) Unit information for Mr. Coiner is based on his last Form 4 filed in connection with his retirement.

(10) 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.

(11) Pursuant to the GP LLC Agreement, Mr. Petersen has been designated as 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.

(12) Pursuant to the GP LLC Agreement, Mr. Sinnott has been designated as 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 the interests owned by KAFU Holdings, L.P. or its affiliates, other than through his 4.9% direct and indirect limited partner interest in KAFU Holdings, L.P. Mr. Sinnott has a non-controlling ownership interest in KACALP, which is the general partner of KAFU Holdings, L.P. KACALP is entitled to a percentage of the profits earned by the funds invested in KAFU Holdings, L.P. The address for KAFU Holdings, L.P. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(13) Beneficial ownership of common units by directors and executive officers as a group excludes units held by Mr. Coiner. As of February 20, 2008, no units were pledged by directors or Named Executive Officers. Certain of the directors and Named Executive Officers hold units in marginable broker s accounts, but none of the units were margined as of February 20, 2008.

Beneficial Ownership of General Partner Interest

Plains AAP, L.P. owns all of our incentive distribution rights and, through its 100% member interest in PAA GP LLC, our 2% general partner interest. 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, L.P.(1)
Paul G. Allen(2) 505 Fifth Avenue S, Suite 900 Seattle, WA 98104	54.3%
Vulcan Energy Corporation(3) c/o Plains All American GP LLC 333 Clay Street, Suite 1600 Houston, TX 77002	54.3%
KAFU Holdings, L.P.(4) 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	20.3%
E-Holdings III, L.P.(5) 1100 Louisiana, Suite 3150 Houston, TX 77002	9.0%
E-Holdings V, L.P.(5) 1100 Louisiana, Suite 3150 Houston, TX 77002	2.1%
PAA Management, L.P.(6) 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) Plains AAP, L.P. owns a 100% member interest in PAA GP LLC, which owns our 2% general partner interest. Plains AAP, L.P. has pledged its member interest, as well as its interest in our incentive distribution rights, as security for its obligations under the Credit Agreement dated as of January 3, 2008 among Plains AAP, L.P., Citibank, N.A. and the lenders party thereto (the Plains AAP Credit Agreement). A default by Plains AAP, L.P. under the Plains AAP Credit Agreement could result in a change in control of our general partner. Certain

members of management own a profits interest in Plains AAP, L.P. in the form of Class B units. See Item 11. Executive Compensation Grants of Plan Based Awards Table.

(2) Mr. Allen owns approximately 80% 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.

(3) 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.

(4) Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. other than through his 4.9% direct and indirect limited partner interest in KAFU Holdings, L.P. Mr. Sinnott has a non-controlling ownership interest in KACALP, which is the general partner of KAFU Holdings, L.P. KACALP is entitled to a percentage of the profits earned by the funds invested in KAFU Holdings, L.P.

(5) 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.

(6) PAA Management, L.P. is owned entirely by certain current and former members of senior management, including Messrs. Armstrong (approximately 25%), Pefanis (approximately 14%), Kramer (approximately 9%), Coiner (approximately 9%), Duckett (approximately 4%) and vonBerg (approximately 4%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Executive officers as a group (excluding Mr. Coiner) own approximately 67% 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, 2007. 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	743,800(1)	N/A(2)	181,740(1)(3)
2005 Long Term Incentive Plan	1,723,490(4)	N/A(2)	996,184(3)
Equity compensation plans not approved by unitholders:			
1998 Long Term Incentive Plan	(1)(5)	N/A(2)	(6)
	(7)	$ 8.93(8)	(7)

General Partner s Performance Option Plan			
PPX Successor LTIP	150,050(9)	N/A(2)	849,759(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, 2007, 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, 2005 LTIP and PPX Successor 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 378,282 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 161,250 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, 2007, the strike price for all outstanding options under the general partner s Performance Option Plan was approximately $8.93 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, 2007 were approximately $287 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

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merger, our general partner agreed to a temporary reduction in the amount of incentive distributions 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 LP Distribution Per Unit	Distribution to LP Unitholders (1)(2)	Distribution to GP(1)(2)(3)	Total Distribution(2)	GP % of Total Distribution
$1.80	$ 208,800	$ 4,261	$ 213,061	2%
$1.98	$ 229,680	$ 7,946	$ 237,626	3%
$2.70	$ 313,200	$ 35,786	$ 348,986	10%
$3.40	$ 394,400	$ 116,986	$ 511,386	23%
$3.50	$ 406,000	$ 128,586	$ 534,586	24%
$3.75	$ 435,000	$ 157,586	$ 592,586	27%
$4.00	$ 464,000	$ 186,586	$ 650,586	29%

(1) In thousands.

(2) Assumes 116,000,000 units outstanding. Actual number of units outstanding as of December 31, 2007 was 115,981,676. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner for 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) for employees and directors of our general partner and its affiliates who perform services for us, and the PPX Successor LTIP for former Pacific employees or employees hired after the date of the Pacific merger (together with the 1998 LTIP and 2005 LTIP, the Plans). 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. The PPX Successor LTIP authorizes the grant of awards covering an aggregate of 999,809 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 newly issued common units, common units acquired by our general partner in the open market or in private transactions, common units acquired by us from any other person, 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, 2007, giving effect to vested grants, grants of approximately 743,800, 1,723,490 and 150,050 unvested phantom units were outstanding under the 1998 LTIP, 2005 LTIP and PPX Successor LTIP, respectively, and approximately 181,740, 996,184 and 849,759 remained available for future grant, respectively.

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. Because the awards are for services provided to the general partner, the expense associated with the awards is recorded on the general partner s financial statements. As of December 31, 2007, 161,250 options remained 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, 2007, the exercise price was approximately $8.93 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.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the creation and issuance of up to of 200,000 Class B units of Plains AAP, L.P. and authorized the compensation committee of Plains All American GP LLC to issue grants of Class B units to create long-term incentives for our management. The entire economic burden of the Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding. Therefore, we recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution, and thus results in a corresponding credit to Partners Capital in our Consolidated Financial Statements. The expense and capital contribution for the twelve months ended December 31, 2007 was approximately $3 million. We will not be obligated to reimburse Plains AAP, L.P. for such costs and any distributions made on the Class B units will not reduce the amount of cash available for distribution to our unitholders. Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values. As of December 31, 2007, 154,000 Class B units were issued and outstanding.

The Class B units are subject to restrictions on transfer and are not currently entitled to distributions. Class B units generally become earned (entitled to participate in distributions) in 25% increments when the annualized quarterly distributions on our common units equal or exceed $3.50, $3.75, $4.00 and $4.50 per unit. Upon achievement of these performance thresholds (or, in some cases, within six months thereafter), the Class B units will be entitled to their proportionate share of all quarterly cash distributions made by Plains AAP, L.P. in excess of $11 million per quarter (as adjusted for debt service costs and excluding special distributions funded by debt). Assuming all authorized Class B units are issued, the maximum participation would be 8% of the amount in excess of $11 million per quarter, as adjusted.

To encourage retention following achievement of these performance benchmarks, Plains AAP, L.P. retained a call right to purchase any earned Class B units at a discount to fair market value that is exercisable upon the termination of a holder s employment with Plains All American GP LLC and its affiliates for any reason prior to January 1, 2016, other than a termination of employment by the employee for good reason or by Plains All American GP LLC other than for cause (as defined). Upon the occurrence of a change of control (as defined), (i) all earned units will vest (no longer be subject to Plains AAP, L.P. s call right), and (ii) to the extent any of the units are unearned at the time, an incremental 25% of the units originally awarded will vest. All earned Class B units will also vest if they remain outstanding as of January 1, 2016 or Plains AAP, L.P. elects not to timely exercise its call right.

Transactions with Related Persons

Vulcan Energy

As of December 31, 2007, Vulcan Energy and its affiliates owned approximately 54% of our general partner interest, as well as approximately 11% 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.

Another owner of GP LLC, Lynx Holdings I, LLC, agreed to restrict certain of its voting rights with respect to its approximate 1.2% membership interest in GP LLC. See Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance Partnership Management and Governance.

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 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.

Omnibus Agreement. PAA, GP LLC, certain affiliated entities and Vulcan Energy are parties to an amended and restated omnibus agreement dated as of July 23, 2004. Pursuant to this agreement, Vulcan Energy has agreed, so long as Vulcan Energy or any of its affiliates owns an interest, directly or indirectly, in GP LLC, not to engage in or acquire any business engaged in the following activities:

- crude oil storage, terminalling and gathering activities in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than entities affiliated with Vulcan Energy and its affiliates (collectively, the Vulcan entities) or GP LLC, PAA, its operating partnerships and any controlled affiliates (collectively, the Plains entities);

crude oil marketing activities; and

transportation of crude oil by pipeline in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than the Plains entities.

These restrictions are subject to specified permitted exceptions and may be terminated by Vulcan Energy upon certain change of control events involving Vulcan Energy. The omnibus agreement further permits, except as otherwise restricted by the omnibus agreement or any other agreement, each Vulcan entity to engage in any business activity, including those that may be in direct competition with the Plains entities. Further, any owner of equity interests in Vulcan Energy may make passive investments in PAA s competitors so long as such owner does not directly or indirectly use any knowledge or confidential information it received through the ownership by a Plains entity to compete, or to engage in or become interested financially in any person that competes, in the restricted activities described above.

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.

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.

the Omnibus Agreement described above.

Crude Oil Purchases. Prior to August 2005, Vulcan Energy owned 100% of Calumet Florida L.L.C. (Calumet). From August 2005 to May 2007, Calumet was owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. In May 2007, Calumet was sold to BreitBurn Energy Partners L.P., of which Mr. Armstrong is a director, and ceased to be related to Vulcan Energy. In 2007, until the date that Calumet ceased to be related to Vulcan Energy, we purchased crude oil from Calumet for approximately $17 million.

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 13% and 19% 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 is managed by KACALP, Vulcan Capital and an affiliate of Encap each 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 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 3% 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. (CANPET). Mr. W. David Duckett, the President of PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P., owns approximately 38% 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. Mr. Duckett owns a 23% interest in Pivotal. The railcars were sold and the lease was assigned by Pivotal to the Andrews Companies LLC in 2007.

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. Mr. Capobianco owns a profits interest in Vulcan Gas Storage LLC. 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 $113 million, and Bluewater Natural Gas Holdings, LLC a subsidiary of PAA/Vulcan (Bluewater) entered into a $90 million credit facility contemporaneously with closing. In August 2006, the borrowing capacity under this facility was increased to $120 million. Approximately $112 million was outstanding under this credit facility as of February 20, 2008. 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 2008, 2009 and 2010. We recorded deferred revenue for receipt of a one-time 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. During 2007, we made an additional contribution of $9 million to PAA/Vulcan. Such contribution did not result in an increase to our ownership interest.

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 million, we will receive a distribution from PAA/Vulcan equal to $6 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

During 2007, we purchased approximately $1.7 million of oil from companies owned and controlled by funds managed by KACALP. We pay the same amount per barrel to these companies that we pay to other producers in the area.

Thomas Coiner, an employee in our marketing department, is the son of George R. Coiner, our former Senior Group Vice President. In 2007, Thomas Coiner received total cash compensation of approximately $764,000 (which amount includes quarterly and annual performance-based bonus payments totaling approximately $581,000).

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, 2007	Year Ended December 31, 2006
Audit fees(1)	$ 2.0	$ 2.4
Audit-related fees(2)	0.1	0.3
Tax fees(3)	1.3	1.6
All other fees(4)	0.2	0.9
Total	$ 3.6	$ 5.2

(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.

(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 either 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 the Current Report on 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 File No. 333-138888).
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 File No. 333-138888).
3.7	Third Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed January 4, 2008).
3.8	Fourth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 28, 2007 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed January 4, 2008).
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 (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.11	Bylaws of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	

	Amendment No. 3 dated August 16, 2007 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 August 22, 2007).
3.13	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (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, as trustee (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, as trustee (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, as trustee (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4 filed December 10, 2004, 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, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4 filed December 10, 2004, File No. 333-121168).
4.6	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, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.7	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated as of May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein 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).
4.8	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., the Subsidiary Guarantors named therein 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).
4.9	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., the Subsidiary Guarantors named therein 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).
4.10	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., the Subsidiary Guarantors named therein 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).
4.11	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., the Subsidiary Guarantors named therein 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).
4.12	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., the Subsidiary Guarantors named therein 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).

4.13	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 Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
4.14	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 Energy Partners, L.P. s Current Report on Form 8-K filed March 9, 2005).
4.15	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 (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.16	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, the Guarantors named therein 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).
4.17	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 6 1/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed September 28, 2005).
4.18	First Supplemental Indenture dated November 15, 2006 to Indenture dated as of September 23, 2005, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.19	Registration Rights Agreement dated as of July 26, 2006 among Plains All American Pipeline, L.P., Vulcan Capital Private Equity I LLC, Kayne Anderson MLP Investment Company and Kayne Anderson Energy Total Return Fund, Inc. (incorporated by reference to Exhibit 4.13 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.20	Registration Rights Agreement dated as of December 19, 2006 among Plains All American Pipeline, L.P., E-Holdings III, L.P., E-Holdings V, L.P., Kayne Anderson MLP Investment Company and Kayne Anderson Energy Development Company (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-3/A filed December 21, 2006, File No. 333-138888).
4.21	Twelfth Supplemental Indenture dated January 1, 2008 to Indenture dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee.
4.22	Second Supplemental Indenture dated January 1, 2008 to Indenture dated as of September 23, 2005, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.23	Fourth Supplemental Indenture dated January 1, 2008 to Indenture dated as of June 16, 2004, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, the

Guarantors named therein and Wells Fargo Bank, National Association, as trustee.

10.1	Second Amended and Restated Credit Agreement dated as of July 31, 2006 by and among Plains All American Pipeline, L.P., as US Borrower; PMC (Nova Scotia) Company and Plains Marketing Canada, L.P., as Canadian Borrowers; Bank of America, N.A., as Administrative Agent; Bank of America, N.A., acting through its Canada Branch, as Canadian Administrative Agent; Wachovia Bank, National Association and JPMorgan Chase Bank, N.A., as Co-Syndication Agents; Fortis Capital Corp., Citibank, N.A., BNP Paribas, UBS Securities LLC, SunTrust Bank, and The Bank of Nova Scotia, as Co-Documentation Agents; the Lenders party thereto; and Banc of America Securities LLC and Wachovia Capital Markets, LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 4, 2006).
10.2	Restated Credit Facility (Uncommitted Senior Secured Discretionary Contango Facility) dated November 19, 2004 among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 24, 2004).
10.3	Amended and Restated Crude Oil Marketing Agreement dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.4	Amended and Restated Omnibus Agreement dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.5	Contribution, Assignment and Amendment Agreement dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 27, 2001).
10.6	Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2001).
10.7	Separation Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed June 11, 2001).
10.8**	Pension and Employee Benefits Assumption and Transition Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed June 11, 2001).
10.9**	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005).
10.10**	Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.11**	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-8 filed December 11, 2001, File No. 333-74920).
10.12**	

	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13**	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).

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10.14	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed May 10, 2001).
10.15	Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.16	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.17	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.18	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.19**	Plains All American Inc. 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.20**	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004).
10.21**	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.22**	Directors Compensation Summary.
10.23	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2001).
10.24**	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.25**	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005).
10.26**	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005).
10.27**	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005).
10.28**	Form of LTIP Grant Letter (payment to entity) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed February 23, 2005).
10.29**	Form of Performance Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005).
10.30	Administrative Services Agreement between Plains All American GP LLC and Vulcan Energy Corporation dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005).
10.31	Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC dated September 13, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed September 19, 2005).
10.32	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to

	Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005).
10.33**	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 16, 2005).

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10.34**	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 16, 2005).
10.35	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005).
10.36	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005).
10.37	First Amendment dated as of April 20, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 21, 2005).
10.38	Second Amendment dated as of May 20, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed May 12, 2005).
10.39**	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.40**	Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.41	Third Amendment dated as of November 4, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.41 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.42	Fourth Amendment dated as of November 16, 2006 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.42 to the Annual Report on Form 10-K for the year ended December 31, 2006.
10.43	First Amendment dated May 9, 2006 to the Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC dated September 13, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed May 15, 2006).
10.44**	Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 23, 2006).
10.45**	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to the Annual Report on Form 10-K for the year ended December 31, 2006).
10.46**	Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.47	Joinder and Supplement dated effective June 20, 2007 among the Lenders party thereto, related to the Restated Credit Agreement dated November 19, 2004, as amended (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
10.48	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] by and between Plains All American Pipeline, L.P.,

PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Rangeland Pipeline Company, Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).

10.49**	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R. Coiner (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.50**	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 4, 2008).
10.51	Fifth Amendment to Restated Credit Agreement dated as of November 16, 2007, by and among Plains Marketing, L.P., Plains All American Pipeline, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 21, 2007).
10.52	Guaranty by Plains All American Pipeline, L.P. dated November 16, 2007 in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed November 21, 2007).
10.53	Contribution and Assumption Agreement, dated December 28, 2007, by and between Plains AAP, L.P. and PAA GP LLC (incorporated by reference to Exhibit 10.2 to the Current Report filed January 4, 2008).
10.54	Assumption, Ratification and Confirmation Agreement dated January 1, 2008 by Plains Midstream Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended.
21.1	List of Subsidiaries of Plains All American Pipeline, L.P..
23.1	Consent of PricewaterhouseCoopers LLP.
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350

Filed herewith

** Management compensatory plan or arrangement

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SIGNATURES

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

Plains All American Pipeline, L.P.

By: PAA GP LLC,

its general partner

By: Plains AAP, L.P.,

its sole member

By: Plains All American GP LLC,

its general partner

By: /s/ Greg L. Armstrong

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

February 28, 2008

By: /s/ Phillip D. Kramer

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

February 28, 2008

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

Name	Title	Date
/s/ Greg L. Armstrong **Greg L. Armstrong**	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	February 28, 2008
/s/ Harry N. Pefanis **Harry N. Pefanis**	President and Chief Operating Officer of Plains All American GP LLC	February 28, 2008
/s/ Phillip D. Kramer **Phillip D. Kramer**	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 28, 2008
/s/ Tina L. Val **Tina L. Val**	Vice President Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 28, 2008
/s/ David N. Capobianco **David N. Capobianco**	Director of Plains All American GP LLC	February 28, 2008
/s/ Everardo Goyanes **Everardo Goyanes**	Director of Plains All American GP LLC	February 28, 2008
/s/ Gary R. Petersen **Gary R. Petersen**	Director of Plains All American GP LLC	February 28, 2008
/s/ Robert V. Sinnott **Robert V. Sinnott**	Director of Plains All American GP LLC	February 28, 2008
/s/ Arthur L. Smith **Arthur L. Smith**	Director of Plains All American GP LLC	February 28, 2008
/s/ J. Taft Symonds **J. Taft Symonds**	Director of Plains All American GP LLC	February 28, 2008

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management has used the framework set forth in the report entitled Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to evaluate the effectiveness of the Partnership s internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership s internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of the Partnership s internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

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

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

February 28, 2008

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the consolidated statements of operations, of cash flows, of changes in partners capital, of comprehensive income and of changes in accumulated other comprehensive income present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2007 and 2006 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed the manner in which it accounts for equity-based compensation and purchases and sales with the same counterparty in 2006.

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

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

PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2008

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(in millions, except unit amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 24	$ 11
Trade accounts receivable and other receivables, net	2,561	1,725
Inventory	972	1,290
Other current assets	116	131
Total current assets	3,673	3,157
PROPERTY AND EQUIPMENT	4,938	4,190
Accumulated depreciation	(519)	(348)
	4,419	3,842
OTHER ASSETS		
Pipeline linefill in owned assets	284	266
Inventory in third-party assets	74	76
Investment in unconsolidated entities	215	183
Goodwill	1,072	1,026
Other, net	169	165
Total assets	$ 9,906	$ 8,715
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liablities	$ 2,577	$ 1,847
Short-term debt	960	1,001
Other current liabilities	192	177
Total current liabilities	3,729	3,025
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	1	3
Senior notes, net of unamortized net discount of $2 and $2, respectively	2,623	2,623
Other long-term liabilities and deferred credits	129	87
Total long-term liabilities	2,753	2,713

COMMITMENTS AND CONTINGENCIES (NOTE 11)				
PARTNERS CAPITAL				
Common unitholders (115,981,676 and 109,405,178 units outstanding at December 31, 2007 and 2006, respectively)		3,343		2,906
General partner		81		71
Total partners capital		3,424		2,977
Total liabilities and partners capital	$	9,906	$	8,715

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2007	2006	2005
	(in millions, except per unit data)		
REVENUES			
Crude oil, refined products and LPG sales and related revenues (includes buy/sell transactions of $0, $4,762 and $16,275, respectively)	$ 19,892	$ 22,136	$ 30,929
Pipeline tariff activities revenues	379	280	236
Other revenues	123	29	11
Total revenues	20,394	22,445	31,176
COSTS AND EXPENSES			
Crude oil, refined products and LPG purchases and related costs (includes buy/sell transactions of $0, $4,795 and $16,107, respectively)	19,001	21,474	30,435
Field operating costs	531	382	280
General and administrative expenses	164	134	103
Depreciation and amortization	180	100	84
Total costs and expenses	19,876	22,090	30,902
OPERATING INCOME	518	355	274
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	15	8	2
Interest expense (net of capitalized interest of $14, $6 and $2)	(162)	(86)	(59)
Interest income and other income (expense), net	10	2	1
Income before tax	381	279	218
Current income tax expense	(3)		
Deferred income tax expense	(13)		
Income before cumulative effect of change in accounting principle	365	279	218
Cumulative effect of change in accounting principle		6	
NET INCOME	$ 365	$ 285	$ 218
NET INCOME-LIMITED PARTNERS	$ 286	$ 247	$ 199
NET INCOME-GENERAL PARTNER	$ 79	$ 38	$ 19
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 2.54	$ 2.84	$ 2.77
Cumulative effect of change in accounting principle		0.07	

Net income	$	2.54	$	2.91	$	2.77
DILUTED NET INCOME PER LIMITED PARTNER UNIT						
Income before cumulative effect of change in accounting principle	$	2.52	$	2.81	$	2.72
Cumulative effect of change in accounting principle				0.07		
Net income	$	2.52	$	2.88	$	2.72
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING		113		81		69
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING		114		82		70

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007	2006	2005
		(in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 365	$ 285	$ 218
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	180	100	84
Cumulative effect of change in accounting principle		(6)	
SFAS 133 mark-to-market adjustment	24	4	19
Inventory valulation adjustment	1	6	
Gain on sale of investment assets	(4)		
Gain on sale of linefill	(12)		
Equity compensation charge	49	43	26
Income tax expense	16		
Noncash amortization of terminated interest rate hedging instruments	1	2	1
(Gain)/loss on foreign currency revaluation		4	2
Equity earnings in unconsolidated entities, net of distributions	(14)	(7)	(1)
Net cash paid for terminated interest rate hedging instruments		(2)	(1)
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	(743)	(731)	(299)
Inventory	340	(325)	(425)
Accounts payable and other current liabilities	593	351	400
Net cash provided by (used in) operating activities	796	(276)	24
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions (Note 3)	(127)	(1,264)	(30)
Additions to property and equipment	(548)	(341)	(164)
Investment in unconsolidated entities	(9)	(46)	(112)
Cash paid for linefill in assets owned	(19)	(4)	
Proceeds from sales of assets	40	4	9
Net cash used in investing activities	(663)	(1,651)	(297)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net repayment on long-term revolving credit facility		(299)	(143)
Net borrowings on working capital revolving credit facility	305	3	67
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	(359)	616	139
Proceeds from the issuance of senior notes		1,243	149
Net proceeds from the issuance of common units (Note 5)	383	643	264
Distributions paid to common unitholders (Note 5)	(370)	(225)	(178)
Distributions paid to general partner (Note 5)	(81)	(38)	(19)

Other financing activities		(2)		(16)		(8)
Net cash provided by (used in) financing activities		(124)		1,927		271
Effect of translation adjustment on cash		4		1		(1)
Net increase (decrease) in cash and cash equivalents		13		1		(3)
Cash and cash equivalents, beginning of period		11		10		13
Cash and cash equivalents, end of period	$	24	$	11	$	10
Cash paid for interest, net of amounts capitalized	$	186	$	122	$	80
Cash paid for income taxes	$	3	$		$	

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS CAPITAL
(in millions)

	Common Units		Class B Common Units		Class C Common Units		General Partner	Total	Partners Capital
	Units	Amount	Units	Amount	Units	Amount	Amount	Units	Amount
Balance at December 31, 2004	63	$ 920	1	$ 19	3	$ 100	$ 31	67	$ 1,070
Net income		197		1		1	19		218
Distributions		(175)		(1)		(2)	(19)		(197)
Issuance of common units	7	258					6	7	264
Issuance of common units under Long Term Incentive Plans (LTIP)		2							2
Conversion of Class B units	1	18	(1)	(18)					
Conversion of Class C units	3	99			(3)	(99)			
Other comprehensive loss		(25)		(1)					(26)
Balance at December 31, 2005	74	$ 1,294		$		$	$ 37	74	$ 1,331
Net income		247					38		285
Distributions		(225)					(38)		(263)
Issuance of common units in connection with Pacific acquisition	22	1,002					22	22	1,024
Issuance of common units	13	609					12	13	621
Other comprehensive loss		(21)							(21)
Balance at December 31, 2006	109	$ 2,906		$		$	$ 71	109	$ 2,977
Net income		286					79		365
Distributions		(370)					(81)		(451)
Issuance of common units	6	375					8	6	383
Issuance of common units under LTIP	1	17						1	17
		2					1		3

GP Class B units (Note 10)											
Other comprehensive income			127					3			130
Balance at December 31, 2007	116	$	3,343	$		$	$	81	116	$	3,424

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2007	2006	2005
	(in millions)		
Net income	$ 365	$ 285	$ 218
Other comprehensive income/(loss)	130	(21)	(26)
Comprehensive income	$ 495	$ 264	$ 192

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(in millions)	
Balance at December 31, 2004	$ 26	$ 71	$ 97
Reclassification adjustments for settled contracts	117		117
Changes in fair value of outstanding hedge positions	(159)		(159)
Currency translation adjustment		16	16
2005 Activity	(42)	16	(26)
Balance at December 31, 2005	$ (16)	$ 87	$ 71
Reclassification adjustments for settled contracts	(146)		(146)
Changes in fair value of outstanding hedge positions	142		142
Currency translation adjustment		(17)	(17)
2006 Activity	(4)	(17)	(21)
Balance at December 31, 2006	$ (20)	$ 70	$ 50
Reclassification adjustments for settled contracts	11		11
Changes in fair value of outstanding hedge positions	13		13
Currency translation adjustment		106	106
2007 Activity	24	106	130
Balance at December 31, 2007	$ 4	$ 176	$ 180

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 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 subsidiaries, unless 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 are also involved in the development and operation of natural gas storage facilities. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. See Note 15.

Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P. s general partner. Plains All American GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and personnel are employed by our subsidiary PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P. References to our general partner, as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners with interests ranging from 54% to 1%.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2007 and 2006, and the consolidated results of our operations, cash flows, changes in partners capital, comprehensive income and changes in accumulated other comprehensive income for the years ended December 31, 2007, 2006 and 2005. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to the previous years to conform to the 2007 presentation. These reclassifications do not affect net income. The accompanying consolidated financial statements include Plains and all of its wholly owned subsidiaries. Investments in 50% or less owned entities over which we have significant influence but not control are accounted for by the equity method. We evaluate our equity investments for impairment in accordance with APB 18: *The Equity Method of Accounting for Investments in Common Stock.* An impairment of an equity investment results when factors indicate that the investment s fair value is less than its carrying value and the reduction in value is other than temporary in nature.

Changes in Accounting Principles

Stock-Based Compensation. In December 2004, Statement of Financial Accounting Standards (SFAS) No. 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 gain of approximately $6 million related to the cumulative effect of change in accounting principle. The cumulative effect adjustment represents a decrease to our LTIP life-to-date

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 related to LTIP settlements. Our LTIP awards are classified as liabilities under SFAS 123(R) as the awards are primarily paid in cash. Under the modified prospective transition method, we are not required to adjust our prior period financial statements for this change in accounting principle.

Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the Emerging Issues Task Force (EITF) issued Issue No. 04-13 (EITF 04-13), Accounting for Purchases and Sales of Inventory with the Same Counterparty. The EITF concluded that inventory purchase and sale transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 became effective in reporting periods beginning after March 15, 2006.

We adopted EITF 04-13 on April 1, 2006. The adoption of EITF 04-13 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. In conformity with EITF 04-13, prior periods are not affected, although we have parenthetically disclosed prior period buy/sell transactions in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases and related costs on our income statement but does not impact our financial position, net income, or liquidity.

Note 2 Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates we make include: (i) accruals related to purchases and sales, (ii) mark-to-market estimates pursuant to Statement of Financial Accounting Standards (SFAS) No. 133 Accounting For Derivative Instruments and Hedging Activities, as amended (SFAS 133), (iii) accruals and contingent liabilities, (iv) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (v) accruals related to our equity compensation plans and (vi) property, plant, and equipment and depreciation expense. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Transportation Segment Revenues. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and refined products at a published tariff as well as revenues associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line-lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized. All pipeline tariff and fee revenues are based on actual volumes and rates.

Facilities Segment Revenues. Storage and terminalling revenues (which are included within Other Revenues on our Consolidated Statements of Operations) consist of (i) storage fees from actual storage used on a month-to-month basis; (ii) storage fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer in a given month; and (iii) terminal throughput charges to pump to connecting

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

carriers. Revenues on storage are recognized ratably over the term of the contract. Terminal throughput charges are recognized as the crude oil, LPG or refined product exits the terminal and is delivered to the connecting carrier or third-party terminal. Any throughput volumes in transit at the end of a given month are treated as third-party inventory and do not incur storage fees. All terminalling and storage revenues are based on actual volumes and rates.

Marketing Segment Revenues. Revenues from sales of crude oil, refined products and LPG are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Sales of crude oil, refined products and LPG consist of outright sales contracts and buy/sell arrangements as well as exchanges.

The adoption of EITF 04-13 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. In conformity with EITF 04-13, prior periods are not affected, although we have parenthetically disclosed prior period buy/sell transactions in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases and related costs on our income statement but does not impact our financial position, net income, or liquidity.

Purchases and Related Costs

Purchases and related costs include: (i) the cost of crude oil, refined products and LPG purchased in outright purchases as well as buy/sell arrangements prior to the adoption of EITF 04-13; (ii) third-party transportation and storage, whether by pipeline, truck or barge; (iii) interest cost attributable to borrowings for inventory stored in a contango market; (iv) performance-related bonus accruals; and (v) expenses of issuing letters of credit to support these purchases. These purchases are recorded at the time title transfers to us.

Field Operating Costs and General and Administrative Expenses

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

Foreign Currency Transactions

Assets and liabilities of subsidiaries with a functional currency other than the U.S. Dollar are translated at period-end rates of exchange, and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income in partners capital. Gains and losses from foreign currency transactions (transactions denominated in a currency other than the entity s functional currency) are included in the consolidated statement of operations in other income. The foreign currency transactions resulted in a gain of less than $1 million for the year ended December 31, 2007, and in losses of approximately $4 million and $2 million for the years ended December 31, 2006 and 2005, respectively.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that the credit risk is minimal. As of December 31, 2007 and 2006, accounts payable included approximately $63 million and $52 million, respectively, of outstanding checks that were reclassed from cash and cash equivalents.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of refined products and LPG. The majority of our accounts receivable relate to our crude oil marketing activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or parental guarantees. At December 31, 2007 and 2006, we had received approximately $43 million and $28 million, respectively, of advance cash payments and prepayments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2007 and 2006, substantially all of our net accounts receivable classified as current assets were less than 60 days past their scheduled invoice date, and our allowance for doubtful accounts receivable totaled $1 million and $1 million, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Inventory and Pipeline Linefill

Inventory primarily consists of crude oil, refined products and LPG in pipelines, storage tanks and rail cars that is valued at the lower of cost or market, with cost determined using an average cost method. During 2007 and 2006, we recorded a $1 million and $6 million noncash charge, respectively, related to the writedown of our crude oil and LPG inventory due to declines in oil prices during the third and fourth quarters of 2006. There was no such charge in 2005. Linefill and minimum working inventory requirements in assets we own are recorded at historical cost and consist of crude oil and LPG used to pack the pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location, as well as the minimum amount of crude oil necessary to operate our storage and terminalling facilities. During 2007, we recorded a gain of approximately $12 million on the sale of pipeline linefill (for proceeds of approximately $20 million).

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Inventory and linefill consisted of (barrels in thousands and dollars in millions):

	December 31, 2007			December 31, 2006		
	Barrels	Dollars	Dollar/ Barrel(2)	Barrels	Dollars	Dollar/ Barrel(2)
Inventory(1)						
Crude oil	7,365	$ 592	$ 80.38	18,331	$ 1,029	$ 56.13
LPG	6,480	363	$ 56.02	5,818	251	$ 43.14
Refined products	133	11	$ 82.71	81	4	$ 49.38
Parts and supplies	N/A	6	N/A	N/A	6	N/A
Inventory subtotal	13,978	972		24,230	1,290	
Inventory in third-party assets						
Crude oil	986	64	$ 64.91	1,212	63	$ 51.98
LPG	175	10	$ 57.14	318	13	$ 40.88
Inventory in third-party assets subtotal	1,161	74		1,530	76	
Pipeline linefill in owned assets						
Crude oil	7,734	282	$ 36.46	7,831	265	$ 33.84
LPG	43	2	$ 46.51	31	1	$ 32.26
Pipeline linefill in owned assets subtotal	7,777	284		7,862	266	
Total	22,916	$ 1,330		33,622	$ 1,632	

(1) Includes the impact of inventory hedges on a portion of our volumes.

(2) The prices listed represent a weighted average associated with various grades and qualities of crude oil, LPG and refined products and, accordingly, is not a comparable metric with published benchmarks for such products.

Property and equipment

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. For the years ended December 31, 2007, 2006 and 2005, capitalized interest was $14 million, $6 million and $2 million, respectively. In addition, costs required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives are capitalized and classified as maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

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

	Estimated Useful Lives (Years)	December 31, 2007	December 31, 2006
Crude oil pipelines and facilities	30-40	$ 3,603	$ 3,239
Crude oil and LPG storage and terminal facilities	30-40	599	373
Trucking equipment and other	5-15	233	200
Office property and equipment	3-5	64	38
Construction in progress		439	340
		4,938	4,190
Less accumulated depreciation		(519)	(348)
Property and equipment, net		$ 4,419	$ 3,842

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Depreciation expense for each of the three years in the period ended December 31, 2007 was $160 million, $91 million and $79 million, respectively.

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

Equity Method of Accounting

Our investments in PAA/Vulcan, Frontier Pipeline Company (Frontier), Settoon Towing, LLC (Settoon Towing) and Butte Pipe Line Company (Butte) are accounted for under the equity method of accounting. Our ownership interests in PAA/Vulcan, Frontier, Settoon Towing and Butte are 50%, 22%, 50% and 22%, respectively. We do not consolidate any part of the assets or liabilities of our equity investees. Our share of net income or loss is reflected as one line item on the income statement and will increase or decrease, as applicable, the carrying value of our investments on the balance sheet. Distributions to the Partnership will reduce the carrying value of our investments and will be reflected on our cash flow statement against equity in earnings.

Asset Retirement Obligations

We account for asset retirement obligations under SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS 143). 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 (settlement date), (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

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.

Many of our pipelines are trunk and interstate systems that transport crude oil and we have determined that the settlement date related to the retirement obligation has an indeterminate life. 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 have recorded a reasonable estimate of these obligations. We

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have estimated that the fair value of these obligations was approximately $8 million and $5 million at December 31, 2007 and 2006, respectively.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, as amended (SFAS 144). Under SFAS 144, a long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized.

We periodically evaluate property, plant and equipment for impairment 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.

Impairments were not material in 2007, 2006 or 2005. The impairments, which were predominantly related to assets that will be taken out of service, are included as a component of depreciation and amortization in the consolidated statements of operations. These assets did not support spending the capital necessary to continue service and we utilized other assets to handle these activities.

Goodwill

In accordance with SFAS No. 142, Goodwill and Other Intangible Assets, (SFAS 142) we test goodwill at least annually (as of June 30) to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. Pursuant to SFAS 142, a reporting unit is an operating segment or one level below an operating segment for which discrete financial information is available and regularly reviewed by segment management. Our reporting units are our operating segments. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. Fair value is assessed based on multiples of earnings or revenue. An impairment loss is recognized if the carrying amount is not recoverable and its carrying amount exceeds its fair value. Since adoption of SFAS 142, we have not recognized any impairment of goodwill.

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The table below reflects our changes in goodwill (in millions):

	Transportation	Facilities	Marketing	Total
Balance at December 31, 2005	$	$ 1	$ 47	$ 48
2006 Additions				
Pacific	393	190	260	843
Andrews	6	58	6	70
SemCrude			63	63
Other			2	2
Balance at December 31, 2006	$ 399	$ 249	$ 378	$ 1,026
2007 Additions				
Pacific(1)		30	2	32
Andrews(1)		4	(6)	(2)
Jasper/Oil Central			7	7
RMC Transportation	5			5
Other			4	4
Balance at December 31, 2007	$ 404	$ 283	$ 385	$ 1,072

(1) Change is due to purchase price adjustments.

Other assets, net

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

	December 31, 2007	December 31, 2006
Debt issue costs	$ 28	$ 29
Fair value of derivative instruments	26	9
Intangible assets	124	123
Other	18	19
	196	180
Less accumulated amortization	(27)	(15)

	$ 169	$ 165

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the effective interest method of amortization. Fully amortized debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized debt issue costs of approximately $1 million, $13 million and $3 million in 2007, 2006 and 2005, respectively. In addition, during 2007 and 2006 we wrote off approximately $2 million and $1 million, respectively, of fully amortized costs and the related accumulated amortization. During 2007 and 2006 we did not write off any unamortized costs. During 2005 we wrote off unamortized costs totaling $1 million.

Amortization expense related to other assets (including finite-lived intangible assets) for each of the three years in the period ended December 31, 2007, was $13 million, $9 million and $4 million, respectively.

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Intangible assets that have finite lives are tested for impairment when events or circumstances indicate that the carrying value may not be recoverable. Our intangible assets that have finite lives consist of the following (in millions):

	Estimated Useful Lives (Years)	December 31, 2007			December 31, 2006		
		Cost	Accumulated Amortization	Net	Cost	Accumulated Amortization	Net
Customer contracts and relationships	4-17	$ 84	$ (12)	$ 72	$ 82	$ (5)	$ 77
Emission reduction credits(1)	N/A	34		34	33		33
Environmental permits	2	6	(4)	2	8	(1)	7
		$ 124	$ (16)	$ 108	$ 123	$ (6)	$ 117

(1) Emission reduction credits are finite-lived and are subject to amortization from the date that they are first utilized. At December 31, 2007, none of our emission reduction credits were being utilized because the projects for which they were acquired were still under construction at December 31, 2007.

Our amortization expense for finite-lived intangible assets for the years ended December 31, 2007, 2006 and 2005 was $10 million, $5 million and less than $1 million, respectively.

We estimate that our amortization expense related to finite-lived intangible assets for the next five years will be as follows (in millions):

2008	$ 10
2009	7
2010	6
2011	4
2012	4

Environmental Matters

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We also record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

We expense expenditures that relate to an existing condition caused by past operations that do not contribute to current or future profitability. We record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. See Note 13.

Income and Other Taxes

U.S. Federal and State Taxes. As a master limited partnership, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. In May 2006, the State of Texas enacted a new business tax (the Texas Margin Tax) that replaced its franchise tax. In general, any entity that conducts business in Texas is subject to the Texas Margin Tax. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax because it is determined by applying a tax rate to a base that

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considers both revenue and expenses. The Texas Margin Tax is effective for returns originally due on or after January 1, 2008. For calendar year end companies such as us, the margin tax is applied to 2007 activity.

Canadian Federal and Provincial Taxes. Certain of our Canadian subsidiaries (acquired through the Pacific merger in 2006) are corporations for Canadian tax purposes, thus their operations are subject to Canadian federal and provincial income taxes. The remainder of our Canadian operations is conducted through an operating limited partnership, which in the past was a flow-through entity for tax purposes. In June 2007, Canadian legislation was passed that imposes entity-level taxes on certain types of flow- through entities. The legislation refers to safe harbor guidelines that grandfather certain existing entities and delay the effective date of such legislation until 2011 provided that the entities do not exceed the normal growth guidelines. Although limited guidance is currently available, we believe that the legislation will apply to our Canadian partnerships. We believe that we are currently within the normal growth guidelines as defined in the legislation, which should delay the effective date for us until 2011. See Note 7.

We estimate (a) income taxes in the jurisdictions in which we operate, (b) net deferred tax assets and liabilities based on expected future taxes in the jurisdictions in which we operate, (c) valuation allowances for deferred tax assets and (d) contingent tax liabilities for estimated exposures related to our current tax positions. These estimates depend on assumptions regarding our ability to generate future taxable income during the periods in which temporary differences are deductible. See Note 7.

As of December 31, 2007, we have not recorded a valuation allowance against our deferred tax assets for federal net operating loss carryforwards. Management believes that it is more likely than not that we will realize the deferred tax assets associated with the federal net operating loss. Key factors in this assessment include an evaluation of our recent history of taxable earnings and losses (as adjusted), future reversals of temporary differences and identification of other sources of future taxable income, including the identification of tax planning strategies.

Recent Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 160 Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (SFAS 160). SFAS 160 requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. The pronouncement eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring that they be treated as equity transactions. The provisions of SFAS 160 are effective on a prospective basis for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. We will adopt SFAS 160 on January 1, 2009 and do not anticipate that such adoption will have any material impact on our consolidated financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R) Business Combinations (SFAS 141(R)). SFAS 141(R) establishes principles and requirements for how an acquirer: (i) recognizes and measures in its financial statements the identifiable assets aquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill aquired in the business combination or a gain from a bargain purchase and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The provisions of SFAS 141(R) will be effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We will adopt SFAS 141(R) on January 1, 2009. Adoption will impact our accounting for acquisitions subsequent to that date.

In February 2007, the FASB issued SFAS No. 159 The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FAS 115 (SFAS 159). SFAS 159 allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value in situations in which they are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item,

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changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. The provisions of SFAS 159 will be effective for fiscal years beginning after November 15, 2007. We will adopt SFAS 159 on January 1, 2008, but we do not anticipate making any elections to value any eligible assets or liabilities at fair value and thus do not expect that adoption will have a material impact on our consolidated financial position, results of operations or cash flows.

In December 2006, the FASB issued FASB Staff Position EITF 00-19-2, Accounting for Registration Payment Arrangements (the FSP). The FSP specifies that the contingent obligation to make future payments under a registration payment arrangement should be separately recognized and measured in accordance with FASB Statement No. 5 Accounting for Contingencies. The FSP was effective immediately for registration payment arrangements and the financial instruments subject to those arrangements entered into or modified subsequent to December 21, 2006. For registration payment arrangements and for the financial instruments subject to those arrangements that were entered into prior to December 21, 2006, the FSP is effective for fiscal years beginning after December 15, 2006. At December 31, 2007, we did not have any material contingent obligations under registration payment arrangements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. SFAS 157 does not add any new fair value measurements, but it does change current practice and is intended to increase consistency and comparability in such measurement. The provisions of SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The impact, if any, to the company from the adoption of FAS 157 in 2008 will depend on the company s assets and liabilities that are required to be measured at fair value at that time. We are still evaluating the impact of adoption of SFAS 157 but we do not expect that it will have a material impact on our consolidated financial position, results of operations or cash flows.

In September 2006, the FASB issued FASB Staff Position AUG AIR-1, Accounting for Planned Major Maintenance Activities (FSP AUG AIR-1). FSP AUG AIR-1 prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities. FSP AUG AIR-1 is effective for the first fiscal year beginning after December 15, 2006. We expense major maintenance activities as incurred. The adoption of FSP AUG AIR-1 on January 1, 2007 did not have any impact on our financial position, results of operations or cash flows.

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. In addition, FIN 48 provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized as an adjustment to the opening balance of retained earnings (or other appropriate components of equity) for that fiscal year. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. We adopted FIN 48 as of January 1, 2007. The adoption of this Standard did not have a material impact on our financial position, results of operations or cash flows.

In June 2006, the EITF issued Issue No. 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation) (EITF 06-3). EITF 06-3 is effective for all periods beginning after December 15, 2006 and its scope includes any tax that is assessed by a governmental authority that is both imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer. The EITF stated that it is an entity s accounting policy decision whether to present the taxes on a gross basis (within revenues and costs) or on a net basis (excluded from

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revenues) but that the accounting policy should be disclosed. If presented on a gross basis, an entity is required to report the amount of such taxes for each period for which an income statement is presented, if those amounts are significant. Our accounting policy is to present such taxes on a net basis.

Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled commodity trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. We record all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS No. 133, Accounting For Derivative Instruments and Hedging Activities, as amended (SFAS 133). SFAS 133 requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value of cash flow hedges are deferred to Accumulated Other Comprehensive Income (AOCI) and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives that do not qualify for hedge accounting and (ii) the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of hedged items. See Note 6 for further discussion.

Net Income Per Unit

Except as discussed in the following paragraph, basic and diluted net income per limited partner unit is determined by dividing net income after deducting the amount allocated to the general partner (including the incentive distribution interest in excess of the 2% general partner interest) by the weighted average number of outstanding limited partner units during the period. Subject to applicability of Emerging Issues Task Force Issue No. 03-06 (EITF 03-06), Participating Securities and the Two-Class Method under FASB Statement No. 128, as discussed below, Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership.

EITF 03-06 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. Essentially, EITF 03-06 provides that in any accounting period where our aggregate net income exceeds our aggregate distribution for such period, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective.
EITF 03-06 does not impact our overall net income or other financial results; however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit. This result occurs because a larger portion of our aggregate earnings is allocated (as if distributed) to our general partner, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such period, EITF 03-06 does not have any impact on our earnings per unit calculation.

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The following sets forth the computation of basic and diluted earnings per limited partner unit. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents at 2007, 2006 and 2005 (amounts in millions, except per unit data).

	Year Ended December 31,		
	2007	**2006**	**2005**
Numerator:			
Net income	$ 365	$ 285	$ 218
Less: General partner s incentive distribution paid	(73)	(33)	(15)
Subtotal	292	252	203
Less: General partner 2% ownership	(6)	(5)	(4)
Net income available to limited partners	286	247	199
Less: Pro forma EITF 03-06 additional general partner s distribution		(11)	(7)
Net income available to limited partners under EITF 03-06	286	236	192
Less: Limited partner 98% portion of cumulative effect of change in accounting principle		(6)	
Limited partner net income before cumulative effect of change in accounting principle	$ 286	$ 230	$ 192
Denominator:			
Basic earnings per limited partner unit (weighted average number of limited partner units outstanding)	113	81	69
Effect of dilutive securities:			
LTIP units outstanding(1)	1	1	1
Diluted earnings per limited partner unit (weighted average number of limited partner units outstanding)	114	82	70
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 2.54	$ 2.84	$ 2.77
Cumulative effect of change in accounting principle per limited partner unit		0.07	
Basic net income per limited partner unit	$ 2.54	$ 2.91	$ 2.77
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 2.52	$ 2.81	$ 2.72
Cumulative effect of change in accounting principle per limited partner unit		0.07	

Diluted net income per limited partner unit	$ 2.52	$ 2.88	$ 2.72

(1) Our LTIP awards described in Note 10 that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. The dilutive securities are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in SFAS 128, Earnings per Share.

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Note 3 Acquisitions and Dispositions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price was allocated in accordance with such method.

2007 Acquisitions

During 2007, we completed four acquisitions for aggregate consideration of approximately $123 million. These acquisitions included (i) a commercial refined products supply and marketing business (reflected in our marketing segment) for approximately $8 million in cash, (ii) a trucking business (reflected in our transportation segment) for approximately $9 million in cash, (iii) the Bumstead LPG storage facility located near Phoenix, Arizona (reflected in our facilities segment) for approximately $52 million in cash and (iv) the Tirzah LPG storage facility and other assets located near York County, South Carolina (reflected in our facilities segment) for approximately $54 million in cash. The goodwill associated with these acquisitions was approximately $12 million.

2006 Acquisitions

Pacific Energy Partners, L.P. On November 15, 2006 we completed our acquisition of Pacific Energy Partners, L.P. (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 million Pacific common units and approximately 5 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 Pacific merger). The assets acquired in the Pacific merger 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 2 million barrels of crude oil and refined products linefill and working inventory.

The purchase price consisted of the following (in millions):

Cash payment to LB Pacific	$ 700
Value of Plains common units issued in exchange for Pacific common units(1)	1,002
Assumption of Pacific debt (at fair value)	724
Transaction costs(2)	30
Total purchase price	$ 2,456

(1) Valued at $45.02, which represents the average closing price of Plains common units two days immediately prior and two days immediately after the merger was announced on June 12, 2006.

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

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Purchase Price Allocation (in millions)	
Property, plant and equipment, net	$ 1,385
Investment in Frontier	18
Inventory	34
Pipeline linefill and inventory in third party assets	66
Intangible assets(1)	69
Goodwill(2)(3)	875
Assumption of working capital and other long-term assets and liabilities, including $20 of cash	9
	$ 2,456

(1) Consists of customer relationships, emissions credits and environmental permits.

(2) Represents the 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. See Note 2.

(3) Includes adjustments recorded during the year ended December 31, 2007, primarily resulting from the final valuation of assets and liabilities acquired.

The majority of the acquisition costs associated with the Pacific merger were 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 merger (in millions):

Fair value of Plains common units issued in exchange for Pacific common units	$ 1,002
Plains general partner capital contribution	22
Assumption of Pacific debt (at fair value), net of repayment of Pacific credit facility(1)	433
Plains new debt incurred	999
Total sources of funding	$ 2,456

(1) The assumption of Pacific s debt and credit facility at fair value was $433 million and $291 million, respectively. We paid off the credit facility in connection with closing of the transaction.

Other 2006 Acquisitions. During 2006, in addition to the Pacific merger, 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, 64% interest in the Clovelly-to-Meraux (CAM) Pipeline system and various interests in the High Island Pipeline System (HIPS), and (iv) three refined products pipeline systems from Chevron Pipe Line Company.

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The aggregate purchase prices of these acquisitions were allocated as follows (in millions):

Inventory	$ 35
Linefill	19
Inventory in third party assets	2
Property and equipment	327
Goodwill(1)	133
Intangibles(2)	49
Net other assets and liabilities	
Total Purchase Price	$ 565

(1) Represents the 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. See Note 2.

(2) Consists of customer relationships.

In addition, in November 2006, we acquired a 50% interest in Settoon Towing for approximately $34 million.

Pro Forma Data. The results of operations and assets and liabilities from the Pacific merger have been included in our consolidated financial statements and all three of our segments since November 15, 2006. The following table presents selected unaudited pro forma financial information incorporating the historical (pre-merger) results of Pacific and our other 2006 business combination transactions (amounts in millions, except per unit data). The following pro forma information has been prepared as if the Pacific merger and our other business combination transactions in 2006 had been completed on January 1, 2006 as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon available data and includes certain estimates and assumptions made by management. As a result, this pro forma information is not necessarily indicative of our financial results had the transactions actually occurred on this date. Likewise, the following unaudited pro forma financial information is not necessarily indicative of our future financial results.

	Year Ended December 31, 2006 (Unaudited)
Revenues	$ 22,996
Income before cumulative effect of change in accounting principle	$ 309
Net income	$ 316

Basic income before cumulative effect of change in accounting principle per limited partner unit	$	2.68
Diluted income before cumulative effect of change in accounting principle per limited partner unit	$	2.74
Basic net income per limited partner unit	$	2.66
Diluted net income per limited partner unit	$	2.72

2005 Acquisitions.

During 2005, we completed six small transactions for aggregate consideration of approximately $40 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. In addition, in September 2005, PAA/Vulcan acquired Energy Center Investments LLC (ECI), an indirect subsidiary of Sempra Energy, for

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approximately $250 million. We own 50% of PAA/Vulcan and a subsidiary of Vulcan Capital owns the other 50%. See Note 9.

Dispositions

During 2007, 2006 and 2005, we sold various property and equipment for proceeds totaling approximately $13 million, $4 million and $9 million, respectively. A loss of approximately $7 million, a gain of $2 million, and a loss of $3 million were recognized in 2007, 2006, and 2005, respectively. These gains and losses are included as a component of depreciation and amortization in the consolidated statements of operations.

Note 4 Debt

Debt consists of the following (in millions):

	December 31, 2007	December 31, 2006
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 5.3% and 5.8% at December 31 2007 and 2006, respectively	$ 476	$ 835
Working capital borrowings, bearing interest at a rate of 5.5% and 5.9% at December 31 2007 and 2006, respectively(1)	482	158
Other	2	8
Total short-term debt	960	1,001
Long-term debt:		
4.75% senior notes due August 2009	175	175
7.75% senior notes due October 2012	200	200
5.63% senior notes due December 2013	250	250
7.13% senior notes due June 2014	250	250
5.25% senior notes due June 2015	150	150
6.25% senior notes due September 2015	175	175
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized premium/(discount), net	(2)	(2)
Long-term debt under credit facilities and other(2)	1	3
Total long-term debt(1)(3)	2,624	2,626
Total debt	$ 3,584	$ 3,627

(1) At December 31, 2007 and 2006, we have classified $482 million and $158 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin deposits.

(2) Includes adjustment related to fair value hedge. Fair value hedge accounting was discontinued subsequent to June 30, 2007. The outstanding balance will be amortized over the remaining life of the underlying debt.

(3) At December 31, 2007, the aggregate fair value of our fixed-rate senior notes is estimated to be approximately $2,655 million. 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 reflect market.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Credit Facilities

As of December 31, 2007 and 2006, the borrowing capacity under our senior secured hedged inventory facility was $1.2 billion and $1.0 billion, respectively. The borrowing capacity of this facility can be expanded to $1.4 billion subject to additional lender commitments. The maturity of this facility is November 2008 and Plains All American Pipeline, L.P. was added as a guarantor in 2007. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. At December 31, 2007 and 2006, borrowings of approximately $476 million and $835 million, respectively, were outstanding under this facility.

As of December 31, 2007 and 2006, the aggregate borrowing capacity of our senior unsecured revolving credit facility was $1.6 billion and $1.6 billion, respectively (including the sub-facility for Canadian borrowings of $600 million and $600 million, respectively). This credit facility, among other things, has a maximum debt coverage ratio during an acquisition period of 5.5 to 1.0 and maturity date of July 2012. Also, the senior unsecured revolving credit facility can be expanded to $2.0 billion, subject to additional lender commitments. At December 31, 2007 and 2006, borrowings of approximately $635 million and $344 million, respectively, were outstanding under this facility (including letters of credit).

Senior Notes

In November 2006, in conjunction with the Pacific merger, we assumed two issues of Senior Notes with an aggregate principal balance of $425 million. The $175 million of 6.25% Senior Notes are due September 15, 2015 and the $250 million of 7.125% Senior Notes are due June 15, 2014. Interest payments on the 6.25% Senior Notes are due on March 15 and September 15 of each year, and interest payments on the 7.125% Senior Notes are due on June 15 and December 15 of each year. These notes were recorded at fair value for an aggregate amount of $433 million.

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 the merger with Pacific including repayment of amounts outstanding under Pacific s credit facility. 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%. See Note 6.

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.

In each instance, the notes were co-issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for two subsidiaries with assets regulated by the California Public Utility Commission, and certain other minor subsidiaries. See Note 12.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Covenants and Compliance

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

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

Our senior unsecured revolving credit facility treats a change of control as an event of default and also requires us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 4.75 to 1.0 on outstanding debt, and 5.5 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

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

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

Letters of Credit

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. These letters of credit are issued under our senior unsecured revolving credit facility, and our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2007 and 2006, we had outstanding letters of credit of approximately $153 million and $186 million, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2007 was approximately 14 years and the aggregate maturities for the next five years are as follows (in millions):

Calendar

Year	Payment
2008	$ 2
2009	175
2010	1
2011	
2012	200
Thereafter	2,251
Total(1)	$ 2,629

(1) Excludes aggregate unamortized discount, net, of $2 million on our various senior notes.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5 Partners Capital and Distributions

Units Outstanding

Partners capital at December 31, 2007 consists of 115,981,676 common units outstanding, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries after giving effect to the 2% general partner interest.

GP Class B Units

In August 2007, the owners of Plains AAP, L.P. authorized the creation and issuance of up to 200,000 Class B units in Plains AAP, L.P., and authorized the board of directors of Plains All American GP LLC to issue grants. At December 31, 2007, approximately 154,000 Class B units have been granted and the remaining units are reserved for future grants. (See Note 10)

Conversion of PAA Class B and Class C Common Units

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

Distributions

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 by our general partner for future requirements.

General Partner Incentive Distributions

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally the general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, referred to as our minimum quarterly distributions (MQD), 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as incentive distributions).

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amount of its incentive distributions 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 first reduction was with respect to the incentive distribution paid to the general partner on February 14, 2007, which was reduced by $5 million. The total reduction in incentive distributions will be $65 million. Following the distribution in February 2008, the aggregate remaining incentive distribution reduction was $41 million.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Per unit cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	2007		2006		2005	
	Distribution	Excess over MQD	Distribution	Excess over MQD	Distribution	Excess over MQD
First Quarter	$ 0.8000	$ 0.3500	$ 0.6875	$ 0.2375	$ 0.6125	$ 0.1625
Second Quarter	$ 0.8125	$ 0.3625	$ 0.7075	$ 0.2575	$ 0.6375	$ 0.1875
Third Quarter	$ 0.8300	$ 0.3800	$ 0.7250	$ 0.2750	$ 0.6500	$ 0.2000
Fourth Quarter	$ 0.8400	$ 0.3900	$ 0.7500	$ 0.3000	$ 0.6750	$ 0.2250

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

Total cash distributions made were as follows (in millions, except per unit amounts):

	Distributions Paid				Distributions
	Common	General Partner			per limited
Year	Units	Incentive	2%	Total	partner unit
2007	$ 370	$ 73	$ 8	$ 451	$ 3.28
2006	$ 225	$ 33	$ 5	$ 263	$ 2.87
2005	$ 178	$ 15	$ 4	$ 197	$ 2.58

On January 16, 2008, we declared a cash distribution of $0.85 per unit on our outstanding common units. The distribution was paid on February 14, 2008 to unitholders of record on February 4, 2008, for the period October 1, 2007 through December 31, 2007. The total distribution paid was approximately $124 million, with approximately $99 million paid to our common unitholders and $2 million and $23 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Equity Offerings

During the three years ended December 31, 2007, we completed the following equity offerings of our common units (in millions, except per unit data):

	Gross	Proceeds	General Partner	Net

Period	**Units**	**Unit Price**	**from Sale**	**Contribution**	**Costs**	**Proceeds**
June 2007	6,296,172	$ 59.56	$ 375	$ 8	$	$ 383
2007 Total	**6,296,172**		**$ 375**		**$ 8**	$
December 2006(1)	6,163,960	$ 48.67	$ 300	$ 6	$ ( )	$ 306
July/August 2006(1)	3,720,930	$ 43.00	$ 160	$ 3	$	163
March/April 2006(1)	3,504,672	$ 42.80	$ 150	$ 3	$ (1)	152
2006 Total	**13,389,562**		**$ 610**	**$ 12**	**$ (1)**	**$ 621**
September/October 2005(1)	5,854,000	$ 42.00	$ 246	$ 5	$ (9)	$ 242
February 2005(1)	575,000	$ 38.13	$ 22	$ 1	$ (1)	$ 22
2005 Total	**6,429,000**		**$ 268**	**$ 6**	**$ (10)**	**$ 264**

(1) These offerings involved related parties. See Note 9.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 6 Derivatives and Hedging Instruments

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled commodity trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations and delivery schedules to help ensure that our hedging activities address our market risks. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows or the fair value of hedged items.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price-risk hedging activities. Through these activities, we hedge our exposure to price fluctuations with respect to crude oil, LPG, natural gas and refined products as well as with respect to expected purchases, sales and transportation of these commodities. The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to AOCI and recognized in revenues in the periods during which the underlying physical transactions occur. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective, as defined in SFAS 133, in offsetting changes in cash flows of the hedged items, are marked-to-market in revenues each period.

A summary of the earnings impact of all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during 2007, 2006 and 2005 is as follows (in millions, losses designated in brackets):

	For the Year Ended December 31, 2007			For the Year Ended December 31, 2006			For the Year Ended December 31, 2005		
	Mark-to-market, Net	Settled	Total	Mark-to-market, Net	Settled	Total	Mark-to-market, Net	Settled	Total
Commodity price-risk hedging	$ (29)	$ 151	$ 122	$ (3)	$ 113	$ 110	$ (22)	$ 39	$ 17
Controlled trading program		1	1						
Interest rate risk hedging	3	(1)	2		(2)	(2)		(2)	(2)
	2	6	8	(1)	1		3		3

Currency exchange rate risk hedging																		
Total	$	(24)	$	157	$	133	$	(4)	$	112	$	108	$	(19)	$	37	$	18

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The breakdown of the net mark-to-market impact to earnings between derivatives that do not qualify for hedge accounting and the ineffective portion of cash flow hedges is as follows (in millions, losses designated in brackets):

	For the Year Ended December 31,		
	2007	**2006**	**2005**
Derivatives that do not qualify for hedge accounting	$ (23)	$ (5)	$ (18)
Ineffective portion of cash flow hedges	(1)	1	(1)
Total	$ (24)	$ (4)	$ (19)

Derivatives that do not qualify for hedge accounting consist of (i) derivatives that are an effective element of our risk management strategy but are not consistently effective to qualify for hedge accounting pursuant to SFAS 133 and (ii) certain transactions that have not been designated as hedges.

The following table summarizes the net assets and liabilities on our consolidated balance sheet that are related to the fair value of our open derivative positions (in millions):

	December 31,	
	2007	**2006**
Other current assets	$ 56	$ 55
Other long-term assets	26	9
Other current liabilities	(97)	(77)
Long-term debt under credit facilities and other (fair value hedge adjustment)(1)	1	
Other long-term liabilities and deferred credits	(22)	(22)
Net liability	$ (36)	$ (35)

(1) Fair value hedge accounting was discontinued for certain interest rate swaps subsequent to June 30, 2007. The related fair value adjustment to the underlying debt will be amortized over the remaining life of the underlying debt.

The net liability related to the fair value of our open derivative positions consists of unrealized gains/losses recognized in earnings and unrealized gains/losses deferred to AOCI as follows, by category (in millions, losses designated in brackets):

	December 31, 2007			December 31, 2006		
	Net Asset (Liability)	Earnings	AOCI	Net Asset (liability)	Earnings	AOCI
Commodity price-risk hedging	$ (38)	$ (48)	$ 10	$ (33)	$ (19)	$ (14)
Controlled trading program						
Interest rate risk hedging(1)	3	3				
Currency exchange rate risk hedging	(1)		(1)	(2)	(2)	
	$ (36)	$ (45)	$ 9	$ (35)	$ (21)	$ (14)

(1) Amounts are presented on a net basis and include both the net asset/(liability) related to our interest rate swaps and the fair value adjustment related to the underlying debt.

In addition to the $9 million of unrealized gain as of December 31, 2007 and the $14 million of unrealized loss as of December 31, 2006 deferred to AOCI for open derivative positions, AOCI also includes a deferred loss of approximately $5 million and $6 million as of December 31, 2007 and 2006, respectively, that relates to terminated

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interest rate swaps that were cash settled in connection with the issuance and refinancing of debt agreements over the past five years. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the terminated instruments.

The total amount of deferred net gain recorded in AOCI is expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. Of the total net gain deferred in AOCI at December 31, 2007, a net gain of $9 million will be reclassified into earnings in the next twelve months; the remaining net loss will be reclassified at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2010 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions. During the year ended December 31, 2007 and 2006, no amounts were reclassified to earnings from AOCI in connection with forecasted transactions that were no longer considered probable of occurring.

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

Commodity Price-Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil, LPG, refined products, and natural gas, and expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and option contracts traded on the NYMEX, ICE and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. In accordance with SFAS 133, these derivative instruments are recognized on the balance sheet at fair value. The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into AOCI and recognized in revenues or purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133. Physical transactions that are derivatives and are ineligible, or become ineligible, for the normal purchase and sale treatment (e.g. due to changes in settlement provisions) are recorded on the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

At December 31, 2007, the majority of the unrealized losses that have been recognized in earnings relate to the fair value associated with our Canadian and LPG derivative contracts, for which we do not apply hedge accounting treatment as the correlations will tend to fluctuate. These positions primarily consist of hedges of stored inventory and purchase commitments. The loss in the current period primarily results from the impact of rising prices. The unrealized gains deferred in AOCI related to hedges of our lease supply, which are mostly long futures contracts that will result in gains when prices rise. These gains are offset by an increase in the purchase price of our lease contracts and will be reclassed into earnings from AOCI in the same period that the underlying physical barrels are purchased.

At December 31, 2006, the majority of the unrealized losses that were recognized in earnings related to activities associated with our storage assets. In general, revenue from storing crude oil is reduced in a backwardated market (when oil prices for future deliveries are lower than for current deliveries), as there is less incentive to store crude oil from month to month. We enter into derivative contracts that will offset the reduction in revenue by generating offsetting gains in a backwardated market structure. These derivatives do not qualify for hedge accounting because the contracts will not necessarily result in physical delivery. A portion of the net liability as of December 31, 2006 was caused by a reduction in backwardation (a decrease in the amount by which the price of future deliveries is lower than current deliveries) from the time that we entered into the derivative contracts to the end of the year. The net gain or loss related to these instruments will offset storage revenue in the period that the derivative instruments are hedging. The unrealized losses deferred in AOCI related to inventory hedges, which are mostly short derivative positions that will result in losses when prices rise. These hedge losses are offset by an

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

increase in the physical inventory value and will be reclassed into earnings from AOCI in the same period that the underlying physical inventory is sold.

Controlled Trading Program

Although we seek to maintain a position that is substantially balanced within our crude oil lease purchase activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Interest Rate Risk Hedging

During the fourth quarter of 2007, we entered into three treasury locks with large creditworthy financial institutions in anticipation of a debt issuance in 2008. A treasury lock is a financial derivative instrument that enables a company to lock in the U.S. Treasury Note rate. The U.S. Treasury Note rate is the benchmark interest rate for our anticipated debt issuance. The three treasury locks had a combined notional amount of $150 million and an effective interest rate of 4.09%. The treasury locks were designated as cash flow hedges and the changes in fair value of the treasury locks are therefore deferred in AOCI.

In November 2006, in conjunction with the Pacific merger, we assumed interest rate swap agreements with an aggregate notional principal amount of $80 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six month LIBOR plus 1.67% (set in advance or in arrears depending on the swap transaction). The interest rate swaps mature June 15, 2014 and are callable at the same dates and terms as the 7.125% senior notes. These swaps were originally entered into to hedge against changes in the fair value of the 7.125% Senior Notes resulting from market fluctuations to LIBOR. Hedge accounting was discontinued on June 30, 2007. The change in fair value of the interest rate swaps is recorded in earnings each period.

During August 2006, we entered into two treasury locks with large creditworthy financial institutions in anticipation of a debt issuance in conjunction with our acquisition of Pacific. The U.S. Treasury Note rate was the benchmark interest rate for our anticipated debt issuance. The two treasury locks had a combined notional principal amount of $200 million and an effective interest rate of 4.97%. The treasury locks were designated as cash flow hedges and the changes in fair value of the treasury locks were therefore deferred in AOCI. In October 2006, both treasury locks were terminated prior to maturity in connection with the debt issuance in October 2006 for an aggregate cash payment of $2 million.

AOCI includes a deferred loss of approximately $5 million that relates to terminated interest rate swaps and treasury locks that were cash settled in connection with the issuance and refinancing of debt agreements over the past five years. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the forecasted debt instruments.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars and, at times, a portion of our debt is denominated in Canadian dollars, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments may include forward exchange contracts, swaps and

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options. At December 31, 2007, our open foreign exchange derivatives consisted of forward exchange contracts that exchange Canadian dollars (Cdn) and US dollars on a net basis as follows (in millions):

	Canadian Dollars	US Dollars	Average Exchange Rate
2008	$ 9	$ 9	Cdn $ 1.07 to US $1.00
2009	$ 6	$ 6	Cdn $ 1.03 to US $1.00
2010	$ 6	$ 6	Cdn $ 1.03 to US $1.00
2011	$ 6	$ 6	Cdn $ 1.03 to US $1.00
2012	$ 6	$ 6	Cdn $ 1.03 to US $1.00

These financial instruments are placed with large, creditworthy financial institutions.

Fair Value of Financial Instruments

The carrying amount of our derivative financial instruments are recorded on the balance sheet at their fair value under SFAS 133. Our derivative financial instruments currently include: (i) forward exchange contracts for which fair values are based on current liquidation values; (ii) over-the-counter option, swap and forward contracts for which fair values are estimated based on various sources such as independent reporting services, industry publications and brokers; and (iii) NYMEX futures and options for which the fair values are based on quoted market prices. 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.

Note 7 Income Taxes

U.S. Federal and State Taxes

As a master limited partnership, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. In May 2006, the State of Texas enacted a new business tax (the Texas Margin Tax) that replaced its franchise tax. In general, any entity that conducts business in Texas is subject to the Texas Margin Tax. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax because it is determined by applying a tax rate to a base that considers both revenue and expenses. The Texas Margin Tax is effective for returns originally due on or after January 1, 2008. For calendar year end companies such as us, the margin tax is applied to 2007 activity.

Canadian Federal and Provincial Taxes

Certain of our Canadian subsidiaries (acquired through the Pacific merger in 2006) are corporations for Canadian tax purposes, thus their operations are subject to Canadian federal and provincial income taxes. The remainder of our Canadian operations is conducted through an operating limited partnership, which in the past was a flow-through entity for tax purposes. In June 2007, Canadian legislation was passed that imposes entity-level taxes on certain types of flow-through entities. The legislation refers to safe harbor guidelines that grandfather certain existing entities and delay the effective date of such legislation until 2011 provided that the entities do not exceed the normal growth guidelines. Although limited guidance is currently available, we believe that the legislation will apply to our Canadian partnerships. We believe that we are currently within the normal growth guidelines as defined in the legislation, which should delay the effective date for us until 2011. In conjunction with the passage of this legislation, we have recognized a net deferred income tax expense of approximately $10 million for the year ended December 31, 2007. This amount represents the estimated tax effect of temporary differences that exist at December 31, 2007 and are expected to reverse after the date that this legislation is effective for us based on the 28% weighted average tax rate that is expected to be in effect when these temporary differences reverse. Substantially all of this amount is related to differences between book basis and tax basis depreciation on applicable property and

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equipment. If and when facts and circumstances change, we will reassess our position and record adjustments as necessary.

We file income tax returns in Canadian federal and various provincial jurisdictions. Generally, we are no longer subject to Canadian federal and provincial income tax examinations for years before 2004.

Tax Components

Components of the income tax expense are as follows (in millions):

	Year Ended December 31, 2007	Year Ended December 31, 2006
Current tax expense:		
State income tax	$ 1	$
Canadian federal and provincial income tax	2	
Total current tax expense	$ 3	$
Deferred tax expense:		
State income tax	$ 1	$
Canadian federal and provincial income tax	$ 12	
Total deferred tax expense	$ 13	$
Total income tax expense	$ 16	$

The difference between the statutory federal income tax rate and our effective tax expense is summarized as follows (in millions):

	Year Ended December 31, 2007	Year Ended December 31, 2006
Income before tax	$ 381	$ 285
Partnership earnings not subject to Canadian tax	(369)	(285)
	$ 12	$
Canadian federal and provincial corporate tax rate	32.1%	32.5%

Income tax at statutory rate	$	4	$
Canadian corporation deferred tax as a result of book versus tax differences		(2)	
State income tax (Texas Margin Tax; see above)		1	
Current income tax expense	$	3	$
State deferred income tax (Texas Margin Tax; see above)	$	1	$
Canadian corporation deferred tax as a result of book versus tax differences (see above)		2	
Flow-through entities deferred tax as a result of book versus tax differences		10	
Deferred income tax expense	$	13	$
Total income tax expense	$	16	$

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred tax assets and liabilities, which are included within other long-term liabilities and deferred credits in our consolidated balance sheet, result from the following (in millions):

	December 31, 2007	December 31, 2006
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 5	$ 5
Net operating losses carried forward (which expire at various times from 2013 to 2015)	4	3
Total deferred tax assets	9	8
Deferred tax liabilities:		
Canadian partnership income subject to deferral	(4)	(3)
Property, plant and equipment in excess of tax values	(29)	(14)
Total deferred tax liabilities	(33)	(17)
Net deferred tax liabilities	$ (24)	$ (9)

We adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48), an interpretation of SFAS No. 109 Accounting for Income Taxes, on January 1, 2007. The adoption of FIN 48 had no material impact on our financial statements. We recognize interest and penalties related to uncertain tax positions in income tax expense. At December 31, 2007, we have no material assets, liabilities or accrued interest associated with uncertain tax positions.

Note 8 Major Customers and Concentration of Credit Risk

Marathon Petroleum Company, LLC (Marathon) accounted for 19%, 14% and 11% of our revenues for each of the three years ended December 31, 2007, 2006 and 2005. Valero Marketing & Supply Company (Valero) accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 11% of our revenues for the year ended December 31, 2007. BP Oil Supply accounted for 14% of our revenues for the year ended December 31, 2005. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of revenues from these customers 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 is risk, however, that we would not be able to identify and access a replacement market at comparable margins.

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

Note 9 Related Party Transactions

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all direct and indirect costs of services provided to us, incurred on our behalf, including the costs of employee, officer and director compensation and benefits allocable to us, as well as all other expenses necessary or appropriate to the conduct of our business, allocable to us. We record these costs on the accrual basis in the period in which our general partner incurs them. 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. Total costs reimbursed by us to our general partner for the years ended December 31, 2007, 2006 and 2005 were $287 million,

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$205 million and $165 million respectively. Amounts due to our general partner at December 31, 2006 were $1 million. There were no material amounts due to our general partner as of December 31, 2007.

Vulcan Energy Corporation

As of December 31, 2007, Vulcan Energy Corporation (Vulcan Energy) and its affiliates owned approximately 54% of our general partner interest, as well as approximately 11% 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.

Another owner of Plains All American GP LLC, Lynx Holdings I, LLC, agreed to restrict certain of its voting rights with respect to its approximate 1.2% membership interest in Plains All American GP LLC.

Administrative Services Agreement. On October 14, 2005, Plains All American GP LLC (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 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.

Omnibus Agreement. PAA, GP LLC, certain affiliated entities and Vulcan Energy are parties to an amended and restated omnibus agreement dated as of July 23, 2004. Pursuant to this agreement, Vulcan Energy has agreed, so long as Vulcan Energy or any of its affiliates owns an interest, directly or indirectly, in GP LLC, not to engage in or acquire any business engaged in the following activities:

- crude oil storage, terminalling and gathering activities in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than entities affiliated with Vulcan Energy and its affiliates (collectively, the Vulcan entities) or GP LLC, PAA, its operating partnerships and any controlled affiliates (collectively, the Plains entities);

- crude oil marketing activities; and

transportation of crude oil by pipeline in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than the Plains entities.

These restrictions are subject to specified permitted exceptions and may be terminated by Vulcan Energy upon certain change of control events involving Vulcan Energy. The omnibus agreement further permits, except as otherwise restricted by the omnibus agreement or any other agreement, each Vulcan entity to engage in any business activity, including those that may be in direct competition with the Plains entities. Further, any owner of equity interests in Vulcan Energy may make passive investments in PAA s competitors so long as such owner does not

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directly or indirectly use any knowledge or confidential information it received through the ownership by a Plains entity to compete, or to engage in or become interested financially in any person that competes, in the restricted activities described above.

Crude Oil Purchases from Calumet Florida L.L.C. Prior to August 2005, Vulcan Energy owned 100% of Calumet Florida L.L.C. (Calumet). From August 2005 to May 2007, Calumet was owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. In May 2007, Calumet was sold and ceased to be related to Vulcan Energy. In 2007, until the date that Calumet ceased to be related to Vulcan Energy, we purchased crude oil from Calumet for approximately $17 million. We purchased crude oil from Calumet and paid approximately $45 million and $38 million to Calumet in 2006 and 2005, respectively.

Investment in PAA/Vulcan Gas Storage, LLC

PAA/Vulcan, a limited liability company, was formed in 2005. PAA/Vulcan is owned 50% by us and the other 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan Capital, which is an affiliate of Vulcan Energy. Mr. David Capobianco, a member of our Board of Directors, holds a profits interest in Vulcan Gas Storage LLC. The Board of Directors of PAA/Vulcan is comprised of an equal number of our representatives and representatives of Vulcan Gas Storage and is responsible for providing strategic direction and policy-making. We are responsible for the day-to-day operations. PAA/Vulcan is not a variable interest entity, and we do not have the ability to control the entity; therefore, we account for the investment under the equity method in accordance with APB 18. This investment is reflected in investments in unconsolidated entities in our consolidated balance sheet.

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 $113 million, and Bluewater Natural Gas Holdings, LLC, a subsidiary of PAA/Vulcan (Bluewater) entered into a $90 million credit facility contemporaneously with closing. In August 2006, the borrowing capacity under this facility was increased to $120 million. 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 2008, 2009 and 2010. We recorded deferred revenue for receipt of a one-time 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. During 2007, we contributed an additional $9 million to PAA/Vulcan. This contribution did not result in an increase to our ownership interest.

In conjunction with the 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

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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 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 million, we will receive a distribution from PAA/Vulcan equal to $6 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.

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 Kayne Anderson Capital Advisors, L.P. (KACALP) and Encap Investments, L.P., respectively. The net proceeds were used to fund capital expenditures, to reduce indebtedness and for general partnership purposes. KAFU Holdings, L.P. (which is managed by KACALP) and an affiliate of Encap each have a representative on our board of directors.

In July and August 2006, we sold a total of 3,720,930 common units, approximately 19% and 13% of which were sold to investment funds affiliated with Vulcan Capital and KACALP, respectively. The proceeds from this offering were used to fund acquisition costs, repay indebtedness under our credit facility and for general partnership purposes. Vulcan Capital has a representative on our board of directors.

In March and April 2006, we sold 3,504,672 common units, approximately 20% of which were sold to investment funds affiliated with KACALP. The net proceeds were used to fund a portion of the Andrews acquisition, to reduce indebtedness and for general partnership purposes.

Concurrently with our public offering of equity in September 2005, 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 3% discount to the closing price of the units on February 24, 2005. The sale resulted in net proceeds, including the general partner s proportionate capital contribution ($1 million) and net of expenses associated with the sale, of approximately $22 million.

Note 10 Equity Compensation Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the 1998 Plan), the 2005 Long-Term Incentive Plan (the 2005 Plan) and the PPX Successor Long-Term Incentive Plan (the PPX Successor Plan) for employees and directors as well as the Plains All American GP LLC 2006 Long-

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Term Incentive Tracking Unit Plan (the 2006 Plan) for non-officer employees. The 1998 Plan, 2005 Plan and PPX Successor Plan authorize the grant of an aggregate of 5.4 common units deliverable upon vesting. Although other types of awards are contemplated under the plans, currently outstanding awards are limited to phantom units, which mature into the right to receive common units (or cash equivalent) upon vesting. Some awards also include distribution equivalent rights (DERs). Subject to applicable earning criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit. The 2006 Plan authorizes the grant of approximately 1.4 million tracking units which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a common unit at the time of vesting. Our general partner will be entitled to reimbursement by us for any costs incurred in settling obligations under the plans.

Under SFAS 123(R) the fair value of our LTIP awards, which are subject to liability classification, is calculated based on the closing market price of our units at each balance sheet date adjusted for (i) the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipients and (ii) an estimated forfeiture rate when appropriate. This fair value is recognized as compensation expense over the period the awards are earned. Our LTIP awards typically contain performance conditions based on attainment of certain annualized distribution levels and vest upon the later of a certain date or the attainment of such levels. For awards with performance conditions, we recognize compensation expense only if the achievement of the performance condition is considered probable and amortize that expense over the service period. When awards with performance conditions that were previously considered improbable of occurring become probable of occurring, we incur additional LTIP compensation expense necessary to adjust the life-to-date accrued liability associated with these awards. Our DER awards typically contain performance conditions based on the attainment of certain annualized distribution levels and become earned upon the earlier of a certain date or the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. We recognize compensation expense for DER payments in the period the payment is earned.

At December 31, 2007 we have the following LTIP awards outstanding (units in millions):

LTIP Units Outstanding	Vesting Distribution Amount	Unit Vesting Date 2008	2009	2010	2011	2012
1.3[1]	$ 3.20	0.1	0.6	0.6		
1.3[2]	$ 3.50 - $4.00		0.1	0.1	0.7	0.4
1.0[3]	$ 3.50 - $4.00			1.0		
3.6[4][5]		0.1	0.7	1.7	0.7	0.4

(1) Upon our February 2007 annualized distribution of $3.20, these LTIP awards satisfied all distribution requirements and will vest upon completion of the respective service period.

(2)

These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between \$3.50 and \$4.00 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained, these awards will be forfeited. The awards are presented above assuming the distribution levels are attained prior to the end of the service period.

(3) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between \$3.50 and \$4.00. Fifty percent of these awards will vest in 2012 regardless of whether the performance conditions are attained. The awards are presented above assuming the distribution levels are attained and the early vesting requirements are met.

(4) Approximately 2.1 million of our approximately 3.6 million outstanding LTIP awards also include DERs, of which 1.0 million are currently earned.

(5) LTIP units outstanding do not include Class B units

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Our LTIP activity is summarized in the following table (in millions, except weighted average grant date fair values per unit):

	Year Ended December 31,					
	2007		2006		2005	
	Units	Weighted Average Grant Date Fair Value	Units	Weighted Average Grant Date Fair Value	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	3.0	$ 31.94	2.2	$ 34.37	0.1	$ 23.40
Granted	1.6	47.25	0.9	26.00	2.2	34.41
Vested	(0.7)	34.86			(0.1)	22.42
Cancelled or forfeited	(0.3)	36.00	(0.1)	33.05		
Outstanding at end of period	3.6	$ 37.75	3.0	$ 31.94	2.2	$ 34.37

Our accrued liability at December 31, 2007 related to all outstanding LTIP awards and DERs is approximately $51 million, which includes an accrual associated with our assessment that an annualized distribution of $3.50 is probable of occurring. We have not deemed a distribution of more than $3.50 to be probable. At December 31, 2006, the accrued liability was approximately $58 million.

GP Class B Units

In August 2007, the owners of Plains AAP, L.P. authorized the creation and issuance of up to 200,000 Class B units of Plains AAP, L.P. to be administered by the compensation committee. At December 31, 2007, approximately 154,000 Class B units have been granted and the remaining units are reserved for future grants. The Class B units are earned in 25% increments upon us achieving annualized distribution levels of $3.50, $3.75, $4.00 and $4.50 (or in some cases, within six months thereof). When earned, the Class B units are entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million per quarter. Assuming all 200,000 Class B units were granted and earned, the maximum participation would be 8% of Plains AAP, L.P. s distribution in excess of $11 million each quarter. Although the entire economic burden of the Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding, the intent of the Class B units is to provide a performance incentive and encourage retention for certain members of our senior management. Therefore, we recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to Partners Capital in our Consolidated Financial Statements. The total grant date fair value of the 154,000 Class B units outstanding at December 31, 2007 was approximately $34 million, of which approximately $3 million was recognized as expense during the twelve months ended December 31, 2007.

Other Consolidated Information

We refer to our LTIP Plans and the Class B units collectively as Equity compensation plans. The table below summarizes the expense recognized and the value of vestings (settled both in units and cash) related to the equity compensation plans (in millions):

	Twelve Months Ended December 31,		
	2007	**2006**	**2005**
Equity compensation expense	$ 49	$ 43	$ 26
LTIP unit vestings	$ 17	$ 1	$ 4
LTIP cash settled vestings	$ 16	$ 2	$ 4
DER cash payments	$ 4	$ 3	$ 1

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Approximately 0.3 million units were issued in 2007 in connection with the settlement of vested awards. The remaining 0.4 million of awards that vested during 2007 were settled in cash. There was an insignificant amount of units issued in connection with the settlement of vested awards in 2006 and 2005. As of December 31, 2007, the weighted average remaining contractual life of our outstanding LTIP awards was approximately three years based on expected vesting dates. Based on the December 31, 2007 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $67 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value. This estimate is based on the closing market price of our units of $52.00 at December 31, 2007. Actual amounts may differ materially as a result of a change in the market price of our units and/or probability assessment regarding future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	Equity Compensation Plan Fair Value Amortization(1)	
2008	$	31
2009		19
2010		11
2011		4
2012		2
Total	$	67

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at December 31, 2007.

Note 11 Commitments and Contingencies

Commitments

We lease certain real property, equipment and operating facilities under various operating and capital leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancellable commitments related to these items at December 31, 2007, are summarized below (in millions):

2008	$	45
2009	$	40
2010	$	28
2011	$	20
2012	$	16

Thereafter	$ 142
Total	$ 291

Expenditures related to leases for 2007, 2006 and 2005 were $51 million, $38 million and $26 million, respectively.

Contingencies

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

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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 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 $4 million to $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 civil penalty enforcement action under the Federal Clean Water Act. We have cooperated in the investigation and are currently involved in settlement discussions with DOJ and EPA. Our assessment is that it is probable we will pay penalties related to the two releases. We may also be subjected to injunctive remedies that would impose additional requirements and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency, which is included in the estimated aggregate costs set forth above. We understand that the maximum permissible penalty, if any, that EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. We believe that several mitigating circumstances and factors exist that are likely to substantially reduce any penalty that might be imposed by EPA, and will continue to engage in discussions with EPA and the DOJ with respect to such mitigating circumstances and factors, as well as any injunctive remedies proposed.

On November 15, 2006, we completed the Pacific merger. 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. Total projected emergency response, remediation and restoration costs are approximately $26 million, substantially all of which have been incurred. We anticipate that the majority of costs associated with this release will be covered under a pre-existing PPS pollution liability insurance policy. Substantially all of the costs that were incurred as of December 31, 2007 have been recovered under the 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, if any, that can be assessed is estimated to be approximately $1.4 million, in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of crude oil recovered and the State of California has the discretion to further reduce the fine, if any, 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 alleged 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 any natural resource damages amount. We believe that the alleged violations are without merit and intend to defend against them, and that defenses and mitigating factors should apply. We are in settlement discussions with the State of California.

The EPA has referred this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. We understand that the maximum permissible penalty, if any, that the EPA could assess under relevant statutes would be approximately $4.2 million. We believe that several defenses and mitigating circumstances and factors

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exist that could substantially reduce any penalty that might be imposed by the EPA, and intend to pursue discussions with the EPA regarding such defenses and mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be claimed by the EPA cannot be ascertained. While we have established an estimated loss contingency for this matter, we are presently unable to determine whether the March 2005 spill incident may result in a loss in excess of our accrual for this matter. Discussions with the DOJ to resolve this matter have commenced.

Pacific Atlantic Terminals. 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 various locations, including northern California, the Philadelphia, Pennsylvania metropolitan area and Paulsboro, New Jersey. In the process of integrating PAT s assets into our operations, we identified certain aspects of the operations at the California 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 have cooperated with the District s review of these matters. Although we are currently unable to determine the outcome of the foregoing, at this time, we do not believe it will have a material impact on our financial condition, results of operations or cash flows.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE contamination at PAT s facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to $12 million. Both Exxon and GATX were prior owners of the terminal. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific s purchase of the facility. In a related matter, the New Jersey Department of Environmental Protection has brought suit against GATX and Exxon to recover natural resources damages. Exxon and GATX have filed third-party demands against PAT, seeking indemnity and contribution. We intend to vigorously defend against any claim that PAT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in the imposition of fines and penalties. For example, we were informed by the EPA that a terminal owned by Rocky Mountain Pipeline Systems LLC (RMPS), one of the subsidiaries acquired in the Pacific merger, was purportedly out of compliance with certain regulatory documentation requirements. Upon review, we found similar issues at other RMPS terminals. We have settled these matters with EPA.

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.

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil 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 help prevent releases, 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 procedures, remove selected assets from service and spend capital to upgrade the assets. However, the inclusion of additional miles of pipe in our operations 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 purchase of assets from Link Energy LLC in April 2004,

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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, including a Section 308 request received in late October 2007 with respect to a 400-barrel release of crude oil, a portion of which reached a tributary of the Colorado River in a remote area of West Texas.

At December 31, 2007, our reserve for environmental liabilities totaled approximately $36 million, of which approximately $15 million is classified as short-term and $21 million is classified as long-term. At December 31, 2007, we have recorded receivables totaling approximately $7 million for amounts that are probable of recovery 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, costs incurred in excess of this reserve may be higher and may potentially have a material adverse effect on our financial condition, results of operations, or cash flows.

Other. A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our environmental activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 12 Supplemental Condensed Consolidating Financial Information

In conjunction with the Pacific acquisition, some but not all of our 100% owned subsidiaries have issued full, unconditional, and joint and several guarantees of our Senior Notes. Given that certain, but not all, subsidiaries are guarantors of our Senior Notes, we are required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote:

we are referred to as Parent;

the Guarantor Subsidiaries are PAA Finance Corp.; Plains Marketing, L.P.; Plains Pipeline, L.P.; Plains Marketing GP Inc.; Plains Marketing Canada LLC; Plains Marketing Canada, L.P.; PMC (Nova Scotia)

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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; PICSCO LLC; Plains Marketing International, L.P; Plains LPG Marketing, L.P.; Rocky Mountain Pipeline System, LLC; Pacific Marketing and Transportation LLC; Pacific Atlantic Terminals LLC; Pacific LA Marine Terminal, LLC; Ranch Pipeline LLC; PEG Canada GP LLC; PEG Canada, L.P.; Pacific Energy Group LLC; Pacific Energy Finance Corporation; Rangeland Pipeline Company (RPC); Rangeland Marketing Company (RMC); Rangeland Northern Pipeline Company (RNPC); Rangeland Pipeline Partnership (RPP); and Aurora Pipeline Company, Ltd.; and

Non-Guarantor Subsidiaries are Atchafalaya Pipeline, L.L.C. (which ceased to exist and was merged into Plains Pipeline, L.P. during 2007, and consequently ceased to be a non-guarantor subsidiary); Andrews Partners, LLC; Pacific Pipeline System, LLC, Pacific Terminals, LLC, Pacific Energy Management LLC, Pacific Energy GP LP, Plains Towing LLC and SLC Pipeline LLC.

Subsequent to December 31, 2007, the assets and liabilities of RMC, RPC and RNPC were conveyed to and assumed by Plains Midstream Canada ULC. Plains Midstream Canada ULC, Plains Midstream, L.P., Plains Midstream GP LLC and Plains Towing LLC became Guarantor Subsidiaries, and PEG Canada GP LLC, PEG Canada, L.P., RPC, RMC, RNPC and RPP ceased to be the Guarantor Subsidiaries.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following supplemental condensed consolidating financial information reflects the Parent s separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Parent s Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent s investments in its subsidiaries and the Guarantor Subsidiaries investments in their subsidiaries are accounted for under the equity method of accounting (all amounts in millions):

Condensed Consolidating Balance Sheet

	As of December 31, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,277	$ 3,858	$ 91	$ (2,553)	$ 3,673
Property plant and equipment, net		3,791	628		4,419
Other assets:					
Investment in unconsolidated entities	3,881	863		(4,529)	215
Other assets	22	1,259	318		1,599
Total assets	$ 6,180	$ 9,771	$ 1,037	$ (7,082)	$ 9,906
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 134	$ 5,911	$ 237	$ (2,553)	$ 3,729
Other liabilities:					
Long-term debt	2,622	2			2,624
Other long-term liabilities		128	1		129
Total liabilities	2,756	6,041	238	(2,553)	6,482
Partners Capital	3,424	3,730	799	(4,529)	3,424
Total liabilities and partners capital	$ 6,180	$ 9,771	$ 1,037	$ (7,082)	$ 9,906

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	As of December 31, 2006				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,574	$ 3,049	$ 97	$ (2,563)	$ 3,157
Property plant and equipment, net		3,227	615		3,842
Other assets:					
Investment in unconsolidated entities	3,038	731		(3,586)	183
Other assets	23	1,198	312		1,533
Total assets	$ 5,635	$ 8,205	$ 1,024	$ (6,149)	$ 8,715
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 35	$ 5,356	$ 14	$ (2,380)	3,025
Other liabilities:					
Long-term debt	2,623	(274)	277		2,626
Other long-term liabilities		85	2		87
Total liabilities	2,658	5,167	293	(2,380)	5,738
Partners Capital	2,977	3,038	731	(3,769)	2,977
Total liabilities and partners capital	$ 5,635	$ 8,205	$ 1,024	$ (6,149)	$ 8,715

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Consolidating Statements of Operations

	Year Ended December 31, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries (In millions)	Eliminations	Consolidated
Net operating revenues(1)	$	$ 1,271	$ 122	$	$ 1,393
Field operating costs		(493)	(38)		(531)
General and administrative expenses		(161)	(3)		(164)
Depreciation and amortization	(3)	(157)	(20)		(180)
Operating income (loss)	(3)	460	61		518
Equity earnings in unconsolidated entities	524	66		(575)	15
Interest expense	(161)	(1)			(162)
Interest income and other income (expense), net	5	5			10
Income tax expense		(16)			(16)
Net income (loss)	$ 365	$ 514	$ 61	$ (575)	$ 365

	Year Ended December 31, 2006				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues(1)	$	$ 955	$ 16	$	$ 971
Field operating costs		(376)	(6)		(382)
General and administrative expenses		(133)	(1)		(134)
Depreciation and amortization	(3)	(94)	(3)		(100)
Operating income (loss)	(3)	352	6		355
Equity earnings in unconsolidated entities	363	14		(369)	8
Interest expense	(77)	(9)			(86)
Interest income and other income (expense), net	2				2

Income before cumulative effect of change in accounting principle		285		357		6		(369)		279
Cumulative effect of change in accounting principle				6						6
Net income (loss)	$	285	$	363	$	6	$	(369)	$	285

(1) Net operating revenues are calculated as Total revenues less Crude oil, refined products and LPG purchases and related costs.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 365	$ 514	$ 61	$ (575)	$ 365
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	3	157	20		180
SFAS 133 mark-to-market adjustment	2	22			24
Inventory valulation adjustment		1			1
Gain on sale of investment assets		(4)			(4)
Gain on sale of linefill		(12)			(12)
Equity compensation charge		49			49
Income tax expense		16			16
Noncash amortization of terminated interest rate hedging instruments		1			1
Equity earnings in unconsolidated entities, net of distributions	(524)	(65)		575	(14)
Changes in assets and liabilities, net of acquisitions:	230	17	(57)		190
Net cash provided by operating activities	76	696	24		796
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions (Note 3)		(127)			(127)
Additions to property and equipment		(524)	(24)		(548)
Investment in unconsolidated entities	(9)				(9)
Cash paid for linefill in assets owned		(19)			(19)
Proceeds from sales of assets		40			40
Net cash used in investing activities	(9)	(630)	(24)		(663)
CASH FLOWS FROM FINANCING ACTIVITIES					
		305			305

Net borrowings/(repayments) on working capital revolving credit facility					
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility		(359)			(359)
Net proceeds from the issuance of common unitholders (Note 5)	383				383
Distributions paid to common unitholders (Note 5)	(370)				(370)
Distributions paid to general partner (Note 5)	(81)				(81)
Other financing activities		(2)			(2)
Net cash provided by financing activities	(68)	(56)			(124)
Effect of translation adjustment on cash		4			4
Net increase (decrease) in cash and cash equivalents	(1)	14			13
Cash and cash equivalents, beginning of period	2	9			11
Cash and cash equivalents, end of period	$ 1	$ 23	$	$	$ 24

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2006				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 285	$ 363	$ 6	$ (369)	$ 285
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	3	94	3		100
Cumulative effect of change in accounting principle		(6)			(6)
Inventory valuation adjustment		6			6
SFAS 133 mark-to-market adjustment		4			4
Equity compensation charge		43			43
Noncash amortization of terminated interest rate hedging instruments	2				2
Loss on foreign currency revaluation		4			4
Net cash paid for terminated interest rate hedging instruments	(2)				(2)
Equity earnings in unconsolidated entities	(362)	(14)		369	(7)
Net change in assets and liabilities, net of acquisitions	(493)	(158)	(8)	(46)	(705)
Net cash provided by (used in) operating activities	(567)	336	1	(46)	(276)
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of $20 cash assumed from acquisitions	(704)	(560)			(1,264)
Additions to property and equipment		(340)	(1)		(341)
Investment in unconsolidated entities	(46)	(46)		46	(46)
Cash paid for linefill in assets owned		(4)			(4)
Proceeds from sales of assets		4			4
Net cash used in investing activities	(750)	(946)	(1)	46	(1,651)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net (repayments) on long-term revolving credit facility	(291)	(8)			(299)

Net borrowings on working capital revolving credit facility		3			3
Net borrowings on short-term letter of credit and hedged inventory facility		616			616
Proceeds from the issuance of senior notes	1,243				1,243
Net proceeds from the issuance of common units	643				643
Distributions paid to unitholders and general partner	(263)				(263)
Other financing activities	(13)	(3)			(16)
Net cash provided by financing activities	1,319	608			1,927
Effect of translation adjustment on cash		1			1
Net increase (decrease) in cash and cash equivalents	2	(1)			1
Cash and cash equivalents, beginning of period		10			10
Cash and cash equivalents, end of period	$ 2	$ 9	$	$	$ 11

At December 31, 2005 and for the year ended December 31, 2005, the Non-Guarantor Subsidiaries were considered minor, as defined by Regulation S-X rule 3-10(h)(6) and thus, supplemental condensed consolidating financial information is not presented for that period.

Note 13 Environmental Remediation

We currently own or lease properties where hazardous liquids, including hydrocarbons, are or have been handled. These properties and the hazardous liquids or associated 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 wastes (including wastes

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 environmental risk 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 sites requiring remediation that 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, 2007, we had incurred approximately $11 million of remediation costs associated with these sites; SOP s share is approximately $3 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.

In connection with our 1999 acquisition of Scurlock Permian LLC from Marathon Ashland Petroleum (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 Note 11). 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 million. The remediation obligation for certain sites, such as at the products terminal at Paulsboro, New Jersey, is being contested. See Note 11.

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. See Note 11.

At December 31, 2007, our reserve for environmental liabilities totaled approximately $36 million, of which approximately $15 million is classified as short-term and $21 million is classified as long-term. At December 31, 2007, we have recorded receivables totaling approximately $7 million for amounts that are probable of recovery 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, costs incurred in excess of this reserve may be higher and may potentially have a material adverse effect on our financial condition, results of operations, or cash flows.

Note 14 Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total(1)
		(In millions, except per unit data)			
2007					
Revenues(2)	$ 4,230	$ 3,918	$ 5,799	$ 6,447	$ 20,394
Gross margin(3)	164	200	168	150	682
Operating income	118	153	134	114	518
Net income	85	105	98	77	365
Basic net income per limited partner unit	0.62	0.78	0.66	0.48	2.54
Diluted net income per limited partner unit	0.61	0.78	0.66	0.47	2.52
Cash distributions per common unit(4)	$ 0.800	$ 0.813	$ 0.830	$ 0.840	$ 3.28
2006					
Revenues(2)	$ 8,635	$ 4,892	$ 4,526	$ 4,392	$ 22,445
Gross margin(3)	104	124	146	115	489
Operating income	72	97	113	73	355
Cumulative change in accounting principle	6				6
Net income	63	80	95	46	285
Basic net income per limited partner unit	0.73	0.82	0.90	0.37	2.91
Diluted net income per limited partner unit	0.71	0.81	0.89	0.36	2.88
Cash distributions per common unit(4)	$ 0.688	$ 0.708	$ 0.725	$ 0.750	$ 2.87

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

(2) Includes buy/sell transactions. See Note 2.

(3) Gross margin is calculated as Total revenues less (i) Crude oil, refined products and LPG purchases and related costs, (ii) Field operating costs and (iii) Depreciation and amortization.

(4) Represents cash distributions declared and paid in the applicable period.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15 Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities 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. 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. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which acts to partially offset the wear and tear and age-related decline in the value of our principal fixed assets. These maintenance investments 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, not maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life, improve the efficiency of the asset, or expand the operating capacity are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (in millions).

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Transportation		Facilities		Marketing		Total	
			(in millions)					
Twelve Months Ended December 31, 2007(1)								
Revenues:								
External Customers	$	439	$	121	$	19,834	$	20,394
Intersegment(2)		332		89		24		445
Total revenues of reportable segments	$	771	$	210	$	19,858	$	20,839
Equity in earnings of unconsolidated entities	$	5	$	10	$		$	15
Segment profit(1)(3)(4)	$	334	$	110	$	269	$	713
Capital expenditures	$	255	$	348	$	47	$	650
Total assets	$	4,896	$	1,042	$	3,968	$	9,906
SFAS 133 impact(1)	$		$		$	(27)	$	(27)
Maintenance capital	$	34	$	10	$	6	$	50
Twelve Months Ended December 31, 2006(1)								
Revenues:								
External Customers (includes buy/sell revenues of $0, $0, and $4,762, respectively)(1)	$	344	$	41	$	22,060	$	22,445
Intersegment(2)		190		47		1		238
Total revenues of reportable segments	$	534	$	88	$	22,061	$	22,683
Equity in earnings of unconsolidated entities	$	2	$	6	$		$	8
Segment profit(1)(3)(4)	$	200	$	35	$	228	$	463
Capital expenditures	$	1,957	$	1,323	$	73	$	3,353
Total assets	$	3,793	$	1,333	$	3,589	$	8,715
SFAS 133 impact(1)	$		$		$	(4)	$	(4)
Maintenance capital	$	20	$	5	$	3	$	28
Twelve Months Ended December 31, 2005(1)								

Revenues:								
External Customers (includes buy/sell revenues of $0, $0, and $16,275, respectively)(1)	$	270	$	14	$	30,892	$	31,176
Intersegment(2)		165		28		1		194
Total revenues of reportable segments	$	435	$	42	$	30,893	$	31,370
Equity in earnings of unconsolidated entities	$	1	$	1	$		$	2
Segment profit(1)(3)(4)	$	170	$	15	$	175	$	360
Capital expenditures	$	111	$	58	$	20	$	189
Total assets	$	1,859	$	142	$	2,119	$	4,120
SFAS 133 impact(1)	$		$		$	(19)	$	(19)
Maintenance capital	$	9	$	1	$	4	$	14

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

(2) Intersegment sales are conducted at arms length.

(3) Marketing segment profit includes interest expense on contango inventory purchases of $44 million, $49 million, and $24 million for the twelve months ended December 31, 2007, 2006 and 2005, respectively.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Segment profit	$ 713	$ 463	$ 360
Depreciation and amortization	(180)	(100)	(84)
Interest expense	(162)	(86)	(59)
Interest income and other income (expense), net	10	2	1
Income tax expense	(16)		
Income before cumulative effect of change in accounting principle	$ 365	$ 279	$ 218

Geographic Data

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

	For the Year Ended December 31,		
	2007	**2006**	**2005**
Revenues(1)			
United States (includes buy/sell revenues of $0, $4,170, and $14,749, respectively)	$ 13,372	$ 18,119	$ 26,199
Canada (includes buy/sell revenues of $0, $592, and $1,526, respectively)	7,022	4,326	4,977
	$ 20,394	$ 22,445	$ 31,176

(1) Revenues are attributed to each region based on where the customers are located.

	For the Year Ended December 31,	
	2007	**2006**
Long-Lived Assets		
United States	$ 5,407	$ 4,948

Canada	800	600
	$ 6,207	$ 5,548

EXHIBIT INDEX

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 the Current Report on 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 File No. 333-138888).
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 File No. 333-138888).
3.7	Third Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed January 4, 2008).
3.8	Fourth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 28, 2007 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed January 4, 2008).
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 (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.11	Bylaws of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	Amendment No. 3 dated August 16, 2007 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 August 22, 2007).
3.13	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (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, as trustee (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, as trustee (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, as trustee (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4 filed December 10, 2004, 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, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4 filed December 10, 2004, File No. 333-121168).
4.6	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, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.7	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated as of May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein 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).
4.8	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., the Subsidiary Guarantors named therein 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).
4.9	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., the Subsidiary Guarantors named therein 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).
4.10	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., the Subsidiary Guarantors named therein 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).
4.11	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., the Subsidiary Guarantors named therein 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).
4.12	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., the Subsidiary Guarantors named therein 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).
4.13	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 Energy Partners, L.P. s Quarterly Report on Form 10-Q for the quarter

	ended June 30, 2004).
4.14	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 Energy Partners, L.P. s Current Report on Form 8-K filed March 9, 2005).

4.15	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 (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.16	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, the Guarantors named therein 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).
4.17	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 6 1/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed September 28, 2005).
4.18	First Supplemental Indenture dated November 15, 2006 to Indenture dated as of September 23, 2005, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.19	Registration Rights Agreement dated as of July 26, 2006 among Plains All American Pipeline, L.P., Vulcan Capital Private Equity I LLC, Kayne Anderson MLP Investment Company and Kayne Anderson Energy Total Return Fund, Inc. (incorporated by reference to Exhibit 4.13 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.20	Registration Rights Agreement dated as of December 19, 2006 among Plains All American Pipeline, L.P., E-Holdings III, L.P., E-Holdings V, L.P., Kayne Anderson MLP Investment Company and Kayne Anderson Energy Development Company (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-3/A filed December 21, 2006, File No. 333-138888).
4.21	Twelfth Supplemental Indenture dated January 1, 2008 to Indenture dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee.
4.22	Second Supplemental Indenture dated January 1, 2008 to Indenture dated as of September 23, 2005, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.23	Fourth Supplemental Indenture dated January 1, 2008 to Indenture dated as of June 16, 2004, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee.
10.1	Second Amended and Restated Credit Agreement dated as of July 31, 2006 by and among Plains All American Pipeline, L.P., as US Borrower; PMC (Nova Scotia) Company and Plains Marketing Canada, L.P., as Canadian Borrowers; Bank of America, N.A., as Administrative Agent; Bank of America, N.A., acting through its Canada Branch, as Canadian Administrative Agent; Wachovia Bank, National Association and JPMorgan Chase Bank, N.A., as Co-Syndication Agents; Fortis Capital Corp., Citibank, N.A., BNP Paribas, UBS Securities LLC, SunTrust Bank, and The Bank of Nova Scotia, as Co-Documentation Agents; the Lenders party thereto; and Banc of America Securities LLC

	and Wachovia Capital Markets, LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 4, 2006).
10.2	Restated Credit Facility (Uncommitted Senior Secured Discretionary Contango Facility) dated November 19, 2004 among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 24, 2004).

10.3	Amended and Restated Crude Oil Marketing Agreement dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.4	Amended and Restated Omnibus Agreement dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.5	Contribution, Assignment and Amendment Agreement dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 27, 2001).
10.6	Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2001).
10.7	Separation Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed June 11, 2001).
10.8**	Pension and Employee Benefits Assumption and Transition Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed June 11, 2001).
10.9**	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005).
10.10**	Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.11**	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-8 filed December 11, 2001, File No. 333-74920).
10.12**	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13**	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.14	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed May 10, 2001).
10.15	Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.16	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).

10.17	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.18	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998).

10.19**	Plains All American Inc. 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.20**	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004).
10.21**	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.22**	Directors Compensation Summary.
10.23	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2001).
10.24**	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.25**	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005).
10.26**	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005).
10.27**	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005).
10.28**	Form of LTIP Grant Letter (payment to entity) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed February 23, 2005).
10.29**	Form of Performance Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005).
10.30	Administrative Services Agreement between Plains All American GP LLC and Vulcan Energy Corporation dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005).
10.31	Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC dated September 13, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed September 19, 2005).
10.32	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005).
10.33**	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 16, 2005).
10.34**	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 16, 2005).
10.35	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005).
10.36	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005).
10.37	First Amendment dated as of April 20, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 21, 2005).

10.38	Second Amendment dated as of May 20, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed May 12, 2005).
10.39**	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2005).

10.40**	Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.41	Third Amendment dated as of November 4, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.41 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.42	Fourth Amendment dated as of November 16, 2006 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.42 to the Annual Report on Form 10-K for the year ended December 31, 2006.
10.43	First Amendment dated May 9, 2006 to the Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC dated September 13, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed May 15, 2006).
10.44**	Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 23, 2006).
10.45**	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to the Annual Report on Form 10-K for the year ended December 31, 2006).
10.46**	Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.47	Joinder and Supplement dated effective June 20, 2007 among the Lenders party thereto, related to the Restated Credit Agreement dated November 19, 2004, as amended (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).
10.48	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] by and between Plains All American Pipeline, L.P., PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Rangeland Pipeline Company, Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).
10.49**	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R. Coiner (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.50**	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 4, 2008).
10.51	Fifth Amendment to Restated Credit Agreement dated as of November 16, 2007, by and among Plains Marketing, L.P., Plains All American Pipeline, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 21, 2007).
10.52	Guaranty by Plains All American Pipeline, L.P. dated November 16, 2007 in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed November 21, 2007).
10.53	Contribution and Assumption Agreement, dated December 28, 2007, by and between Plains AAP, L.P. and PAA GP LLC (incorporated by reference to Exhibit 10.2 to the Current Report filed January 4, 2008).

10.54	Assumption, Ratification and Confirmation Agreement dated January 1, 2008 by Plains Midstream Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended.
21.1	List of Subsidiaries of Plains All American Pipeline, L.P..
23.1	Consent of PricewaterhouseCoopers LLP.
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).

31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350

Filed herewith

** Management compensatory plan or arrangement