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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

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 (State or other jurisdiction of incorporation or organization)	**76-0582150** (I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas (Address of principal executive offices)	**77002** (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 ☒ 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 ☒

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

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

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

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 $4.9 billion on June 30, 2008, based on $45.11 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 20, 2009, there were outstanding 122,911,645 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K—2008 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" and "forecast," as well as 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;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- the success of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- 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, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;
- 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 ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the 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, governmental regulations, accounting standards and statements and related interpretations;
- the effects of competition;
- 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;
- future developments and circumstances at the time distributions are declared;
- general economic, market or business conditions and the amplification of other risks caused by deteriorated financial markets, capital constraints and pervasive liquidity concerns; 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 the context indicates otherwise.

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

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 manage and 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 may also 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, gains and losses from derivative activities and selected items that are generally unusual or non-recurring); 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. NYMEX is part of CME Group Inc. and is referred to as NYMEX throughout this document.

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, 2008 and for the year then ended, we were in line with our targeted metrics.

Credit Rating

As of February 2009, 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 rating agencies. Note that a credit rating is not a recommendation to buy, sell or hold securities, and may be revised or withdrawn at any time. See Item 1A. "Risk Factors—Risks Related to Our Business—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" for discussion of the potential impacts of a downgrade in our credit ratings.

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 eleven years, we have completed and integrated approximately 52 acquisitions with an aggregate purchase price of approximately $6.0 billion. We have also implemented internal expansion capital projects totaling approximately $1.8 billion. In addition, we believe we have resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2008, we had approximately $1.0 billion available under our committed credit facilities, subject to continued covenant compliance.

- *We have an experienced management team whose interests are aligned with those of our unitholders.* Our executive management team has an average of approximately 25 years industry experience, and an average of approximately 15 years with us or our predecessors and affiliates. In addition, through their ownership of 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.

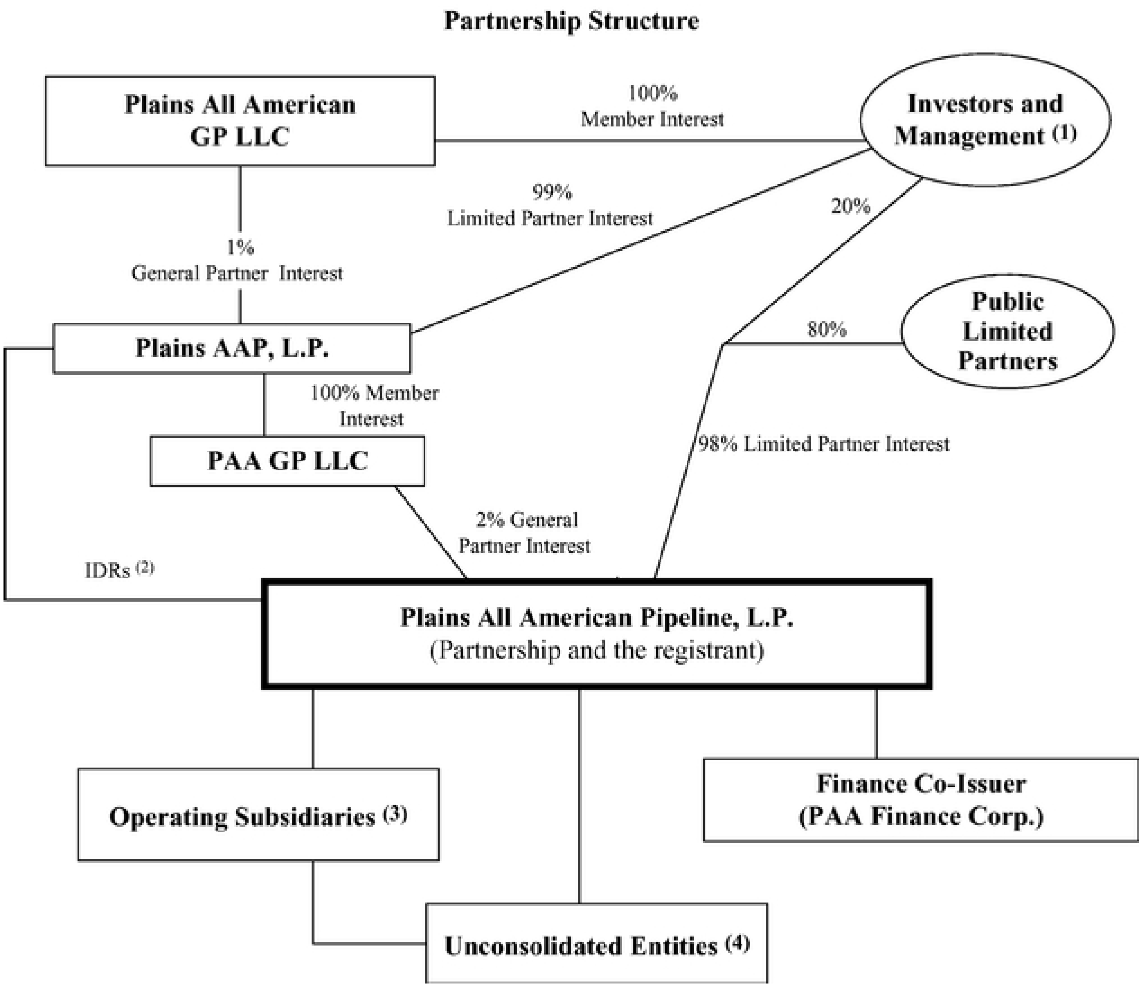
Organizational History

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 owned by 17 holders, with six of these holders each owning a minimum interest of approximately 3% and an aggregate interest of 93%. 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 (other than expenses related to the Class B units of Plains AAP, L.P.).

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



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(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 25 million limited partner units, representing approximately 20% 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 Group LLC, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P and Plains Midstream Canada ULC.

(4) The Partnership holds direct and indirect equity interests in unconsolidated entities including PAA/Vulcan, Settoon Towing, LLC ("Settoon Towing"), Butte Pipe Line Company ("Butte") and Frontier Pipeline Company ("Frontier").

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, 2008, we have completed approximately 52 acquisitions for a cumulative purchase price of approximately $6.0 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
Rainbow Pipe Line Company	May-2008	Crude oil gathering and transportation assets in Alberta, Canada	$ 687
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	59.89% interest in the Clovelly-to-Meraux ("CAM") Pipeline system; 100% interest in the Bay Marchand-to-Ostrica-to-Alliance ("BOA") system and various interests in the High Island Pipeline System ("HIPS")(1)	$ 130
Andrews Petroleum and Lone Star Trucking ("Andrews")	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.

2008 Acquisitions

During 2008, we completed two acquisitions for aggregate consideration of approximately $735 million. These acquisitions included (i) a crude oil pipeline located in Alberta, Canada (reflected in our transportation segment) for approximately $687 million in cash of which the associated goodwill was approximately $194 million and (ii) a storage facility and other assets (reflected in our facilities segment) for approximately $44 million in cash of which there was no associated goodwill.

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

The United States comprises less than 5% of the world's population and generates only 10% of the world's petroleum production, but consumes 23% 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 Energy

Information Administration's ("EIA") Annual Energy Outlook 2009 Early Release (see EIA website at *www.eia.doe.gov*).

	2008[1]	Projected 2009	2010	2015
	(In millions of barrels per day)			
Supply				
U.S.	8.5	9.1	9.7	10.2
Other OECD	12.4	12.0	12.0	11.5
Total OECD[2]	20.9	21.1	21.7	21.7
Organization of the Petroleum Exporting Countries	35.8	35.1	34.5	35.9
Other Non-OECD	28.8	30.1	30.6	31.9
Total World Production	85.5	86.3	86.8	89.5

	2008[1]	Projected 2009	2010	2015
	(In millions of barrels per day)			
Demand				
U.S.	19.7	19.2	19.8	20.2
Other OECD	28.0	28.0	27.5	27.0
Total OECD	47.7	47.2	47.3	47.2
Non-OECD	38.2	39.1	39.5	42.3
Total World Consumption	85.9	86.3	86.8	89.5
Net World Consumption	(0.4)	—	—	—
U.S. Production as % of World Production	10%	11%	11%	11%
U.S. Consumption as % of World Consumption	23%	22%	23%	23%
Net U.S. Consumption	(11.2)	(10.1)	(10.1)	(10.0)

(1) The 2008 amounts are based on ten months of actual data and two months of data derived from a short-term energy model published by the EIA.

(2) Organization for Economic Co-operation and Development

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 higher volatility in prices and market structure. In addition, the challenging global economic climate has recently resulted in lower prices as well as reduced demand.

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. and world-wide 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 fungibility 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 2008, the United States consumed approximately 14.8 million barrels of crude oil per day, while only producing 5.0 million barrels per day. Accordingly, the United States relies on foreign imports for approximately 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 23 years, increasing from 3.2 million barrels per day in 1985 to 9.8 million barrels per day for the 12 months ended October 2008, as U.S. refinery demand has increased from 12.0 million barrels per day in 1985 to 14.8 million barrels per day for the twelve months ended October 2008 and domestic crude oil production has declined due to natural depletion. The table below shows the overall domestic petroleum consumption projected out to 2015 and is derived from recent information published by the EIA (see EIA website at *www.eia.doe.gov*). The amounts in the 2008 column are based on the twelve months from November 2007 to October 2008.

		Projected		
	2008	**2009**	**2010**	**2015**
	(In millions of barrels per day)			
Supply				
Domestic Crude Oil Production	5.0	5.4	5.6	5.7
Net Imports—Crude Oil	9.8	9.0	8.3	8.2
Crude Oil Input to Domestic Refineries	14.8	14.4	13.9	13.9
Net Product Imports	1.3	1.3	1.6	1.7
Other—(NGL Production, Refinery Processing Gain)	3.6	3.5	4.3	4.6
Total Domestic Petroleum Consumption	19.7	19.2	19.8	20.2

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 2008 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)	2.7	7.0	(4.3)
PADD IV (Rockies)	0.4	0.5	(0.1)
PADD V (West Coast)	1.4	2.6	(1.2)
Total U.S.	5.0	14.8	(9.8)

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 23 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 515,000 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 2008. As a result, the volume of crude oil transported into PADD II has increased approximately 59% in absolute terms or 2.0% annually from 1.7 million barrels per day to 2.7 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 multi-year trend narrowing the gap between supply and demand;
- Temporal increases in the gap related to supply response following price spikes and declines in the rate of demand growth due to worldwide economic slowdown;
- A reduction in available tankage and U.S. inventory capacity caused by U.S. Department of Transportation ("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 are 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. Products that are used as feedstocks are typically transported by pipeline or barges to chemical plants.

Demand for refined products has generally been 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 from approximately 15.7 million barrels per day in 1985 to approximately 19.7 million barrels per day for the twelve months ended October 2008, an annual average increase of approximately 1.0%. Due to current challenging economic conditions, the EIA estimates that U.S. consumption of refined products will decline in 2009 before increasing again. We believe that the additional demand in the intermediate and long-term 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 through our:

- strategically located assets;
- specialized refined products knowledge;
- extensive relationships with refiners, other suppliers, distributors and end-users;
- strong capital structure and liquidity position; and
- proven skill sets to evaluate, acquire and integrate businesses and achieve synergies.

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 propane, butane, isobutane and other related products. These gases liquefy at moderate pressures thus allowing transportation and storage opportunities. LPG is produced domestically or imported into the U.S. from Canada and other parts of the world. Individual LPG products have specific uses. For example, propane can be used in domestic applications (home heating and cooking), industrial applications, agricultural applications (crop drying) and as an automotive fuel. Normal butane is used as a petrochemical feedstock, as a blendstock 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.

The LPG market is driven by:

- seasonal shifts in weather;
- seasonal changes in gasoline specifications affecting demand for butane;
- alternating needs of refineries to store and blend LPG;
- complex transportation logistics;
- shortages of diluent for Canadian heavy oil; and
- inefficiencies caused by 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.

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 2007, domestic natural gas production grew approximately 0.4% annually while domestic natural gas consumption rose approximately 1.0% annually, resulting in an approximate 3.1% annual 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. However, this trend of an increasing domestic supply shortfall is not expected to continue. During 2008, domestic production increased approximately 6% over production levels in 2007, with the majority of the increases being associated with onshore development of various resource plays, including shale gas. Through 2008, consumption of natural gas was approximately the same as consumption in 2007 on an average daily basis.

The downturn in the economy clearly has had a negative impact on industrial demand. A portion of this demand destruction has been offset by a significant decrease in commodity price coupled with continued growth for natural-gas fired electric generation. An unprecedented amount of new infrastructure in the form of large diameter pipelines bringing unconventional supply (shale gas) to markets to meet this forecasted demand will have a significant impact on changing traditional physical flows of natural gas particularly in the Gulf Coast area. Even with the growth of unconventional shale plays, North American LNG imports are forecasted to play a potentially significant role. LNG imports totaled approximately 2.1 Bcf per day in 2007 and 1.0 Bcf per day in 2008, but are projected to increase to 4.2 Bcf per day in 2014 with the majority of this supply expected to be delivered to the U.S. markets in the spring and summer.

We believe new pipeline infrastructure, increased domestic supply and increased seasonal deliveries of LNG combined with fluctuations in domestic consumption related to seasonal and economic factors will continue to drive demand for strategically located natural gas storage facilities with multi-cycle injection and withdrawal capabilities. We believe our natural gas storage locations, which have access to critical transportation infrastructure, will continue to 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, strategically located assets, financial strength and 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 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. 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, Frontier and Settoon Towing, in which we own non-controlling interests.

As of December 31, 2008, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 17,000 miles of active crude oil and refined products pipelines and gathering systems;
- 24 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 1 million barrels of crude oil linefill in pipelines owned by us;
- 86 trucks and 341 trailers; and
- 65 transport and storage barges and 36 transport tugs through our interest in Settoon Towing.

Following is a tabular presentation of our active pipeline assets in the United States and Canada as of December 31, 2008, grouped by geographic location:

Region / Pipeline and Gathering Systems[1]	System Miles	2008 Average Net Barrels per Day (in thousands)[2]
Southwest US		
Basin	521	377
Other	4,135	467
Southwest US Subtotal	**4,656**	**844**
Western US		
All American	138	45
Line 63/Line 2000	459	147
Other	155	103
Western US Subtotal	**752**	**295**
US Rocky Mountain		
Salt Lake City Area Systems	1,011	93
Other	3,289	266
US Rocky Mountain Subtotal	**4,300**	**359**
US Gulf Coast		
Capline[3]	633	219
Other	1,035	311
US Gulf Coast Subtotal	**1,668**	**530**
Central US Subtotal	**2,921**	**392**
Domestic Total	**14,297**	**2,420**
Canada		
Rangeland	900	58
Rainbow[4]	599	193
Manito	605	70
Other	635	175
Canada Total	**2,739**	**496**
Grand Total	**17,036**	**2,916**

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

(2) Represents average volumes for the entire year, except for Rainbow, which was acquired during May 2008.

(3) Non-operated pipeline.

(4) Rainbow 2008 average net barrels per day was calculated based on a 245-day period, which was the number of days we owned the asset in 2008.

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 521-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 377,000 barrels per day (attributable to our interest) during 2008.

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 7 million barrels (6 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 128 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 (or contracted) tariffs. For 2008, 2007 and 2006, tariffs on the All American Pipeline averaged $2.24 per barrel, $2.18 per barrel and $2.07 per barrel, respectively. The agreements do not require these owners to transport a minimum volume. These agreements 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,				
	2008	2007	2006	2005	2004
Average daily volumes received from:					
Point Arguello (at Gaviota)	7	8	9	10	10
Santa Ynez (at Las Flores)	38	38	40	41	44
Total	45	46	49	51	54

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 115-mile trunk pipeline (of which 101 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 26 miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and 188 miles of gathering pipelines in the San Joaquin Valley, with a throughput capacity of approximately 72,000 barrels per day. We also have 25 storage tanks with approximately 1 million barrels of storage capacity on this system. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system. For 2008, combined throughput on Line 63 totaled an average of approximately 89,000 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 130-mile, 20-inch trunk pipeline with a throughput capacity of 130,000 barrels per day. During 2008, throughput on Line 2000 averaged approximately 58,000 barrels per day.

US Rocky Mountain

Salt Lake City Area Systems. We own and operate 100% of 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 to refiners in Salt Lake City, Utah. The Salt Lake City Core Area systems consist of 1,011 miles of pipelines (including the Wahsatch Expansion discussed below) and 26 storage tanks with a total storage capacity of approximately 1 million barrels. The trunk pipeline originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming and various other points between Guernsey and Salt Lake City, and can deliver to Salt Lake City, Utah and Rangely, Colorado. The Salt Lake City Core Area systems have a combined throughput capacity of approximately 120,000 barrels per day to Salt Lake City. During 2008, throughput on the Salt Lake City Core Area systems averaged approximately 93,000 barrels per day.

In the fourth quarter of 2008, we completed construction on a 93-mile expansion of the Salt Lake City Core Area system from Wahsatch, Utah to Salt Lake City, which has throughput 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-Operating, L.P. As part of this agreement, Holly Refining and Marketing Company has entered into a 10-year transportation agreement on terms consistent with the four previously committed refiners. Plains' portion of the total project cost was approximately $215 million. We expect to place the line in service and close on this agreement in the first quarter of 2009.

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. Total system operating capacity is approximately 1 million barrels per day of crude oil, of which approximately 248,000 barrels per day is attributable to our interest. During 2008, throughput on our interest averaged approximately 219,000 barrels per day.

Canada

Rainbow System. We own a 100% interest in the Rainbow system. The Rainbow system is 599 miles long consisting of a 480-mile, 20-inch mainline crude oil pipeline extending from the Norman Wells Pipeline located in Zama, Alberta to Edmonton, Alberta and 119 miles of gathering pipelines. The system has a throughput capacity of approximately 200,000 barrels per day and has transported approximately 193,000 barrels per day since we acquired it in May 2008.

Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system includes the Mid Alberta Pipeline ("MAPL") and the Rangeland Pipeline. MAPL is a 139-mile proprietary pipeline with a throughput capacity of approximately 50,000 barrels per day if transporting light crude oil. Currently, MAPL originates in Edmonton, Alberta and terminates in Sundre, Alberta, where it connects to the Rangeland Pipeline. We plan to reverse MAPL allowing for flow from Rangeland's Sundre terminal directly to Edmonton. The Rangeland Pipeline is a proprietary pipeline system that consists of approximately 761 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 on our system once MAPL is reversed) 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 264 miles of trunk pipelines and has a current throughput capacity of approximately 83,000 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 50-mile pipeline for condensate and butane. From Rimbey, third-party pipelines move product north to Edmonton. For 2008, approximately 34,000 barrels per day of crude oil was transported on the segment of the pipeline from Sundre north to Edmonton and approximately 24,000 barrels per day was transported on the pipeline from Sundre south to the United States. There is approximately 80,000 barrels of tankage at the pipeline terminals at Edmonton. An additional 240,000 barrels of tankage is under construction at Edmonton and is expected to be completed in 2009.

Manito. We own a 100% interest in the Manito heavy oil system. This 605-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 376 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 2008, approximately 70,000 barrels per day of crude oil was transported in the Manito system.

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. 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. At December 31, 2008, PAA/Vulcan owned and operated approximately 31 billion cubic feet of underground natural gas storage capacity, which includes 5 billion cubic feet that was placed in service during October 2008, and another 2 Bcf of storage capacity leased from third parties. We are developing an additional 19 billion cubic feet of underground storage capacity, which is expected to be placed into service in phases over the next several years.

As of December 31, 2008, we owned and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 55 million barrels of crude oil and refined products capacity primarily at our terminalling and storage locations;
- approximately 6 million barrels of LPG storage 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 22,500 barrels per day.

At year-end 2008, we were in the process of constructing approximately 5 million barrels of additional above-ground crude oil and refined product terminalling and storage facilities.

Following is a tabular presentation of our active facilities segment assets in the United States and Canada as of December 31, 2008, grouped by product type:

Facility	Capacity (in millions of barrels, except where noted)
Crude Oil and Refined Products	
Cushing	11
Kerrobert	1
L.A. Basin	10
Martinez and Richmond	5
Mobile and Ten Mile	2
Patoka	3
Philadelphia Area	3
St. James	6
Other	14
Subtotal	**55**
LPG	
Bumstead	2
Tirzah	1
Other	3
Subtotal	**6**
Natural Gas	
Bluewater/Kimball(1)	26 Bcf(2)(3)
Pine Prairie(1)	5 Bcf(2)(3)

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

(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 is 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 operational safeguards that distinguish it from 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. See "New Crude Oil Storage Facilities Under Construction and Under Development" below for discussion of ongoing expansion activities at this facility.

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 1 million barrels. The cost of these expansions totaled approximately $42 million. In 2008, we commenced 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 $43 million, of which approximately $34 million is estimated to be incurred in 2009.

L.A. 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 37 storage tanks. Approximately 9 million barrels of the storage capacity are in commercial service (including approximately 1 million barrels that were placed in service in 2008 at a cost of $21 million) and 1 million barrels are used primarily for throughput to other storage tanks and for displacement oil and do not generate revenue independently. 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.

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, of which approximately half of the storage capacity is included within the transportation segment.

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.

Patoka Terminal. We recently constructed three 670,000-barrel and two 400,000-barrel tanks at the Patoka Interchange located in southern Illinois. The terminal was substantially completed during the fourth quarter of 2008 at a cost of $85 million; however, additional third-party pipeline connections remain to be completed in the first quarter of 2009, which we estimate will cost $2 million. We anticipate 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. See "New Crude Oil Storage Facilities Under Construction and Under Development" below for discussion of ongoing expansion activities at this facility.

Philadelphia Area Terminals. We own three refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have 42 storage tanks ranging in size from 11,000 barrels to 150,000 barrels with a 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.

We are in the process of expanding the facilities by approximately 1 million barrels consisting of eight tanks ranging from 50,000 barrels to 150,000 barrels, of which three 150,000-barrel tanks were placed into service during 2008. The remaining five tanks are scheduled to be completed in the second quarter of 2009 at an estimated remaining cost of $13 million.

St. James Terminal. In 2008, we substantially completed 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. Phases I and II in aggregate consist of approximately 6 million barrels of capacity and include eleven tanks ranging from 210,000 barrels to 700,000 barrels. One tank remains to be completed early in 2009. The facility also includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. See "New Crude Oil Storage Facilities Under Construction and Under Development" below for discussion of ongoing expansion activities at this facility.

New Crude Oil Storage Facilities Under Construction and Under Development

Cushing Terminal. During 2009, we will begin construction on additional crude oil tankage at our Cushing terminal. The project will include the construction of three 570,000-barrel tanks with the option to add a fourth tank during construction. This expansion is supported by long-term customer commitments. The estimated cost of construction is approximately $46 million.

Patoka & St. James Terminals and Dock. During 2009, we will begin construction on light-product storage tankage at the Patoka and St. James terminal locations. The project will include the construction of two 300,000-barrel tanks at the Patoka terminal and three 300,000-barrel tanks at the St. James terminal. This new tankage at both facilities will complement the new dock that is currently under construction at the St. James location. The cost of the project in aggregate, including the dock, is estimated to be approximately $167 million.

Pier 400. For a number of years, we or our predecessors have been involved in an effort to develop 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.

In 2004, 2005 and 2007, we entered into or modified 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 and other economic conditions set forth in our agreements with our customers, and we are likely to miss other project objectives that are key conditions in each of our agreements.

The project involves a number of state, local and federal agencies and regulatory bodies and, accordingly, the regulatory processes are complex and interrelated with our customer negotiations. These regulatory bodies include 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. In addition, 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 and receipt of environmental and other approvals.

The estimated cost of the project has increased significantly during the regulatory approval process due to increased service and supply costs of the original project, changes in scope of the project to meet long-term objectives of the various regulatory bodies and incremental costs associated with adapting to environmental safeguards and protections required by the governing bodies. We are in the process of completing an updated cost estimate for the Pier 400 project, but based on conditions existing in early 2009 we estimate that the project will cost approximately $575 to $600 million to complete, including $47 million of costs associated with emission reduction credits and development and engineering costs incurred to date and $41 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.

Although we continue to work together with customers and regulatory bodies in an attempt to advance the project, due to the aforementioned factors as well as the impact of a weakening economic environment, we can provide no assurance that (i) the project will receive all the necessary regulatory approvals (although we know of no reason that it should not receive regulatory approvals); (ii) even if approved, the project will be constructed; or (iii) if constructed, the project will generate satisfactory economic returns.

LPG Storage Facilities

Bumstead. 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.

Tirzah. The Tirzah facility is located in South Carolina and has an underground granite storage cavern with approximately 1 million barrels of capacity and is connected to the Dixie Pipeline System (a third-party system) via our 62-mile pipeline. The facility gives us a greater presence in the Southeast and we believe this facility will further support the expansion of our LPG business in North America.

LPG Processing

Shafter. Our Shafter facility located near Bakersfield, California provides isomerization and fractionation services to producers and customers of natural gas liquids ("NGL"). The primary assets consist of 200,000 barrels of NGL storage and a processing facility with butane isomerization capacity of 14,000 barrels per day and NGL fractionation capacity of 8,500 barrels per day.

Natural Gas Storage Assets (owned through our 50% interest in PAA/Vulcan and operated by PAA)

Bluewater/Kimball. The Bluewater gas storage facility, which is strategically located near Detroit, Michigan, is a depleted reservoir with approximately 23 Bcf of capacity. In April 2006, PAA/Vulcan acquired the Kimball gas storage facility and connected this approximately 3 Bcf facility to the Bluewater pipeline system. 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 a 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 three major pipelines and three major natural gas utilities as well as indirect access to Dawn, a major natural gas market hub in Canada. In addition to owning these facilities, from time-to-time, PAA/Vulcan leases capacity at other facilities to augment the services it provides.

Pine Prairie. Pine Prairie Energy Center ("Pine Prairie") is a high deliverability salt dome storage facility located just northwest of Lafayette, Louisiana, approximately 50 miles from the Henry Hub in Louisiana (the delivery point for NYMEX natural gas futures contracts) near Gulf Coast supply sources and LNG import terminals. The initial phase of the facility consists of three storage caverns with a permitted working capacity of 24 Bcf and an extensive header system. Drilling operations on all three cavern wells are complete. Pine Prairie began commercial operations in October 2008 with approximately 5 Bcf of working gas storage in cavern one. Cavern two with approximately 8 Bcf of capacity is expected to be placed in service in the second quarter of 2009 followed by cavern three in the second quarter of 2010. Pine Prairie is currently connected to seven major pipelines serving the Midwest, Southeast, Mid-Atlantic and Northeast markets. 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 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 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. 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). See "—Crude Oil Volatility; Counter-Cyclical Balance; Risk Management" for further discussion.

Except for pre-defined inventory positions, our policy is generally (i) to purchase only product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive, and (iii) 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 associated with its merchant activities, as of December 31, 2008, our marketing segment also owned significant volumes of crude oil and LPG classified as long-term assets for linefill or minimum inventory requirements under service arrangements with transportation carriers and terminalling providers. The marketing segment also employs 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 us;
- 2 million barrels of crude oil and LPG linefill in pipelines owned by third parties and other long-term inventory;
- 528 trucks and 631 trailers; and
- 1,697 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. Intersegment sales are based on posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. However, certain terminalling and storage rates recognized within our facilities segment 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 overall 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 marketing activities for the year ended December 31, 2008 (in thousands of barrels per day):

	Volumes
Crude oil lease gathering purchases	658
Refined products sales	26
LPG sales	103
Waterborne foreign crude oil imported	80
Marketing activities total	867

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 our trucking fleet as well as 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 the 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 15 days of the date of invoice and refined products sales settle within 10 days.

Certain activities in our marketing segment are affected by seasonal aspects, primarily with respect to LPG marketing activities, which generally have higher activity levels during the first and fourth quarters of each year.

Crude Oil Volatility; Counter-Cyclical Balance; Risk Management

Crude oil commodity prices have historically been very volatile and cyclical, and continue to reflect such a trend. For example, over the last 22 years, NYMEX WTI crude oil benchmark prices have ranged from a low of approximately $10 per barrel during March 1986 to a high of over $147 per barrel during July 2008. During more recent months, crude oil prices plummeted from the aforementioned high of $147 per barrel to a five year low of less than $33 per barrel in December 2008. 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 segment profit 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.

Counter-Cyclical Balance

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. 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.

Risk Management

As use of the financial markets for crude oil by producers, refiners, utilities and trading entities has increased, risk management strategies 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. These derivative instruments include exchange traded futures, options and swaps, 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 and manage 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 marketing 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. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time. 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 and a substantially lesser amount for LPG. 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 accounted for 14%, 19% and 14% of our revenues for each of the three years ended December 31, 2008, 2007 and 2006, respectively. Valero Marketing & Supply Company accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 12% and 11% of our revenues for the years ended December 31, 2008 and 2007, respectively. 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. For a discussion of customers and industry concentration risk, see Note 8 to our Consolidated Financial Statements.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and demand for the crude oil by end users. We believe that high capital requirements, environmental considerations and the difficulty in acquiring rights-of-way and related permits make it unlikely that competing pipeline systems comparable in size and scope to our pipeline systems will be built in the foreseeable future. However, to the extent there are already third-party owned pipelines 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 assets, operations and business activities are subject to extensive legal requirements and regulations under the jurisdiction of numerous federal, state, provincial and local agencies. Many of these agencies are authorized by statute to issue and have issued requirements binding on the pipeline industry, related businesses and individual participants. The failure to comply with such legal requirements and regulations can result in substantial penalties. At any given time there may be proposals, provisional rulings or proceedings in legislation or under governmental agency or court review that could affect our business. The regulatory burden on our assets, operations and activities increases our cost of doing business and, consequently, affects our profitability, but we do not believe that these laws and regulations affect us in a significantly different manner than our competitors. We may at any time also be required to apply significant resources in responding to governmental requests for information. The U.S. Commodity Futures Trading Commission (the "CFTC") launched a national crude oil pricing investigation in late 2007. We responded throughout 2008 to a series of requests/demands for information from the CFTC in connection with such investigation. We worked with the CFTC to focus the scope of the inquiry and limit the amount of information we were required to deliver. Within that limited scope, we believe we have completed our response. We may not know when the CFTC has completed its investigation, and the CFTC may at any time broaden the scope of inquiry and require additional information. Early in 2008, the DOT's Pipeline Hazardous Materials Safety Administration ("PHMSA") informed us that Plains had been selected among several other pipeline operators for a pilot test of a comprehensive "integrated" inspection and audit of pipeline safety compliance. We dedicated significant human resources in cooperating with PHMSA in the audit, which included a two-week long review session in our Houston office followed by field tours and records reviews in four separate operational locations. PHMSA has not yet shared its final audit conclusions. 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, but not all, of the laws and regulations affecting our operations.

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 doing 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 the issuance of injunctions that may subject us to additional operational constraints that our competitors are not required to follow. Environmental and safety laws and regulations are subject to change that may result 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 third parties. The following is a summary of some of the environmental and safety laws and regulations to which our operations are subject.

Pipeline Safety/Pipeline and Storage Tank Integrity Management

A substantial portion of our petroleum pipelines and our storage tank facilities in the United States are subject to regulation by the PHMSA pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended (the "HLPSA"). The HLPSA imposes safety requirements on the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Federal regulations implementing the HLPSA require pipeline operators to adopt measures designed to reduce the environmental impact of oil discharges from onshore oil pipelines, including the maintenance of comprehensive spill response plans and the performance of extensive spill response training for pipeline personnel. These regulations also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations. Regulation in Canada is under the National Energy Board ("NEB") and provincial agencies.

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. These amendments have resulted in the adoption of rules by the DOT that require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures to ensure pipeline safety in "high consequence areas," such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. Costs associated with the inspection, testing and correction of identified anomalies were approximately $23 million in 2008, $15 million in 2007 and $8 million in 2006. Based on currently available information, our preliminary estimate for 2009 is that we will incur approximately $10 million in operational expenditures and approximately $22 million in capital expenditures associated with our pipeline integrity management program. The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, we will continue to focus on pipeline integrity management as a primary operational emphasis. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented. Currently, we believe our pipelines are in substantial compliance with HLPSA and the more recent 2002 and 2006 amendments.

On June 3, 2008, PHMSA published a final rule amending its pipeline safety regulations to extend protection to designated unusually sensitive areas or "USAs" that could be damaged by failure of certain rural onshore hazardous liquid gathering lines or low-stress pipelines. These USAs include locations containing sole-source drinking water, endangered species, or other ecological resources. Operators of rural onshore hazardous liquid gathering lines must comply with safety requirements to address threats of corrosion and third-party damage to their lines by developing a damage prevention program, complying with specified corrosion control requirements, and monitoring and mitigating conditions that could lead to internal corrosion. Moreover, the final rule narrows the regulatory exception for rural onshore low-stress hazardous liquid pipelines by extending existing safety regulations (including integrity management requirements) to certain low-stress pipelines within a defined "buffer" area around a USA. The effective date of this final rule was July 3, 2008, with operational requirements being phased in over time, generally beginning in 2009. We have less than 300 miles of pipeline subject to the new rule and do not expect compliance to have a material effect on our operating expenses.

We have expanded an internal review process in which we are reviewing the condition and operating history of certain 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.

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 issued guidelines with respect to securing regulated facilities against terrorist attack. We have instituted security measures and procedures in accordance with such guidelines to enhance the protection of certain of our facilities. We cannot provide any assurance that these security measures would fully protect our facilities from a concentrated attack.

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, subject to an applicable waiver or stay, is required in May 2009. Costs associated with this program were approximately $41 million, $18 million and $7 million in 2008, 2007 and 2006, respectively. Based on currently available information, we anticipate we will spend approximately $32 million in 2009 in connection with API 653 compliance activities. Certain storage tanks may be taken out of service if we believe the cost of upgrades will exceed the value of the storage tanks or replacement tankage may be constructed at a more optimal location. In addition, due primarily to decreased crude oil consumption, market conditions during the first part of 2009 have resulted in a significant demand for storage capacity. Accordingly, we may elect to spend more in 2009 than initially forecasted if economic conditions warrant.

In Canada, the NEB and provincial agencies such as the Energy Resources Conservation Board ("ERCB") in Alberta and the 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 $8 million in 2008, $6 million in 2007 and $5 million in 2006. Our preliminary estimate for 2009 is approximately $20 million. Certain of these costs are recurring in nature and thus will affect future periods.

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.

Occupational Safety and Health

We are subject to the requirements of the Occupational Safety and Health Act, as amended ("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.

Solid Waste

We generate wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended, ("RCRA") and analogous 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. It is possible, however, 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 will be subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses.

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. 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." We have knowledge of two Superfund sites where an affiliate (Scurlock Permian LLC) of a predecessor owner (Marathon Ashland Petroleum or "MAP") of assets we now own was alleged to have deposited waste oils, but MAP has contractually indemnified us for any liabilities associated with these two sites. Canadian and provincial laws also impose liabilities for releases of certain substances into the environment.

Environmental Remediation

We currently own or lease, and in the past have owned or leased, 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) and to clean up contaminated property (including contaminated groundwater).

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 conjunction with our acquisitions, we make an assessment of potential environmental exposure and determine whether to negotiate an indemnity, what the terms of any indemnity should be and whether to obtain environmental risk insurance, if available. 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 former Texas New Mexico ("TNM") pipeline 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, of which we agreed in an arrangement with TNM to bear the first $11 million in costs of pre-May 1999 environmental issues. TNM also agreed to pay all costs in excess of $20 million (excluding certain deductibles). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). As of December 31, 2008, we had incurred approximately $9 million of remediation costs associated with these sites, while SOP's share is approximately $5 million. In another example, as a result of our merger with Pacific, we assumed liability for a number of ongoing remediation sites associated with releases from pipeline or storage operations. We have evaluated each of the sites requiring remediation and developed reserve estimates for the Pacific sites, which total approximately $21 million. See Item 3. "Legal Proceedings."

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.

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

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 to install air pollution control equipment and otherwise comply with more stringent state and regional air emissions control when we attempt to obtain or maintain permits and approvals for sources of air emissions. Although we believe that our operations are in substantial compliance with these laws in the 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.

Climate Change Initiatives

In response to recent studies suggesting that emissions of carbon dioxide, methane and certain other gases may be contributing to warming of the Earth's atmosphere, many nations, including Canada, have agreed to limit emissions of these gases, generally referred to as greenhouse gases ("GHG"), 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 GHG to 6% below 1990 levels by 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 GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations are expected to become effective in 2010.

Although the United States is not participating in the Kyoto Protocol, the U.S. Congress has been actively considering legislation to reduce emissions of GHGs. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of GHGs, primarily through the development of GHG emission inventories and/or regional GHG cap and trade programs. Also, on April 2, 2007, the U.S. Supreme Court in *Massachusetts, et al. v. EPA* held that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act and that EPA must consider whether it is required to regulate GHG emissions from mobile sources such as cars and trucks. Moreover, the Court's holding in *Massachusetts* that GHGs fall under the federal Clean Air Act's definition of "air pollutant" also may result in future regulation of GHG emissions from stationary sources such as refineries and power plants. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of GHG emissions under the Clean Air Act, in response to the Supreme Court's decision in *Massachusetts*. In the notice, EPA evaluated the potential regulation of GHGs under the Clean Air Act and other potential methods of regulating GHGs. Although the notice did not propose any specific, new regulatory requirements for GHGs, it indicates that federal regulation of GHG emissions could occur in the near future. Thus, there may be restrictions imposed on the emission of GHGs if Congress does not adopt new legislation specifically addressing emissions of GHGs.

Operational components of our stationary facilities that require the combustion of carbon-based fuel (such as compression stations, line heaters and internal combustion engine-driven pumps) produce GHG emissions in the form of CO2. Although we believe that these emissions in the aggregate are not significant relative to other industries that are fuel-combustion intensive, we have commenced a process of identifying potential emission sources and establishing GHG inventories for such sources.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows.

Water

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act ("CWA") and analogous state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. See "—Pipeline Safety/Pipeline and Storage Tank Integrity Management" and Note 11 to our Consolidated Financial Statements. 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 CWA.

The Oil Pollution Act of 1990 ("OPA") amended certain provisions of the CWA, as they relate to the release of petroleum products into navigable waters. 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. 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.

Other Regulation

Transportation Regulation

Our transportation activities are subject to regulation by multiple governmental agencies. 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 types of transportation regulation 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 ("ICA"). The ICA 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 13 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 requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. In June 2008, the Minerals Management Service issued a final rule establishing formal and informal complaint procedures for shippers that believe they have been denied open and nondiscriminatory access to transportation on the OCS. We do not expect the rule 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 to establish 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 establishing a methodology for petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index (currently, the producer price index for finished goods plus 1.3 percent). Pipelines are allowed to raise their rates to the rate ceiling level generated by application of the index. If the methodology reduces the ceiling level such that it is lower than a pipeline's filed rate, the pipeline must reduce its rate to conform 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, use the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates, agreement with an unaffiliated shipper, and settlement as alternatives to the indexing approach that may be used in certain specified circumstances. The FERC's indexing methodology is subject to review every five years; the current methodology will remain in place through June 30, 2011. Because the indexing methodology is tied to an inflation index and is not based on pipeline-specific costs, the indexing methodology could hamper our ability to recover cost increases.

Under the EPAct, petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct are deemed to be just and reasonable under the ICA, if such rates had not been subject to complaint, protest or investigation during that 365-day period. 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. Litigation is ongoing at FERC regarding the methodology to be applied for determining whether there has been "substantial change" under EPAct. We have no way of knowing what result FERC will reach in these proceedings.

FERC permits entities owning public utility assets, including oil pipelines, to include an income tax allowance in their 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. A tax pass-through entity such as a master limited partnership ("MLP") 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. FERC continues to refine its tax allowance policy in case-by-case reviews; how the tax allowance policy is applied in practice to pipelines owned by MLPs could affect the rates of pipelines regulated by FERC.

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, log book maintenance, truck manifest preparations, safety placard placement on the trucks and trailer vehicles, drug and alcohol testing, operation and equipment safety, and many other aspects of truck operations. We are also subject to 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 licensing, 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 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.

Standards of Conduct for Transmission Providers. Historically, FERC's standards of conduct regulations (now vacated) generally 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. The standards of conduct did not apply, however, to natural gas storage providers authorized to charge market-based rates that (i) were not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline, and (ii) had no exclusive franchise area, no captive ratepayers, and no market power. In January of 2006, the FERC found that PAA/Vulcan's Pine Prairie Energy Center 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 the FERC. Following a notice of proposed rulemaking, on October 16, 2008, the FERC issued its revised Standards of Conduct for Transmission Providers ("Standards of Conduct"). The Standards of Conduct continue to exempt natural gas storage providers like PAA/Vulcan's Pine Prairie Energy Center and its Bluewater facility. However, requests for rehearing of the October 16, 2008 order are pending with the FERC. Accordingly, there may be further modifications to the Standards of Conduct upon rehearing.

On November 20, 2008, the FERC issued a final rule that requires interstate pipelines and certain non-interstate facilities to post certain daily capacity and volume information. The rule extends to storage facilities (such as Bluewater) that provide no-notice service. The rule has been appealed, but pending the results of that appeal, Bluewater will have a requirement to post volumes with respect to no-notice service flows at each receipt and delivery point.

Energy Policy Act of 2005. On January 19, 2006, the FERC issued Order No. 670, which implements the anti-manipulation provision of EPAct 2005. Pursuant to EPAct 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 the 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. EPAct 2005 also gives the 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 anti-manipulation rule and enhanced civil penalty authority reflect an expansion of the FERC's Natural Gas Act enforcement authority.

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 the time 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. 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 3,302 employees at December 31, 2008. None of the employees of our general partner were subject to a collective bargaining agreement, except for eight employees covered by one agreement and another eight employees covered by another agreement. Both collective bargaining agreements are scheduled for renegotiation in September 2009. Our general partner considers its employee relations to be good.

Summary of Tax Considerations

The following is a brief summary of material tax considerations of owning and disposing of common units, however, the tax consequences of ownership of common units depends in part on the owner's individual tax circumstances. It is the responsibility of each unitholder, either individually or through a tax advisor, to investigate the legal and tax consequences, under the laws of pertinent U.S. federal, 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.

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 generated by us 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 or suspended 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.

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

Certain Risks are Amplified by the Current Economic Environment

During 2007, the U.S. and many key countries began to exhibit signs of economic weakness, which continued throughout 2008 and into 2009. This weakness had a severe adverse impact on the global financial system, stressing a number of large financial institutions to the point of failure, merger or requiring government assistance and resulting in a severe reduction in available capital. Capital constraints coupled with significant energy price volatility have produced pervasive liquidity issues for many companies. Such events have created pronounced uncertainty in the economic outlook, and have amplified the potential impact and likelihood of occurrence of certain risks inherent in our business. Such amplified risks include:

- Increased cost of capital and increased difficulties accessing capital to fund expansion and acquisition activities as well as routine operating requirements;
- The inability or unwillingness of lenders to honor their contractual commitments;
- The failure of customers to timely or fully pay amounts due to us;
- The failure of suppliers to pay third parties under obligations for which we have potential contingent liabilities;
- The potential for adverse actions by rating agencies;
- Potentially adverse changes in tax laws;
- The failure of counterparties to fulfill their delivery or purchase obligations;
- Business failures by vendors, suppliers or customers that result in (i) delays in progress on our capital projects, (ii) nonpayment of receivables or (iii) expensive and protracted court or bankruptcy proceedings;
- Increased criminal activities, including fraud, theft, vandalism and random violence that could affect our assets or business activities; and

- Decreases in domestic consumption or in volumes imported to or produced in the United States and related reductions in transportation, terminalling or marketing margins.

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, the Cushing, St. James and Patoka terminal and dock 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. 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.

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 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.

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 and a substantially lesser amount for LPG. 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 four years. As we add assets, we historically have experienced a corresponding increase in the relative number of releases of crude oil into the environment. Although we believe we have reduced the trend, additional assets acquired in the future could again result in increased frequency of releases. 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 twice the miles of pipeline we owned five 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 historically have observed an increase in the number of releases of liquid hydrocarbons into the environment. Although we believe that our integrity management efforts (discussed below) have been successful in reversing that trend, the future acquisition of assets could once again result in an increase in the overall number of releases. 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. These new regulations, adopted in July 2008, include requirements for the establishment of additional pipeline integrity management programs. See Items 1 and 2. "Business and Properties—Regulation—Environmental, Health and Safety Regulation—Pipeline Safety/Pipeline and Storage Tank Integration Management."

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."

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, earthquakes 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 OCS 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. 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.

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. 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 businesses or assets 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 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. Wide contango spreads combined with price structure volatility generally have a favorable impact on our results. 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. If the market is in a backwardated to transitional structure, our results from our marketing segment may be less than those generated during the more favorable contango market conditions. Additionally, a prolonged transition period or a lack of volatility in the pricing structure may further negatively impact our results. 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.

Our 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 ICA. The ICA 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.

For our U.S. interstate common carrier pipelines subject to FERC regulation under the ICA, shippers may protest our pipeline tariff filings, or the FERC can investigate on its own initiative. Under certain circumstances, the FERC could limit our ability to set rates based on our costs, or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint. Natural gas storage facilities are subject to regulation by the FERC and certain state agencies. A change in PAA/Vulcan's rate structure could adversely affect its revenues.

Our Canadian pipelines are subject to regulation by the NEB and 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, we compete with other storage providers, including 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 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. 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.

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, 2008, our consolidated debt outstanding was approximately $4.3 billion, consisting of approximately $3.3 billion principal amount of long-term debt (including senior notes) and approximately $1.0 billion of short-term borrowings. As of December 31, 2008, we had approximately $1.0 billion of available borrowing capacity under our senior unsecured revolving credit facility and our senior secured hedged inventory 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—Sources of Liquidity—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.

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 third-party assets for certain of our operations.

Certain of our business activities require the use of third-party assets over which we may have little or no control. For example, a portion of our storage and distribution business conducted in the Los Angeles basin (acquired in connection with the Pacific merger) receives waterborne crude oil 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.

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, 2008, we had approximately $4.3 billion of consolidated debt, of which approximately $3.1 billion was at fixed interest rates and approximately $1.2 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. For example, the financial market turmoil, which started in 2007 and continued through 2008, impacted the exchange rate, specifically within the latter portion of 2008. The average monthly exchange rate for the Canadian dollar to U.S. dollar ranged between $1.00:1 and $1.06:1 during the first nine months of 2008, but spiked to a range between $1.18:1 and $1.23:1 during the fourth quarter of 2008.

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, 2008, we had $1.2 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.

We may enter into lines of business that are distinct and separate from our historical operations and that involve different commercial, operational and regulatory issues. For example, although many aspects of the natural gas storage and refined products industries are similar to our crude oil operations, our current management had little experience in operating natural gas storage facilities or refined products assets prior to our acquisition of such 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 unfamiliar operations could adversely affect our existing business.

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. 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 (other than expenses related to the Class B units of Plains AAP, L.P.). 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 $66^{2}/_{3}$% 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. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

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:

- 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, 2008, our total outstanding debt was approximately $4.3 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.

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

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

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

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

- that subsidiary incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or that subsidiary contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or
- that subsidiary did not receive fair consideration or reasonable equivalent value for issuing the guarantee and, at the time it issued the guarantee, that subsidiary:
  - was insolvent or rendered insolvent by reason of the issuance of the guarantee;
  - was engaged or about to engage in a business or transaction for which the remaining assets of that subsidiary constituted unreasonably small capital; or
  - intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

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

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

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

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

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

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

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

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

- to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);
- to provide funds for distributions to our unitholders and the general partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

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

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for 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 became 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. 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 positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all 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 U.S. 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, 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 U.S. 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.

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there is no tax concept of loaning a partnership interest, a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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 have recently considered 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 considered legislation would not have appeared to have affected our treatment as a partnership, we are unable to predict whether any of these changes, or other proposals will be reintroduced or 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.

Our method of proration of items of income, gain, loss and deduction between transferors and transferees 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 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 the DOJ and EPA. Our assessment is that it is probable we will pay penalties related to the releases. We may also be subjected to injunctive remedies that would impose additional requirements, costs 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 the EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. Such statutes contemplate the potential for substantial reduction in penalties based on mitigating circumstances and factors. We believe that several of such circumstances and factors exist, and thus have been a primary focus in our discussions with the DOJ and EPA with respect to these matters.

SemCrude Bankruptcy. We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude. As a result of our statutory protections and contractual rights of setoff, substantially all of our pre-petition claims against SemCrude should be satisfied. Certain creditors of SemCrude and its affiliates have challenged our contractual and statutory rights to setoff certain of our payables to the debtor against our receivables from the debtor. The aggregate amount subject to challenge is approximately $62 million. We intend to vigorously defend our contractual and statutory rights.

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 the pipeline 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 and recovered under a pre-existing PPS pollution liability insurance policy.

In connection with this release, 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 alleged 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. On October 15, 2008 this criminal action (all four counts) was dismissed with prejudice and PPS was not subjected to any fine or penalty.

In September 2008, PPS was served by the State of California with a civil complaint in connection with this release, in the Los Angeles Superior Court Case No. BC398627, alleging violations of the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, violations of two sections of the California Water Code for the unlawful discharge of waste into state waters without a permit, and violations of the Public Nuisance Code alleging that discharge of petroleum into waters of the state had created a public nuisance. This case was settled in October 2008. Pursuant to the terms of the settlement agreement, PPS paid no fine or penalty, but made civil settlement payments to various agencies of the State of California in the total amount of approximately $1.1 million.

United States of America v. Pacific Pipeline System, LLC. In September 2008, the EPA filed a civil complaint against PPS in connection with the Pyramid Lake release. The complaint, which was filed in the Federal District Court for the Central District of California, Civil Action No. CV08-5768DSF(SSX), seeks the maximum permissible penalty under the relevant statutes of approximately $3.7 million. The EPA and DOJ have discretion to 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 may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We will defend against these charges. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty or fine that might be imposed by the EPA and DOJ, and intend to pursue discussions with the EPA and DOJ regarding such defenses and mitigating circumstances and factors. Although 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 on behalf of the EPA to resolve this matter have commenced.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE (and other petroleum product) contamination at the Pacific Atlantic Terminals LLC ("PAT") facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to $10 million. Both Exxon and GATX were prior owners of the terminal. We contend that Exxon and GATX are primarily responsible for the majority of the remediation costs. 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 are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the 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 mitigative costs or the imposition of fines and penalties. We have, for instance, recently settled numerous air permit violations alleged by the Bay Area Air Quality Management District.

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 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—Environmental, Health and Safety Regulation—Pipeline Safety/Pipeline and Storage Tank Integration Management." 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 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, 2008, our reserve for environmental liabilities totaled approximately $42 million, of which approximately $8 million is classified as short-term and $34 million is classified as long-term. At December 31, 2008, we have recorded receivables totaling approximately $4 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, 2009, the closing market price for our common units was $37.23 per unit and there were approximately 90,000 record holders and beneficial owners (held in street name). As of February 20, 2009, there were 122,911,645 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 Distributions(1)
	High	Low	
2008			
4th Quarter	$42.39	$23.25	$ 0.8925
3rd Quarter	48.36	35.68	0.8925
2nd Quarter	50.96	44.54	0.8875
1st Quarter	52.44	43.93	0.8650
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

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

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

Cash Distribution Policy

We will distribute 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 and Rainbow acquisitions, our general partner agreed to reduce the amounts due to it as incentive distributions. The total reduction in incentive distributions will be

$75 million. Following the distribution in February 2009, the aggregate remaining incentive distribution reductions are $31 million.

We paid $106 million to the general partner in incentive distributions in 2008. On February 13, 2009, we paid a quarterly distribution of $0.8925 per unit applicable to the fourth quarter of 2008, of which approximately $30 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. No such default has occurred. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Sources of Liquidity—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 2008, and we do not have any announced or existing plans to repurchase any of our common units.

Item 6. *Selected Financial Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2008, 2007, 2006, 2005 and 2004 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,				
	2008	2007	2006	2005	2004
	(in millions, except for per unit data)				
Statement of operations data:					
Total Revenues[1]	$30,061	$20,394	$22,445	$31,177	$20,975
Income before cumulative effect of change in accounting principle[2]	$ 437	$ 365	$ 279	$ 218	$ 133
Net Income	$ 437	$ 365	$ 285	$ 218	$ 130
Basic net income before cumulative effect of change in accounting principle[2]	$ 2.70	$ 2.54	$ 2.84	$ 2.77	$ 1.94
Basic net income after cumulative effect of change in accounting principle	$ 2.70	$ 2.54	$ 2.91	$ 2.77	$ 1.89
Diluted net income before cumulative effect of change in accounting principle[2]	$ 2.67	$ 2.52	$ 2.81	$ 2.72	$ 1.94
Diluted net income after cumulative effect of change in accounting principle	$ 2.67	$ 2.52	$ 2.88	$ 2.72	$ 1.89
Balance sheet data (at end of period):					
Total assets	$10,032	$ 9,906	$ 8,715	$ 4,120	$ 3,160
Total long-term debt	3,259	2,624	2,626	952	949
Total debt	4,286	3,584	3,627	1,330	1,125
Partners' capital	3,552	3,424	2,977	1,331	1,070
Other data:					
Maintenance capital investments	$ 81	$ 50	$ 28	$ 14	$ 11
Net cash provided by (used in) operating activities	$ 857	796	(276)	24	104
Net cash used in investing activities	$ (1,339)	(663)	(1,651)	(297)	(651)
Net cash provided by (used in) financing activities	$ 464	(124)	1,927	271	555
Declared distributions per limited partner unit[3]	$ 3.50	$ 3.28	$ 2.87	$ 2.58	$ 2.30

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Volumes[4][5][6]					
Transportation segment (average daily volumes in thousands of barrels):					
Tariff activities	2,851	2,712	2,106	1,799	1,486
Trucking	97	105	101	84	64
Transportation Segment Total	2,948	2,817	2,207	1,883	1,550
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	53	46	25	22	20
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet ("bcf"))	14	13	13	4	—
LPG processing (average daily throughput in thousands of barrels)	17	18	12	—	—
Facilities Segment Total (average monthly capacity in millions of barrels)	56	48	27	22	20
Marketing segment (average daily volumes in thousands of barrels):					
Crude oil lease gathering purchases	658	685	650	610	589
Refined products sales	26	11	N/A	N/A	N/A
LPG sales	103	90	70	56	48
Waterborne foreign crude oil imported	80	71	63	59	12
Marketing Segment Total	867	857	783	725	649

(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 and $136 million for 2005 and 2004, 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) and $1.98 ($1.98 diluted) for 2005 and 2004, respectively.

(3) 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.

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

(5) Effective with the second quarter of 2008, facilities segment volumes with respect to crude oil and refined products are reported based on total shell capacity to provide uniform comparisons with respect to our activities for these products. Previously, such volumes were reported based on a combination of shell capacity and working capacity depending on the terms of the third-party or intra-company lease agreements. Natural gas and LPG volumes, which consist primarily of underground storage facilities, reflect working capacity as that is the primary basis upon which such facilities are leased. Corresponding metrics for prior periods have been conformed to this uniform approach.

(6) Facilities total is calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

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
- Internal Growth Projects and Acquisitions
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- 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 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 and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. See "—Results of Operations—Analysis of Operating Segments" for further discussion.

Overview of Operating Results, Capital Spending and Significant Activities

During 2008, our operations provided solid growth over 2007 and 2006 levels. The growth was driven primarily by our fee based activities included in our Transportation and Facilities segments. Much of the growth in these segments resulted from expanding our asset base through acquisitions and our ongoing internal growth projects. Our Marketing segment provided a positive contribution, but was down from 2007 and 2006. Lease gathering margins were stronger in 2008 than 2007. However, the 2007 results benefited from a contango crude oil market structure (which existed during the first half of the year), favorable crude oil differentials and favorable LPG margins. Key items impacting 2008 include:

- Eight months' contributions to earnings from the Rainbow acquisition, which was completed in May 2008 for consideration of approximately $687 million, as well as increased earnings resulting from prior acquisitions and expansion activities.
- A net loss of $11 million resulting from inventory valuation adjustments partially offset by related net gains from derivative activities. This net loss includes a loss of $145 million resulting from a write-down of inventory to its net realizable value. That loss is partially offset by gains of $134 million on related derivatives. The inventory adjustment and the derivative gains were primarily the result of the significant decrease in crude oil and LPG prices that occurred during the second half of 2008.

- A net gain of $7 million related to other derivative activities.

- A gain of approximately $29 million related to the settlement of the foreign currency and linefill hedges entered into in conjunction with the Rainbow acquisition.

- Decreased earnings and increased expenses totaling an estimated $15 million to $20 million due to impacts of Hurricanes Gustav and Ike, both of which came through the Gulf Coast area during 2008.

- A gain of approximately $14 million resulting from the sale of our NYMEX seats and shares in NYMEX Holdings, Inc., which merged with CME Group Inc.

- Equity compensation plan expense of $24 million for 2008 compared to $49 million for the prior period. The decreased expense is primarily the result of the decrease in unit price for 2008 compared to the increase in unit price for 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence for most of 2007.

- The issuance of $600 million of senior notes for net proceeds of approximately $597 million and the issuance of approximately 7 million limited partner units for net proceeds of approximately $315 million.

Internal Growth Projects and Acquisitions

We completed a number of capital expansion projects and acquisitions in 2008, 2007 and 2006 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, investments in unconsolidated entities, internal growth projects and maintenance capital for the periods indicated (in millions):

	For the Year Ended December 31,		
	2008	2007	2006
Acquisition capital	$ 735	$125	$3,021
Investment in unconsolidated entities	37	9	44
Internal growth projects	491	525	332
Maintenance capital	81	50	28
	$1,344	$709	$3,425

Internal Growth Projects

Our 2008 projects included the construction and expansion of pipeline systems and crude oil storage and terminal facilities. The following table summarizes our 2008 and 2007 projects (in millions):

Projects	2008	2007
Salt Lake City expansion(1)	$154	$ 72
Patoka tankage(1)	56	30
Paulsboro tankage(1)	30	—
St. James—Phase III(1)	27	—
Fort Laramie tank expansion	20	12
St. James, Louisiana storage facility	17	82
Rangeland tankage(1)	12	—
Pier 400(2)	10	6
Kerrobert pumping project(1)	9	—
Other projects(3)	156	323
Total	$491	$525

(1) These projects will continue into 2009. See "—Liquidity and Capital Resources—Uses of Liquidity—Capital Expenditures and Distributions Paid to Unitholders and General Partner—2009 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. Does not include intangible expenditures of approximately $5 million for emission reduction credits.

(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. Businesses acquired impact our results of operations commencing on the effective date of each acquisition. Our ongoing acquisition and capital expansion activities are discussed further in "—Liquidity and Capital Resources" and in Note 3 to our

Consolidated Financial Statements. Information regarding acquisitions completed in 2008, 2007 and 2006 is set forth in the table below (in millions):

Acquisitions

Acquisition	Effective Date	Acquisition Price	Operating Segment
Rainbow	05/01/2008	$ 687	Transportation
San Pedro and other	11/13/2008	48	Facilities
2008 Total		$ 735	
Bumstead LPG Storage Facility	07/24/2007	$ 52	Facilities
Tirzah LPG Storage Facility	10/02/2007	54	Facilities
Other	Various	19	Transportation and Marketing
2007 Total		$ 125	
Pacific	11/15/2006	$ 2,456	Transportation, Facilities and Marketing
Andrews	04/18/2006	220	Transportation, Facilities and Marketing
SemCrude	05/01/2006	129	Marketing
BOA/CAM/HIPS	07/31/2006	130	Transportation
Products Pipeline	09/01/2006	66	Transportation
Other	Various	20	Transportation, Facilities and Marketing
2006 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, resulting in the issuance of approximately 22 million Partnership units. 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.

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 our 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. For the year ended December 31, 2008, we estimate that approximately 1%, 1%, 6% and 8% of annual revenues, cost of sales, operating income and net income, respectively, were recorded using purchase and sales estimates. Accordingly, a 10% variance from this estimate would impact the respective line items by less than 1% on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Mark-to-Market Accrual. In situations where we are required to mark-to-market derivatives pursuant to Statement of Financial Accounting Standards 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. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation 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 internal valuation 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 accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $8 million. 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 accordance with SFAS No. 141 "Business Combination," with each acquisition, we 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, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

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. 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.

At December 31, 2008, we compared our market capitalization to our book equity, to determine if there was an indicator of impairment. Although, our market capitalization exceeded the book value of our equity at December 31, 2008, we updated our goodwill impairment test due to the ongoing deterioration of the credit markets and the overall economic conditions. We determined that the fair value was greater than book value for all three reporting units, and therefore goodwill was not considered impaired. We will continue to monitor the market to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary. We did not have any goodwill impairments in 2008, 2007 or 2006. See Note 2 to our Consolidated Financial Statements for a discussion of goodwill.

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. (collectively, our "equity compensation plans"). 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.

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 (as adjusted for debt service costs and excluding special distributions funded by debt) 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 $24 million, $49 million and $43 million in 2008, 2007 and 2006, respectively, 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.

During 2008, an impairment of approximately $5 million was recognized for assets taken out of service. Impairments of approximately $1 million and less than $1 million were recognized during 2007 and 2006, respectively.

Recent Accounting Pronouncements

Recent Accounting Pronouncements

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

Results of Operations

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. See Note 15 to our Consolidated Financial Statements for a definition of segment profit (including an explanation of why this is a performance measure) and 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. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. 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. Intersegment rates are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expense and general and administrative overhead expenses between segments based on management's assessment of the business activities for the 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. We believe that the estimates with respect to these allocations are reasonable.

	For the Twelve Months Ended December 31,			Favorable (Unfavorable)			
				2008-2007		2007-2006	
	2008	2007	2006	$	%	$	%
	(In millions, except per unit data)						
Transportation segment profit	$ 445	$ 334	$ 200	$ 111	33 %	$ 134	67 %
Facilities segment profit	153	110	35	43	39 %	75	214 %
Marketing segment profit	221	269	228	(48)	(18)%	41	18 %
Total segment profit	819	713	463	106	15 %	250	54 %
Depreciation and amortization	(211)	(180)	(100)	(31)	(17)%	(80)	(80)%
Interest expense	(196)	(162)	(86)	(34)	(21)%	(76)	(88)%
Interest income and other income (expense), net	33	10	2	23	230 %	8	400 %
Income tax expense	(8)	(16)	—	8	50 %	(16)	N/A
Income before cumulative effect of change in accounting principle	437	365	279	72	20 %	86	31 %
Cumulative effect of change in accounting principle	—	—	6	—	—	(6)	(100)%
Net income	$ 437	$ 365	$ 285	$ 72	20 %	$ 80	28 %
Earnings per basic limited partner unit	$ 2.70	$ 2.54	$ 2.91	$ 0.16	6 %	$ (0.37)	(13)%
Earnings per diluted limited partner unit	$ 2.67	$ 2.52	$ 2.88	$ 0.15	6 %	$ (0.36)	(13)%
Basic weighted average units outstanding	120	113	81	7	6 %	32	40 %
Diluted weighted average units outstanding	121	114	82	7	6 %	32	39 %

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. The transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees.

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

Operating Results[1] (in millions, except per barrel amounts)	Year Ended December 31, 2008	2007	2006	Favorable (Unfavorable) 2008-2007 $	%	2007-2006 $	%
Revenues							
Tariff activities	$ 800	$ 654	$ 438	$ 146	22 %	$ 216	49 %
Trucking	127	117	96	10	9 %	21	22 %
Total transportation revenues	927	771	534	156	20 %	237	44 %
Cost and Expenses							
Trucking costs	(88)	(80)	(71)	(8)	(10)%	(9)	(13)%
Field operating costs (excluding equity compensation expense)	(331)	(288)	(201)	(43)	(15)%	(87)	(43)%
Equity compensation income (expense)—operations[2]	(1)	(5)	(5)	4	80 %	—	—
Segment G&A expenses (excluding equity compensation expense)	(56)	(50)	(43)	(6)	(12)%	(7)	(16)%
Equity compensation expense—general and administrative[2]	(11)	(19)	(16)	8	42 %	(3)	(19)%
Equity earnings in unconsolidated entities	5	5	2	—	—	3	150 %
Segment profit	$ 445	$ 334	$ 200	$ 111	33 %	$ 134	67 %
Maintenance capital	$ 54	$ 34	$ 20	$ 20	59 %	$ 14	70 %
Segment profit per barrel	$ 0.41	$ 0.34	$ 0.26	$ 0.07	21 %	$ 0.08	31 %

Average Daily volumes (in thousands of barrels per day)[3]	Year Ended December 31, 2008	2007	2006	Favorable (Unfavorable) 2008-2007 Volumes	%	2007-2006 Volumes	%
Tariff activities							
All American	45	47	49	(2)	(4)%	(2)	(4)%
Basin	377	378	332	(1)	—	46	14 %
Capline	219	235	160	(16)	(7)%	75	47 %
Line 63/Line 2000	147	175	20	(28)	(16)%	155	775 %
Salt Lake City Area Systems	93	101	14	(8)	(8)%	87	621 %
West Texas/New Mexico Area Systems[4]	372	369	403	3	1 %	(34)	(8)%
Manito	70	73	72	(3)	(4)%	1	1 %
Rainbow	129	—	—	129	N/A	—	N/A
Rangeland	58	63	24	(5)	(8)%	39	163 %
Refined products	109	109	24	—	—	85	354 %
Other	1,232	1,162	1,008	70	6 %	154	15 %
Tariff activities total	2,851	2,712	2,106	139	5 %	606	29 %
Trucking	97	105	101	(8)	(8)%	4	4 %
Transportation segment total	2,948	2,817	2,207	131	5 %	610	28 %

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

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

(3) 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.

(4) The volumes for the West Texas/New Mexico Area Systems previously included amounts for the Mesa system, which has been reclassified to "Other" for all periods presented.

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 2008 compared to 2007 and for 2007 compared to 2006. The significant variances in revenues and average daily volumes for 2008, 2007 and 2006 are discussed below:

- Acquisitions and Expansion Projects—Revenues and volumes for the year ended December 31, 2008 were impacted by the Rainbow acquisition, which occurred in May 2008. The Rainbow acquisition contributed approximately $50 million of additional tariff revenues and additional volumes of approximately 129,000 barrels per day for the year ended December 31, 2008.

  Revenues and volumes for the year ended December 31, 2007 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). Such acquisitions and systems brought into service contributed approximately $164 million of additional tariff revenues and additional volumes of approximately 541,000 barrels per day for the year ended December 31, 2007.

- Loss Allowance Revenue—As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Although there was a significant decline in the average price of crude oil during the fourth quarter of 2008, the average realized price per barrel related to our loss allowance revenues was higher during most of 2008 than it was in 2007. Additionally, volumes increased slightly for 2008 compared to 2007. As a result, loss allowance revenues increased by approximately $31 million for the year ended December 31, 2008 compared to the year ended December 31, 2007.

  In contrast, the average realized price per barrel related to our loss allowance revenues during 2007 was relatively comparable to the realized price per barrel for 2006; however, the volumes for 2007 increased significantly compared to the volumes for 2006. Therefore, loss allowance revenues increased by approximately $24 million for the year ended December 31, 2007 compared to the year ended December 31, 2006.

- Linefill Hedge—Revenues for the year ended December 31, 2008 were impacted by a gain of approximately $17 million related to the unwind of a linefill hedge entered into in conjunction with the Rainbow acquisition.

- Rate Increases—Rates increase on the majority of our domestic pipeline systems on July 1st of each year resulting in increased revenues year-over-year. Rates on our pipeline systems are increased through indexing by the FERC, by state and Canadian regulatory agencies and through market-based escalation.

- Hurricane Impact—Segment profit decreased by an estimated $3 million to $5 million due to impacts of Hurricanes Gustav and Ike, both of which came through the Gulf Coast area during the third quarter of 2008.

- Foreign Exchange—Revenues from our Canadian pipeline systems (other than Rainbow, as noted above) increased in 2007 compared to 2006 primarily due to the appreciation of Canadian currency. The average exchange rates for the years ended December 31, 2008, 2007 and 2006 were $1.07:1, $1.07:1 and $1.13:1, respectively.

- Trucking—Revenues for 2007 increased compared to 2006 due to trucking businesses that were acquired in both 2007 and 2006.

- Basin and Capline Pipeline Systems—Capline revenues and volumes were negatively impacted for 2008 compared to 2007 by the hurricanes as discussed above. There was an increase in revenues and volumes for 2007 compared to 2006 of approximately $30 million and 122,000 barrels per day on the Basin and Capline pipeline systems. The increase on the Basin system was primarily a result of new connection points that were constructed and placed in service in 2007 as well as an increase in short-haul volumes. The increase in the Capline pipeline system revenues and volumes is primarily related to an existing shipper that increased its movements of crude oil in 2007.

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) have increased in most categories for 2008 and 2007 due to various reasons including our continued growth through acquisitions, primarily related to the Rainbow acquisition, and expansion projects. The 2008 increased costs primarily relate to (i) utilities costs, which increased due to higher market prices, (ii) payroll and benefits and (iii) compliance with API 653 and pipeline integrity testing and maintenance requirements.

The most significant cost increases in 2007 compared to 2006 primarily related 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.

General and Administrative Expenses. General and administrative expenses have increased in 2008 compared to 2007 in most categories including (i) payroll, (ii) contract labor and consulting fees and (iii) taxes due to various reasons including our continued growth through acquisitions and expansion projects. Our G&A expenses (excluding equity compensation charges as discussed below) were impacted in 2007 compared to 2006 primarily as a result of acquisitions and expansion projects.

Equity Compensation Charges. Equity compensation charges decreased approximately $12 million in 2008 compared to 2007 primarily as a result of the decrease in unit price for 2008 compared to the increase in unit price for 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence for most of 2007. 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 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 an approximate 22% share in each system. The increase in 2007 compared to 2006 is due to the acquisitions of Frontier (in connection with the Pacific acquisition) and Settoon Towing in the fourth quarter of 2006.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in 2008 compared to 2007 is primarily due to increased investment applicable to in-line inspections and API 653 repairs in an effort to meet our 2009 compliance deadline (particularly on assets acquired from Pacific). The increase in maintenance capital for 2007 compared to 2006 was 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 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. The facilities segment generates revenue through a combination of month-to-month and multi-year leases and processing arrangements.

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

Operating Results[1] (in millions, except per barrel amounts)	For the Year Ended December 31, 2008	2007	2006	Favorable (Unfavorable) 2008-2007 $	%	2007-2006 $	%
Storage and terminalling revenues[1]	$ 270	$ 210	$ 88	$ 60	29 %	$ 122	139 %
Field operating costs	(104)	(84)	(39)	(20)	(24)%	(45)	(115)%
Segment G&A expenses (excluding equity compensation expense)	(18)	(18)	(14)	—	—	(4)	(29)%
Equity compensation expense—general and administrative[2]	(4)	(8)	(6)	4	50 %	(2)	(33)%
Equity earnings in unconsolidated entities	9	10	6	(1)	(10)%	4	67 %
Segment profit	$ 153	$ 110	$ 35	$ 43	39 %	$ 75	214 %
Maintenance capital	$ 23	$ 10	$ 5	$ 13	130 %	$ 5	100 %
Segment profit per barrel	$ 0.23	$0.19	$0.11	$ 0.04	21 %	$ 0.08	73 %

Volumes[3][4][5]	For the Year Ended December 31, 2008	2007	2006	Favorable (Unfavorable) 2008-2007 Volumes	%	2007-2006 Volumes	%
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	53	46	25	7	15 %	21	84%
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet ("bcf"))	14	13	13	1	8 %	—	—
LPG processing (average throughput in thousands of barrels per day)	17	18	12	(1)	(6)%	6	50%
Facilities segment total (average monthly capacity in millions of barrels)	56	48	27	8	16 %	21	78%

(1) Revenues include intersegment amounts.

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

(3) 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.

(4) Effective with the second quarter of 2008, facilities segment volumes with respect to crude oil and refined products are reported based on total shell capacity to provide uniform comparisons with respect to our activities for these products. Previously, such volumes were reported based on a combination of shell capacity and working capacity depending on the terms of the third-party or intra-company lease agreements. Natural gas and LPG volumes, which consist primarily of underground storage facilities, reflect working capacity as that is the primary basis upon which such facilities are leased. Corresponding metrics for prior periods have been conformed to this uniform approach.

(5) Facilities total 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 year and divided by the number of months in the year.

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 2008 compared to 2007 and for 2007 compared to 2006. The table below presents the significant variances in volumes and revenues (in millions) between 2008, 2007 and 2006:

	Volumes			Revenues
	Crude Oil, Refined Products and LPG Storage(1)	Natural Gas Storage(2)	LPG Processing(3)	
2008 compared to 2007				
Increase due to:				
Acquisitions(4)	2	—	—	$ 13
Expansions(5)	6	—	—	37
Other	(1)	1	(1)	10
Total variance	7	1	(1)	$ 60
2007 compared to 2006				
Increase due to:				
Acquisitions(6)	16	—	6	$ 98
Expansions(7)	3	—	—	12
Other	2	—	—	12
Total variance	21	—	6	$122

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

(2) Average monthly capacity (in bcf).

(3) Barrels per day (in thousands).

(4) Revenues and volumes for 2008 compared to 2007 were impacted by the Bumstead and Tirzah acquisitions in 2007 in addition to the San Pedro acquisition that we closed during the fourth quarter of 2008. The Bumstead acquisition was completed in the third quarter of 2007 and the Tirzah acquisition was completed in the fourth quarter of 2007.

(5) Expansion projects also resulted in an increase in revenues and volumes in 2008 compared to 2007. The Cushing, Martinez and St. James facilities all had significant expansion projects that were completed during 2008. Revenues for these facilities increased by a combined $37 million. Aggregate volumes increased by approximately 6 million barrels for 2008 at these facilities.

(6) 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 15 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 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.

(7) Expansion projects also resulted in an increase in revenues and volumes in 2007 compared to 2006. The St. James and Kerrobert expansion projects were completed during 2007. Aggregate revenues and volumes for these facilities increased by approximately $12 million and approximately 3 million barrels, respectively, for 2007.

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) have increased in most categories for 2008 and 2007 due to various reasons including our continued growth through acquisitions, primarily related to the Tirzah and Bumstead acquisitions completed during 2007 and the additional tankage added at Cushing, St. James and Martinez in 2008 and 2007. The 2008 increased costs primarily relate to (i) payroll and benefits, (ii) utilities costs, which increased primarily due to increased usage as well as higher market prices, (iii) unplanned maintenance projects at several facilities and (iv) additional regulatory accruals.

The increase for 2007 compared to 2006 relates to the operating costs associated with the Shafter processing facility that was acquired in April 2006, the Pacific acquisition that was completed in November 2006, and the Bumstead and Tirzah acquisitions that were completed in July 2007 and October 2007, respectively, as well as the St. James expansion project that was ongoing throughout 2007.

General and Administrative Expenses. Our G&A expenses (excluding equity compensation charges as discussed below) were impacted in 2007 and 2006 primarily as a result of acquisitions and expansions.

Equity Compensation Charges. Equity compensation charges decreased by approximately $4 million in 2008 compared to 2007 primarily as a result of the decrease in unit price for 2008 compared to the increase in unit price for 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence for most of 2007. Equity compensation charges 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 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.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital for 2008 is primarily due to maintenance at various terminals, including the Martinez, Richmond, LA Basin and Cushing terminals. The increase in 2007 was primarily due to additional maintenance expenditures arising from the Pacific acquisition.

Marketing Segment

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 purchase volumes, (ii) refined products volumes, (iii) LPG sales volumes and (iv) waterborne foreign crude oil 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:

Operating Results[1] (in millions, except per barrel amounts)	For the Year Ended December 31, 2008	2007	2006	Favorable (Unfavorable) 2008-2007 $	%	2007-2006 $	%
Revenues[2][3]	$ 29,350	$ 19,858	$ 22,061	$ 9,492	48 %	$(2,203)	(10)%
Purchases and related costs[4][5]	(28,873)	(19,366)	(21,641)	(9,507)	(49)%	2,275	11 %
Field operating costs	(185)	(154)	(137)	(31)	(20)%	(17)	(12)%
Segment G&A expenses (excluding equity compensation charge)	(63)	(52)	(39)	(11)	(21)%	(13)	(33)%
Equity compensation charge—general and administrative[6]	(8)	(17)	(16)	9	53 %	(1)	(6)%
Segment profit[3]	$ 221	$ 269	$ 228	$ (48)	(18)%	$ 41	18 %
Net gains/(losses) related to inventory valuation adjustments and derivative activities[3]	$ (4)	$ (27)	$ (4)	$ 23	85 %	$ (23)	(575)%
Maintenance capital	$ 4	$ 6	$ 3	$ (2)	(33)%	$ 3	100 %
Segment profit per barrel[7]	$ 0.70	$ 0.86	$ 0.80	$ (0.16)	(19)%	$ 0.06	7 %

Average Daily Volumes[8] (in thousands of barrels per day)	For the Year Ended December 31, 2008	2007	2006	Favorable (Unfavorable) 2008-2007 Volumes	%	2007-2006 Volumes	%
Crude oil lease gathering purchases	658	685	650	(27)	(4)%	35	5%
Refined products sales	26	11	N/A	15	136 %	11	N/A
LPG sales	103	90	70	13	14 %	20	29%
Waterborne foreign crude oil imported	80	71	63	9	13 %	8	13%
Marketing segment total	867	857	783	10	1 %	74	9%

(1) Revenues and costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $4,762 million for the year ended December 31, 2006. This amount includes 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) Gains/(losses) from derivative activities net of inventory valuation adjustments.

(4) Includes purchases associated with buy/sell arrangements of $4,795 million for the year ended December 31, 2006. This amount includes 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 hedged inventory purchases of approximately $21 million, $44 million and $49 million for the years ended December 31, 2008, 2007 and 2006, respectively.

(6) Equity compensation expense related to our equity compensation plans.

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

(8) 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 2008, 2007 and 2006 are discussed below.

- Generally we consider the market to be favorable and are able to optimize and enhance the margins of our gathering and marketing activities when there is a high level of volatility in the market combined with favorable basis differentials and a steep contango or backwardated market structure. There was volatility in the outright price of crude oil during the last three years. The NYMEX benchmark price of crude oil ranged from approximately $32 to $147 per barrel, $50 to $99 per barrel and $55 to $78 per barrel for 2008, 2007 and 2006, respectively. In addition, there was volatility in the market structure in each of the last three years; 2008 and 2007 fluctuated between a contango market and a backwardated market but 2006 was in contango for the whole year. The monthly timespread of prices averaged approximately $0.21 (contango) for 2008, versus $0.32 (contango) for 2007 and an average contango spread of $1.22 for 2006. 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. 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. In the fluctuating market structure for 2008 and 2007, we were able to optimize the margins of our gathering and marketing activities. Lease gathering margins were stronger in 2008 than 2007. However, the 2007 results benefited from a contango crude oil market structure (which existed during the first half of the year), favorable crude oil differentials and favorable LPG margins.

- Results from our LPG operations were lower in 2008 as compared to the respective period of 2007. Our LPG operations operate on an April to March storage season and the timing of recognizing earnings over that season may vary from year to year based on the sales price of contracts presented for delivery and the average costing of inventory. Results for 2007 benefited from a strong first quarter that included profits from the end of the 2006 - 2007 storage season. Our LPG operations were also impacted by a foreign exchange unrealized loss, which we expect to recover through higher margins in future periods.

- Results for 2008 include a net loss of $11 million resulting from inventory valuation adjustments partially offset by related net gains from derivative activities. This net loss includes a loss of $145 million resulting from a write-down of inventory to its net realizable value, which is partially offset by gains of $134 million on related derivatives. The inventory adjustment and the derivative gains were primarily the result of the significant decrease in crude oil and LPG prices that occurred during the second half of 2008. Revenues for 2008 also include a net gain of $7 million related to other derivative activities. Revenues for 2007 include losses related to derivative activities of approximately $27 million. Revenues for 2006 include losses related to derivative activities of approximately $4 million. Purchases and related costs for 2006 include an inventory valuation adjustment, which resulted in a loss of approximately $6 million. See Note 6 to our Consolidated Financial Statements for a discussion of our derivative related activities.

- Segment profit for the year ended December 31, 2008 was also negatively impacted by an estimated $10 million to $15 million due to reduced volumes and other impacts of Hurricanes Gustav and Ike.

- Our revenues and purchases and related costs decreased for 2007 compared to 2006 due to the adoption in the second quarter of 2006 of Emerging Issues Task Force Issue No. 04-13 ("EITF 04-13"), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." 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.

- During 2007 and 2006, 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.

Field Operating Costs. Field operating costs increased in 2008 compared to 2007, primarily due to increases in (i) transportation-related costs, including fuel, third-party trucking fees and drivers' salaries and (ii) the number of trucks and trailers under operating leases versus capital leases. Field operating costs increased in 2007 compared to 2006, primarily as a result of increases in (i) third-party trucking fees as a result of 2006 acquisitions, (ii) fuel costs resulting from higher market prices and (iii) maintenance costs as a result of 2006 acquisitions.

General and Administrative Expenses. General and administrative expenses increased for 2008 compared to 2007 primarily as a result of increases in payroll costs and consulting fees. General and administrative expenses increased for 2007 compared to 2006 primarily as a result of increased payroll and benefits (partly due to the retirement of an executive), as well as acquisitions and internal growth.

Equity Compensation Charges. Equity compensation charges decreased by approximately $9 million in 2008 compared to 2007 primarily as a result of the decrease in unit price during 2008 compared to the increase in unit price for 2007. The impact of the change in unit price was partially offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence for most of 2007. Equity compensation charges increased approximately $1 million in 2007 compared to 2006 principally as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $211 million for the year ended December 31, 2008 compared to $180 million and $100 million for the years ended December 31, 2007 and 2006, respectively. The increases in 2008 and 2007 related primarily to an increased amount of depreciable assets stemming from our acquisition activities and internal growth projects. Amortization of debt issue costs was $4 million, $3 million and $3 million in 2008, 2007 and 2006, respectively.

Included in depreciation expense for the years ended December 31, 2008, 2007 and 2006 is a net gain of $6 million, a net loss of approximately $7 million and a net gain of approximately $2 million, respectively, recognized upon disposition of certain inactive assets. Also included within depreciation expense for the year ended December 31, 2008 is an impairment of approximately $5 million for assets taken out of service.

Interest Expense

Interest expense was $196 million for the year ended December 31, 2008, compared to $162 million and $86 million for the years ended December 31, 2007 and 2006, 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,					
	2008		2007		2006	
	Total	% of Total	Total	% of Total	Total	% of Total
Fixed rate senior notes[1]	$ 3,028	87%	$ 2,625	95%	$ 1,336	92%
Borrowings under our revolving credit facilities[2]	456	13%	150	5%	118	8%
Total	$ 3,484		$ 2,775		$ 1,454	

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

(2) Excludes borrowings under our senior secured hedged inventory facility and the short-term portion of our senior unsecured revolving credit facility, as the associated interest expense is recorded in crude oil, refined products and LPG purchases and related costs.

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2008 and 2007 (in million, except for percentages):

	$	Average LIBOR Rate	Weighted Average Interest Rate[1]
Interest expense for the year ended December 31, 2006	$ 86	5.0%	6.1%
Impact of issuance and assumption of notes related to the Pacific acquisition[2]	77		
Impact of issuance of senior notes[3]	6		
Impact of increased borrowings under credit facilities[4]	2		
Impact of increased capitalized interest	(8)		
Other	(1)		
Interest expense for the year ended December 31, 2007	$162	5.2%	6.3%
Impact of issuance of senior notes[5]	27		
Impact of increased borrowings under credit facilities[4]	5		
Impact of increased capitalized interest	(3)		
Other	5		
Interest expense for the year ended December 31, 2008	$196	2.7%	5.9%

(1) Excludes commitment and other fees.

(2) In October 2006, we issued $1.0 billion senior notes to partly finance the Pacific acquisition in November 2006. In connection with the Pacific acquisition, we also assumed $400 million senior notes from Pacific.

(3) In May 2006, we issued $250 million of senior notes.

(4) The change primarily reflects varying borrowing requirements for inventory-related borrowings and other working capital items and changes in LIBOR rates.

(5) The $600 million senior notes were issued in April 2008 in connection with the Rainbow acquisition.

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 $21 million, $44 million and $49 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Interest Income and Other, Net

Interest income and other, net increased by approximately $23 million for the year ended December 31, 2008, compared to the year ended December 31, 2007 primarily due to (i) a gain of $14 million resulting from the sale of our NYMEX seats and shares in NYMEX Holdings, Inc., which merged with CME Group Inc. and (ii) a gain of $11 million on the foreign currency hedge and commodity price risk hedge that we entered into in connection with the Rainbow acquisition.

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 NYMEX Holdings, Inc. and (ii) the change in fair value of our interest rate swaps.

Income Tax Expense

Excluding the $10 million impact of the initial adoption of the revised Canadian tax laws in 2007, our income tax expense increased by $2 million in 2008 compared to 2007 primarily due to the Rainbow acquisition. Income tax expense was $16 million for the year ended December 31, 2007 primarily due to revised rules on Canadian taxation on certain flow-through entities and the introduction of the Texas margin tax. There was no income tax in 2006. See Note 7 to our Consolidated Financial Statements for further discussion.

Outlook

During 2008, we grew our business by expanding our asset base through approximately $735 million of acquisitions and $491 million of internal growth projects. In 2009, we intend to spend approximately $295 million on internal growth projects. Several of the larger storage tank projects for 2008 and 2009, such as the construction or expansion of the Patoka, St. James and Cushing 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 and the associated diluent requirements to facilitate its movement. We also believe there are opportunities for us to grow our LPG business and the natural gas storage business of PAA/Vulcan. In late 2008, PAA/Vulcan's management team was further strengthened and a major gas storage project was placed into partial commercial operation. The management team of PAA/Vulcan has been charged with developing the company into a solid, stand alone business through organic growth, acquisitions and greenfield development projects.

We intend to continue to develop our inventory of projects for implementation beyond 2009 throughout all of our product and growth platforms, and to pursue potential acquisitions of assets and businesses within our existing areas of operation as well as potential acquisitions of other complementary assets and businesses. These efforts may involve assets that, if constructed or acquired, could have a material effect on our financial condition and results of operations. Although we expect any such capital expenditures to be accretive in the long term, we can give no assurance that our current or future expansion or acquisition efforts will be completed, if at all, on terms considered favorable to us, nor that our expectations will ultimately be realized.

During 2008, the financial markets were extremely volatile and the global economy substantially weakened. Many well-known and previously sound U.S. financial institutions failed or were forced into mergers. The U.S. government and governments around the world have taken significant actions in response, including an attempt to provide liquidity and stability to the financial markets by providing government assistance to some of the largest financial institutions in the world. Moreover, the energy markets experienced remarkable volatility, with the prices of crude oil and refined products reaching historically high levels during the first seven months of 2008, then dropping precipitously to much lower levels during the remainder of the year.

Despite the chaotic and unstable market conditions, we believe we have access to equity and debt capital—albeit at a higher cost and with greater execution risk than previously experienced—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 will not be unaffected by challenging economic and capital markets conditions, we believe that the current market environment may enhance our competitive positioning relative to other smaller, non-investment grade competitors.

Although we believe our business strategy is designed to manage a volatile environment, and that our asset base strategically positions us to benefit from certain of these developments, there can be no assurance that we will not be negatively affected by this volatility or the challenging capital markets conditions, or that our acquisition and expansion efforts will be successful. See Item 1A. "Risk Factors—Risks Related to Our Business."

Liquidity and Capital Resources

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At December 31, 2008, we had a working capital deficit of approximately $364 million, approximately $764 million of availability under our committed revolving credit facility and approximately $245 million of availability under our committed hedged inventory facility. Usage of the credit facilities is subject to ongoing compliance with covenants. We believe we are currently in compliance with all covenants.

We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position is strong and we have sufficient liquidity; however, further disruptions in the financial markets and significant energy price volatility that adversely affect our business may have a material adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. "Risk Factors" for further discussion regarding such risks that may impact our liquidity and capital resources.

In light of the recent decline in the credit markets and overall market turmoil, we have taken the following proactive and preemptive steps to maintain our financial strength and flexibility and the ability to generate baseline cash flow:

- We have increased the amount of storage capacity leased to third parties by leasing storage capacity on certain newly constructed tanks and certain tanks previously reserved for our proprietary use, which reduced our potential working capital requirements.
- We have pre-funded or contemporaneously funded acquisitions and our capital expansion programs in order to maintain a strong balance sheet and high levels of liquidity. As a result, we have the ability to execute our capital plans through 2009 without reliance on the financial markets for incremental debt or equity capital.
- We have reduced our forecasted expansion capital spending for 2009 to approximately $295 million from $491 million in 2008.

Cash Flow from Operations

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. In addition, our cash flow from operations may be impacted by the timing of settlement of our derivative activities. Gains and losses from settled instruments that qualify as effective cash flow hedges are deferred in AOCI, but may impact operating cash flow in the period settled.

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. During such market conditions, 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.

Our cash flow from operations are significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During 2008, we increased the amount of our inventory; however, these volumetric increases were offset by lower prices for our inventory stored at the end of the year compared to prior year amounts. The net proceeds received during the year were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities. The settlement of gains on derivatives that have been deferred in AOCI also had a significant positive impact in 2008 on our operating cash flows. During 2007 we reduced our overall inventory levels as we liquidated inventory that had been stored in the contango market. The proceeds from liquidating the inventory were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities. 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.

Credit Facilities and Long-Term Debt

At December 31, 2008, we had approximately $0.8 billion of available borrowing capacity under our $1.6 billion committed revolving credit facility. Of the capacity we utilized at December 31, 2008, approximately $51 million was associated with outstanding letters of credit and the remainder was borrowed. The majority of these borrowings related to LPG inventory that is scheduled to be sold over the next six months. This credit facility, among other things, has a maturity date of July 2012, contains no Material Adverse Change language and can be expanded to $2.0 billion, subject to additional lender commitments. In addition this revolving credit facility includes broad participation from 24 financial institutions, with no one institution holding more than 10% or less than 2% of the total facility. See Note 4 to our Consolidated Financial Statements.

At December 31, 2008, we had approximately $245 million of availability under our $525 million committed hedged inventory facility. The facility's committed amount may be increased to $1.2 billion, subject to obtaining additional commitments from lenders. This facility is a committed 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. The facility will mature on an annual basis beginning in November 2009.

We also have several issues of senior debt outstanding that total $3.2 billion, excluding premium or discount, and range in size from $150 million to $600 million and mature at various dates through 2037. Approximately $175 million of these senior notes are due in August 2009. Since we have the ability and intent to refinance these notes, they are classified as long-term debt within our balance sheet.

Our credit agreements and the indentures governing our senior notes contain cross-default provisions. 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. See Note 4 to our Consolidated Financial Statements.

Equity and Debt Financing Activities

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.

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, 2008, we have $2.0 billion of unissued securities remaining available under this registration statement.

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.

2008		2007		2006	
Units	Net Proceeds(1)	Units	Net Proceeds(1)	Units	Net Proceeds(1)(2)
6,900,000	$ 315	6,296,172	$ 383	13,389,562	$ 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. During the last three years we completed the sale of senior unsecured notes as summarized in the table below (in millions).

Year	Description	Maturity	Face Value	Net Proceeds[1]
2008	6.5% Senior Notes issued at 99.424% of face value	May 2018	$ 600	$ 597
2006	6.125% Senior Notes issued at 99.56% of face value	January 2017	$ 400	$ 398
	6.65% Senior Notes issued at 99.17% of face value	January 2037	$ 600	$ 595
	6.7% Senior Notes issued at 99.82% of face value	May 2036	$ 250	$ 250

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

Credit Facilities. During the year ended December 31, 2008, we had net working capital and hedged inventory borrowings of approximately $90 million. These net borrowings were used primarily for purchases of LPG inventory that was stored. 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 2006, we had net working capital and hedged inventory borrowings of approximately $320 million. These net borrowings were used primarily for purchases of crude oil inventory that was stored. For further discussion related to our credit facilities and long-term debt, see "—Credit Facilities and Long-Term Debt" above.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

We use cash primarily for our acquisition activities, internal growth projects and distributions paid to our 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. See "—Internal Growth Projects and Acquisitions" for further discussion for such capital expenditures.

Acquisitions. 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.

2009 Capital Expansion Projects. The vast majority of funding for our 2009 capital program will be provided by a combination of cash flow in excess of partnership distributions, proceeds associated with pending asset sales and planned reductions in crude oil and LPG inventories, as we expect prices to be lower in 2009 than they were in 2008. This will allow us to fund these capital projects without need to access the capital markets for equity or debt. Our 2009 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects	
St. James Phase III(1)	$ 85
Kerrobert pumping project	34
Cushing—Phase VII	29
Rangeland tankage and connections	29
Nipisi storage and truck terminal	20
Patoka tankage	20
Paulsboro tankage	13
Other projects, including acquisition related expansion projects(2)	65
	$295

(1) Includes a dock and condensate tanks.

(2) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2008.

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. We paid our quarterly distribution for the fourth quarter of 2008 on February 13, 2009. Due to the unstable and uncertain financial markets, the distribution was consistent with the distribution in the third quarter of 2008 but achieved a year-over-year distribution increase of 5%, which is within the range of our 2008 target for distribution growth of 5% - 8%. We will continue to monitor the financial market conditions as they evolve and it is our intent to maintain an appropriate balance between the near-term benefits of distribution growth and the long-term benefits of retaining excess cash flow during such challenging times for capital formation. See Note 5 to our Consolidated Financial Statements for details of distributions paid. Also, see Item 5. "Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy" for additional discussion on distribution thresholds.

Upon closing of the Pacific and Rainbow acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. See Note 5 to our Consolidated Financial Statements for details related to the general partner's incentive distributions reduction.

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.

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 purchases on the one hand and sales and future delivery obligations on the other. 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, 2008 (in millions).

	Total	2009	2010	2011	2012	2013	2014 and Thereafter
Long-term debt and interest payments(1)	$ 5,811	$ 378	$ 198	$ 198	$ 394	$ 431	$ 4,212
Leases(2)	408	57	46	40	35	26	204
Other long-term liabilities(3)	110	36	27	9	13	3	22
Subtotal	6,329	471	271	247	442	460	4,438
Crude oil and LPG purchases(4)	4,344	3,277	519	312	229	7	—
Total	$ 10,673	$ 3,748	$ 790	$ 559	$ 671	$ 467	$ 4,438

(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, 2008, 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 (i) storage, (ii) rights-of-way, (iii) office rent and (iv) trucks used in our gathering activities.

(3) Excludes a non-current liability of approximately $72 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, 2008 and 2007, we had outstanding letters of credit of approximately $51 million and $153 million, respectively. The change in the value of outstanding letters of credit is impacted primarily by the fluctuation of market prices and the timing of foreign cargos purchased.

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 our 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 2008 and 2007, we made additional contributions of $37 million and $9 million to PAA/Vulcan, respectively. During 2008, we received distributions of $7 million from PAA/Vulcan; there were no such distributions received during 2007. Vulcan Gas Storage made the same net contribution as we did during 2008 and 2007. Such contributions and distributions did not result in an increase or decrease to our ownership interest. See Note 9 to our Consolidated Financial Statements.

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 (now known as PAA Natural Gas Storage, LLC) in 2005, 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.

Investments in Unconsolidated Entities

We have invested in entities that are not consolidated in our financial statements. Certain of these entities are borrowers under credit facilities. We are neither a co-borrower nor a guarantor under any such facilities. In the case of PAA/Vulcan, we have agreed, along with our co-venturer, to make future capital contributions (a maximum of $17.5 million in the aggregate to our share) for further contribution to Pine Prairie. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2008 (unaudited, in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
PAA/Vulcan	Natural Gas Storage	50%	$812	$ 47	$418
Settoon Towing	Barge Transportation Services	50%	$ 85	$ —	$ 54
Frontier	Crude Oil Pipeline	22%	$ 25	$ 1	$ —
Butte	Crude Oil Pipeline	22%	$ 12	$ 1	$ —

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

We are exposed to various market risks, including volatility in (i) commodity prices for crude oil, refined products, natural gas and LPG, (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 referenced below, our approved strategies are intended to mitigate and manage 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 use derivative instruments and physical delivery contracts to 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, options and swaps traded on the NYMEX, ICE and in 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 referenced 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. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time. 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 and a substantially lesser amount for LPG.

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.

All of our open commodity price risk derivatives at December 31, 2008 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below (in millions):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ (10)	$ 22
Swaps and options contracts	174	59
LPG and other:		
Futures contracts	(24)	(3)
Swaps, options and other contracts[1]	(170)	(21)
Total Fair Value	$ (30)	

(1) Amount includes approximately $46 million associated with LPG and natural gas physical contracts not eligible for the normal purchase and sale scope exception under SFAS 133.

The fair value of our exchange-traded contracts is based on quoted market prices obtained from the NYMEX or ICE. The fair value of our over-the-counter 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. See Note 6 to our Consolidated Financial Statements for further discussion. Price-risk sensitivities were calculated by assuming an across-the-board 10 percent decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10 percent change in near-term crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

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. Substantially all of our variable rate debt at December 31, 2008, approximately $1 billion, is short-term debt and is subject to interest rate re-sets, which range from a week to a month. The average interest rate of 1.4% is based upon rates in effect at December 31, 2008. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates. 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 our open foreign currency instruments is an unrealized gain of $13 million as of December 31, 2008. A ten percent decrease in the exchange rate (Canadian dollars to U.S. dollars) would result in an increase of approximately $12 million to the fair value of our foreign currency derivatives. 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.

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, 2008. 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 2008 that has not previously been reported.

PART III

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

Partnership Management and Governance

As is the case with many publicly traded partnerships, we do not directly have officers, directors or employees. Our operations and activities are managed by 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, in most instances involving payment liability, 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 Fourth Amended and Restated Limited Liability Company Agreement of GP LLC (the "GP LLC Agreement"), two 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. The remaining five seats are elected, and may be removed, by a majority of the membership interest. Directors filling three of these five "at large" seats must be independent. In August 2008, a wholly owned subsidiary of Occidental Petroleum Corporation ("Oxy") acquired a 10% membership interest in GP LLC directly from other existing members. As a result of this transaction, Oxy has the right to designate an individual to attend Board meetings in an observer capacity. Under certain circumstances involving changes in upper-level management, Oxy will have the right to designate a director to serve on the Board and the authorized number of Board members will be expanded to a total of nine.

In August 2005, a former member's 19% interest in the general partner was sold pro rata to the other general partner owners, which increased Vulcan Energy's ownership interest from 44% to greater than 50%. 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, in effect, would allow Vulcan Energy unilaterally to elect six of the eight board seats: the Vulcan Energy designee and the five "at large" seats (subject to the requirement that three of the "at large" directors meet the independence requirements set forth in 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 consisting of at least three members, all of whom 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 (Everardo Goyanes, Arthur L. Smith and J. Taft 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:

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 2008, the amount paid to LEH by Plains Marketing was approximately $0.4 million (net of severance taxes). The board has determined that the transactions with LEH do not compromise Mr. Goyanes' independence.

Arthur L. Smith, a member of our audit committee, is a director of Pioneer Natural Resources GP LLC, the general partner 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 is not an officer of PSE or Pioneer and does not participate in operational decision making. In 2008, the amount paid to Pioneer and its affiliates by Plains Marketing was approximately $566.5 million. The board has determined that the transactions with PSE and Pioneer do not compromise Mr. Smith's independence.

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 W. Lance Conn, Gary R. Petersen and Robert V. 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 2008. 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 employees other than executive 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, two 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, the GP LLC Agreement and our partnership agreement.

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. For example, a conflicts committee may be asked from time to time to review certain aspects of our joint venture with PAA/Vulcan. See Item 13. "Certain Relationships and Related Transactions, and Director Independence—Transactions with Related Persons—Review, Approval or Ratification of Transactions with Related Persons."

Meetings and Other Information

During the last fiscal year our board of directors had eight regularly scheduled and special meetings, our audit committee had 11 meetings, our compensation committee had two formal meetings 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 standing committees have charters. Our committee charters and governance guidelines, as well as our Code of Business Conduct and our Code of Ethics for Senior Financial Officers, which apply to our principal executive officer, principal financial officer and principal accounting officer, are available on our Internet website at *http://www.paalp.com*. Print versions of the foregoing are available to any unitholder without charge, 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 the firm's 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 applicable requirements of the Public Company Accounting Oversight Board regarding PricewaterhouseCoopers LLP's communications with the audit committee concerning independence, 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, 2008 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, 2008 for filing with the SEC.

Robert V. Sinnott, *Chairman*
W. Lance Conn
Gary R. Petersen

Compensation Committee Interlocks and Insider Participation

Messrs. Conn, Petersen and Sinnott served on the compensation committee during 2008. David N. Capobianco, a former director, served on the compensation committee for a portion of 2008. During 2008, 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. Conn, 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. Two 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 12/31/08)	Position(1)
Greg L. Armstrong*(2)	50	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	51	President and Chief Operating Officer
Phillip D. Kramer*	52	Executive Vice President
W. David Duckett*	53	President—PMC (Nova Scotia) Company
Mark J. Gorman*	54	Senior Vice President—Operations and Business Development
Alfred A. Lindseth	39	Senior Vice President—Technology, Process & Risk Management
Al Swanson*	44	Senior Vice President and Chief Financial Officer
John P. vonBerg*	54	Senior Vice President—Commercial Activities
Stephen L. Bart	48	Vice President—Operations of PMC (Nova Scotia) Company
David Craig	51	Executive Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Ralph R. Cross	53	Vice President—Corporate Development and Transportation Services of PMC (Nova Scotia) Company
A. Patrick Diamond	36	Vice President
Lawrence J. Dreyfuss	54	Vice President, General Counsel—Commercial & Litigation and Assistant Secretary
Roger D. Everett	63	Vice President—Human Resources
James B. Fryfogle	57	Vice President—Refinery Supply
M.D. (Mike) Hallahan	48	Vice President—Crude Oil of PMC (Nova Scotia) Company
Bill Harradence	55	Vice President—Human Resources of PMC (Nova Scotia) Company
Jim G. Hester	49	Vice President—Acquisitions
John Keffer	49	Vice President—Terminals
Charles Kingswell-Smith	57	Vice President and Treasurer
Mike Mikuska	40	Vice President—Business Development of PMC (Nova Scotia) Company
Tim Moore*	51	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	51	Vice President—Engineering
John F. Russell	60	Vice President—West Coast Projects
Robert M. Sanford	59	Vice President—Lease Supply
Tina L. Val*	39	Vice President—Accounting and Chief Accounting Officer
Troy E. Valenzuela	47	Vice President—Environmental, Health and Safety
Sandi Wingert	38	Vice President—Accounting of PMC (Nova Scotia) Company
David E. Wright	63	Vice President
Ron F. Wunder	40	Vice President—LPG of PMC (Nova Scotia) Company
W. Lance Conn(2)	40	Director and Member of Compensation Committee
Everardo Goyanes	64	Director and Member of Audit** Committee
Gary R. Petersen	62	Director and Member of Compensation Committee
Robert V. Sinnott(2)	59	Director and Member of Compensation** Committee
Arthur L. Smith	56	Director and Member of Audit and Governance** Committees
J. Taft Symonds	69	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 two of the owners of our general partner each have the right to appoint a member of our board of directors. Mr. Conn 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. Sinnott has been appointed by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is President. The remaining directors were elected by a majority of the membership interest. 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. and 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 since November 2008 and previously served as Executive Vice President and Chief Financial Officer from our formation in 1998 until November 2008. 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. He is also a director of Crusader Energy Group Inc., an oil and gas company engaged in drilling for and producing oil and gas.

W. David Duckett has served as 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.

Mark J. Gorman has served as Senior Vice President—Operations and Business Development since August 2008. He previously served as Vice President from November 2006 until August 2008. 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. Mr. Gorman is also a director of Settoon Towing, Butte and Frontier.

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 and Chief Financial Officer since November 2008. He previously served as Senior Vice President—Finance from August 2008 until November 2008 and as Senior Vice President—Finance and Treasurer from August 2007 until August 2008. 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.

John P. vonBerg has served as Senior Vice President—Commercial Activities since August 2008. Previously he served as Vice President—Commercial Activities from August 2007 until August 2008 and 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.

Stephen L. Bart has served as 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.

David Craig has served as Executive Vice President and Chief Financial Officer of PMC (Nova Scotia) Company since June 2008. Prior to joining our Canadian operations, Mr. Craig was with Nexen Inc. from 2004 to June 2008, where he served in various capacities, including most recently as Vice President of natural gas marketing. From 1999 until 2004, he was with Apache Canada Ltd., with responsibilities in the areas of gas marketing and finance. Mr. Craig has over 25 years of experience in the energy industry in various financial roles (including accounting, planning, treasury, and mergers & acquisitions) as well as natural gas marketing.

Ralph R. Cross has served as Vice President of Corporate 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.

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.

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.

Charles Kingswell-Smith has served as Vice President and Treasurer since August 2008. Mr. Kingswell-Smith previously served as Managing Director of GE Energy Financial Services from January 2008 to July 2008 and as Managing Director with Merrill Lynch Capital from March 2007 until January 2008. Prior to joining Merrill Lynch Capital, Mr. Kingswell-Smith spent 12 years in the energy banking business with JPMorgan Chase and BankOne.

Mike Mikuska has served as Vice President, Business Development of PMC (Nova Scotia) Company since September 2008. Mr. Mikuska has been with PMC and its predecessor CANPET Energy Group Inc. since 1995 and has served in various commercial and development roles over that time.

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 M. 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.

Sandi Wingert has served as Vice President, Accounting of PMC (Nova Scotia) Company since February 2008. She has been with PMC and its predecessor CANPET Energy Group Inc. for eight years acting as Controller. Prior to joining our Canadian operations, Sandi held various accounting roles with Koch Petroleum and Ernst & Young.

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.

W. Lance Conn has served as a director of our general partner since November 2008. Since July 2004, Mr. Conn has served as the President of Vulcan Capital, the investment group of Vulcan Inc., the investment and project management company that oversees a diverse multi-billion dollar portfolio of investments by Paul G. Allen, where Mr. Conn has served as Executive Vice President for Investment Management. Mr. Conn also sits on the boards of Charter Communications Inc., Vulcan Energy GP Holdings Inc., Vulcan Energy Corporation, PAA/Vulcan and Digeo Inc., and is a former director of Oxygen Media. He also serves as a director on the National Fish and Wildlife Foundation, a non-profit corporation. He serves as an advisory director for Makena Capital Management and an advisor to Global Endowment Management. Prior to joining Vulcan, Mr. Conn worked for America Online, where he served in various senior business and corporate development roles in the United States and Europe. Prior to AOL, Mr. Conn was an attorney with the Shaw Pittman law firm in Washington, D.C. Mr. Conn holds a J.D. from the University of Virginia, a master's degree in history from the University of Mississippi and an A.B. in history from Princeton University.

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 degrees 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. He is a director of Pioneer Natural Resources GP LLC, the general partner of Pioneer Southwest Energy Partners, L.P. 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). 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 and serves as a director of Howard Supply Company LLC and Schilling Robotics LLC. 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 and 4 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 2008.

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, other than expenses related to the Class B units of Plains AAP, L.P.

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 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 objectives. 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 generally competitive with the narrower universe of large-cap MLP peers, but are moderate relative to the broad spectrum of energy industry competitors for similar talent.

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 Mr. vonBerg was eligible to participate in 2008, 2007 and 2006. Mr. Kramer will also be eligible to participate in this program beginning in 2009. 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 require 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.

The Class B units are subject to restrictions on transfer and generally become incrementally "earned" (entitled to participate in distributions) upon achievement of certain performance thresholds. As of February 10, 2009, 25% of the outstanding Class B units had been earned.

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 (subject to certain exceptions) prior to January 1, 2016. A portion of unvested Class B units will vest (no longer be subject to the call right) upon a change of control. 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 CEO and General Counsel and provided to the compensation committee.

Whenever compensation is used as an incentive for performance, there is the potential that management might be motivated to take unnecessary or excessive risks to reach the performance thresholds. This potential is more pronounced with short-term incentives, particularly when the measure of performance is unsustainable or inconsistent with longer-term goals. Conversely, long-term incentives blended with consistent short-term rewards lessen the potential for misdirected motivation.

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 potential for rewards yet to come. We believe our compensation philosophy as implemented by application of the three primary compensation elements (i) aligns the interests of our Named Executive Officers with our unitholders, (ii) positions us to achieve our business goals, and (iii) effectively encourages the exercise of sound judgment and risk-taking that is conducive to creating and sustaining long-term value. We believe the processes employed by the compensation committee and the board in applying the elements of compensation (as discussed in more detail below) provide an adequate level of oversight with respect to the degree of risk being taken by management to achieve short-term performance goals.

We believe our compensation program has been instrumental in our achievement of stated objectives. Over the five-year period ended December 31, 2008, our annual distribution per common unit has grown at a compound annual rate of 9.7% and the total return realized by our unitholders for that period averaged approximately 8.2%. During this period, we have enjoyed a very high rate of retention among executive officers.

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) through December 31, 2008, Messrs. Armstrong and Pefanis have each received one salary adjustment, Mr. Kramer received two salary adjustments, Mr. Duckett has received small salary adjustments in line with other Canadian personnel, Mr. vonBerg has received no salary adjustment and Mr. Swanson received three salary adjustments.

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 Mr. Duckett, 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 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 is recommended to or by Mr. Pefanis and reviewed, modified and approved by Mr. Armstrong, as appropriate. Messrs. Pefanis and 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 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.

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, 2008 pursuant to individual restricted units agreements between Plains AAP, L.P. and certain members of management. As of December 31, 2008 our Named Executive Officers held 111,000 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 2008

At the beginning of 2008, we established four public goals with paraphrased versions of two of these goals overlapping with two of our five internal goals. As a result, we entered 2008 with seven distinct goals for the year.

The four public goals for the year were to:

1. Deliver baseline operating and financial performance in line with guidance;

2. Successfully execute our 2008 capital program and set the stage for 7% to 10% adjusted EBITDA growth in 2009;

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

4. Increase year-over-year distributions in 2008 by $0.20 - $0.25 per unit. In connection with closing the Rainbow acquisition in May 2008, the year-over-year distribution growth target range was increased to $0.25 - $0.30 per unit (equivalent to a November 2008 annualized distribution of $3.61 to $3.66 per unit).

Our three internal qualitative goals included (i) the continued expansion of our asset integrity management program with respect to assets not covered by regulatory mandate, (ii) maintaining and improving organizational communication, and (iii) preparing the organization for future growth.

In general, we met or exceeded these seven goals, but performance relative to execution of our 2008 capital program included one notable exception (discussed in paragraph 2. below).

With respect to our four public goals:

1. Excluding the unforecasted contribution from acquisitions completed during the year, our adjusted EBITDA was in line with the midpoint of the original guidance for 2008 and performance from acquisitions completed during the year was in line with updated guidance;

2. We began the year with a $330 million capital program that was expanded during the year to $470 million. The vast majority of these projects were timely completed and in line with cost forecast, but one pipeline construction project encountered significant difficulties resulting in a delay and a measurable cost overrun. Financial and operating guidance furnished for 2009 is in line with targeted growth objectives;

3. We completed two strategic and complementary acquisitions totaling approximately $735 million. Excluding the Pacific acquisition completed in 2006, our three year average acquisition expenditures total approximately $487 million per year; and

4. We paid approximately $3.50 per unit in distributions during 2008, a $0.22 per unit increase over the $3.28 paid per unit in 2007. Our November 2008 annualized distribution rate was $3.57 per unit, which represented a 6.3% increase over the November 2007 annualized rate of $3.36 per unit. This increase is within the targeted 5% to 8% range established at the beginning of 2008, but is below the increased range targeted in connection with the Rainbow acquisition. The November distribution reflects management's decision to balance the near-term benefits of distribution growth with the long-term benefits of retaining excess cash flow during challenging financial times for capital formation.

During 2008, we continued to expand, implement and develop our integrity management. Many actions were taken in 2008 to improve communication throughout the organization and special efforts were made during the year to timely address headline issues regarding the turmoil in the financial markets, events affecting certain of our competitors and our relative positioning. We also continued to define and develop succession plans, added important members to the senior management team and successfully managed through several planned and unplanned changes at the senior management level.

For 2008, the elements of compensation were applied as follows:

Salary. No salary adjustments for Named Executive Officers were recommended or made in 2008. See "—Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table."

Cash Bonuses. Based on the CEO's annual performance review and the individual performance of each of our 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 seven goals established for 2008; the absence of shortfalls relative to expectations, save and except for the delay and cost overrun on one pipeline construction project; 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. They also reflect performance relative to the three internal goals discussed above. 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 47% in annual bonus and 53% in quarterly bonus. The bonus amounts for Named Executive Officers in 2008 are generally lower than those earned in either 2007 or 2006, reflecting the assessment that although the Partnership achieved its goals in all three years, the level of over-performance in 2008 was less than that generated in the prior two years.

Long-Term Incentive Awards. There were no grants of long-term incentive awards to Named Executive Officers in 2008. See "—Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table."

Other Compensation Related Matters

Equity Ownership in PAA. As of December 31, 2008, our Named Executive Officers collectively owned substantial equity in the Partnership. Although we encourage our Named Executive Officers to acquire and 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, 2008, our Named Executive Officers beneficially owned, in the aggregate, approximately 756,072 of our common units (excluding any unvested equity awards), an approximately 2.8% indirect ownership interest in our general partner and IDRs, and 111,000 Class B units of Plains AAP, L.P. Based on the market price of our common units at December 31, 2008 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 2008.

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. The Class B restricted units agreements generally call for vesting upon a change in control of any units that have already been earned, plus the next increment of units that could be earned at the next distribution threshold. Any remaining Class B restricted units would be forfeited (unless waived at the discretion of the general partner or acquirer as the case may be). See "—Employment Contracts" and "—Potential Payments upon Termination or Change-in-Control."

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Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer, our current Chief Financial Officer, the three other most highly compensated executive officers in 2008 and our former Chief Financial Officer (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	2008	375,000	2,900,000	3,298,793	14,775	6,588,568
Chairman and CEO	2007	375,000	3,400,000	5,660,135	14,430	9,449,565
	2006	375,000	3,750,000	5,184,222	15,930	9,325,152
Harry N. Pefanis	2008	300,000	2,800,000	2,447,340	14,775	5,562,115
President and Chief Operating	2007	300,000	3,200,000	3,854,810	14,430	7,369,240
Officer	2006	300,000	3,400,000	3,456,148	15,930	7,172,078
Phillip D. Kramer	2008	250,000	700,000	135,152	14,775	1,099,927
Executive Vice President*	2007	250,000	850,000	1,651,155	14,430	2,765,585
	2006	250,000	1,000,000	1,876,043	15,930	3,141,973
W. David Duckett(3)	2008	268,095	2,915,424(3)	1,787,827	88,831	5,060,177
President—PMC (Nova Scotia)	2007	266,960	3,028,488(3)	2,228,516	93,501	5,617,465
Company	2006	251,302	2,063,109(3)	2,203,918	63,349	4,581,678
John P. vonBerg	2008	200,000	2,740,000(4)	1,258,096	14,580	4,212,676
Senior Vice President—	2007	200,000	2,765,000(4)	1,780,055	14,244	4,759,299
Commercial Activities	2006	200,000	2,934,700(4)	1,575,530	15,744	4,725,974
Al Swanson	2008	180,000	700,000	997,345	14,502	1,891,847
Senior Vice President and						
Chief Financial Officer*						

* Effective November 15, 2008, Mr. Swanson was promoted to Senior Vice President and Chief Financial Officer. In connection with relinquishing his role as Chief Financial Officer, Mr. Kramer assumed responsibility for certain of our commercial activities.

(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 years 2007 and 2008. 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. 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 Swanson includes $13,800 in such contributions for 2008. 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 2008, employer contributions to the PMC (Nova Scotia) Company savings plan of $34,852, group term life insurance premiums of $17,345, automobile lease payments of $31,478 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.

(4) Includes quarterly bonuses aggregating $1,440,000, $1,765,000 and $1,834,700 and annual bonuses of $1,300,000, $1,000,000 and $1,100,000 in 2008, 2007 and 2006, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Grants of Plan-Based Awards Table

There were no grants of plan-based awards to our Named Executive Officers during the fiscal year ended December 31, 2008.

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

A discussion of 2008 salaries and bonuses is included in "—Compensation Discussion and Analysis." The following is a discussion of other material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and under "—Grants of Plan-Based Awards Table" above.

Salary—As discussed in this Item 11, we do not make systematic annual adjustments to the salaries of our Named Executive Officers. In that regard, no salary adjustments were made for any of our Named Executive Officers in 2008. In February 2009, the annual salary of each of Mr. vonBerg and Mr. Swanson was increased to $250,000.

Grants of Plan-Based Awards—As noted above, there were no grants of plan-based awards to our Named Executive Officers during the fiscal year ended December 31, 2008. In February 2009, Mr. Swanson was awarded 35,000 phantom units under our LTIP. Also in February 2009, Mr. Kramer was awarded 7,000 Class B restricted units of Plains AAP, L.P.

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.

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

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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 Messrs. Armstrong's and Pefanis' employment agreements related to termination, change of control and related payment obligations.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2008 with respect to our Named Executive Officers:

	Option Awards					Unit Awards			
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)	—	—	$ 6.13	6/07/2011	210,000(3)	7,284,900	—	—
	—	—	—	—	—	60,000(4)	2,081,400	120,000(4)	4,162,800
	—	—	—	—	—	10,000(5)	2,772,400	30,000(5)	5,985,600
Harry N. Pefanis	27,500(2)	—	—	$ 6.13	6/07/2011	140,000(3)	4,856,600	—	—
	—	—	—	—	—	40,000(4)	1,387,600	80,000(4)	2,775,200
	—	—	—	—	—	7,500(5)	2,079,300	22,500(5)	4,489,200
Phillip D. Kramer	22,500(2)	—	—	$ 6.13	6/07/2011	60,000(6)	2,081,400	—	—
	—	—	—	—	—	20,000(4)	693,800	40,000(4)	1,387,600
W. David Duckett	—	—	—	—	—	78,350(6)	2,717,962	—	—
	—	—	—	—	—	25,000(4)	867,250	50,000(4)	1,734,500
	—	—	—	—	—	—	—	17,000(5)	3,722,150
John P. vonBerg	—	—	—	—	—	57,350(6)	1,989,472	—	—
	—	—	—	—	—	18,000(4)	624,420	36,000(4)	1,248,840
	—	—	—	—	—	3,500(5)	970,340	10,500(5)	2,094,960
Al Swanson	—	—	—	—	—	34,000(6)	1,179,460	—	—
	—	—	—	—	—	11,000(4)	381,590	22,000(4)	763,180
	—	—	—	—	—	—	—	10,000(5)	2,189,500

(1) Market value of phantom units reported in these columns is calculated by multiplying the closing market price ($34.69) of our common units at December 31, 2008 (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 No. 123 (revised 2004), "Share-Based Payment" ("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. These options vested in 2002 and 2004.

(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 May 2011 distribution date; 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. The first 25% of DERs associated with these units is currently payable. The remaining 75% become payable in 25% increments upon achieving quarterly distribution levels of $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. As of December 31, 2008, 25% of the Class B units held by Messrs. Armstrong, Pefanis and vonBerg had been earned. Twenty-five percent of the Class B units held by Messrs. Duckett and Swanson were earned as of February 10, 2009. None of the Class B units have vested. For additional information regarding the Class B Units, please read Item 13. "Certain Relationships and Related Transactions, and Director Independence—Our General Partner—Class B Units of Plains AAP, L.P."

(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.

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	—	—	—	—
Harry N. Pefanis	—	—	—	—
Phillip D. Kramer	—	—	—	—
W. David Duckett	—	—	16,650	775,557
John P. vonBerg	—	—	16,650	775,557
Al Swanson	—	—	5,000	232,900

(1) Represents the gross number and value of phantom units that vested during the year ended December 31, 2008. 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 2008. Consistent with the terms of our 2005 Long-Term Incentive Plan, the value realized upon vesting is computed by multiplying the closing market price ($46.58) of our common units on May 14, 2008 (the date preceding the vesting date) by the number of units that vested.

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, 2008.

	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	11,447,700(3)	11,447,700(3)	13,529,100(4)	13,529,100(4)	13,529,100(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	1,572,936(7)
Class B Units	N/A	N/A	N/A	N/A	5,382,400(8)
Total	19,697,700	19,733,910	21,815,310	21,815,310	32,895,646
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	7,631,800(3)	7,631,800(3)	9,019,400(4)	9,019,400(4)	9,019,400(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	1,510,266(7)
Class B Units	N/A	N/A	N/A	N/A	4,036,800(8)
Total	15,031,800	15,068,010	16,455,610	16,455,610	25,702,676
Phillip D. Kramer(9)					
Equity Compensation	3,469,000(3)	3,469,000(3)	2,775,200(4)	N/A	4,162,800(5)
Total	3,469,000	3,469,000	2,775,200	N/A	4,162,800
W. David Duckett(9)					
Equity Compensation	4,452,462(3)	4,452,462(3)	3,585,212(4)	N/A	5,319,712(5)
Class B Units	N/A	N/A	N/A	N/A	1,178,270(8)
Total	4,452,462	4,452,462	3,585,212	N/A	6,497,982
John P. vonBerg(9)					
Equity Compensation	3,238,312(3)	3,238,312(3)	2,613,892(4)	N/A	3,862,732(5)
Class B Units	N/A	N/A	N/A	N/A	1,883,840(8)
Total	3,238,312	3,238,312	2,613,892	N/A	5,746,572
Al Swanson(9)					
Equity Compensation	1,942,640(3)	1,942,640(3)	1,561,050(4)	N/A	2,324,230(5)
Class B Units	N/A	N/A	N/A	N/A	693,100(8)
Total	1,942,640	1,942,640	1,561,050	N/A	3,017,330

(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 in Section 409A of the Code) 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, 2008, 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 "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, 2008, 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 Vulcan Energy 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 owners of the membership interests of Plains All American GP LLC on June 30, 2001 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 greater than 50%. 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 phantom unit grants to our Named Executive Officers between 2005 and 2007 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 nonforfeitable, and (i) 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 vest on the next following distribution date and (ii) the remaining unvested outstanding phantom units will vest on the distribution date on which the vesting criteria is met. 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, 2008. As a result, all phantom units and the associated DERs of our Named Executive Officers would have become nonforfeitable effective as of December 31, 2008, and vested on February 13, 2009 to the extent the vesting criteria had been satisfied (other than the passage of time) or, if the vesting criteria had not been satisfied, 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, 2008, and is based on the market value on December 31, 2008 ($34.69 per unit) without discount for service period. If the performance thresholds were not deemed probable of occurrence as of December 31, 2008, the units are assumed to expire unvested in May 2014. At December 31, 2008, an annualized distribution level of $3.75 was deemed probable of occurrence. All outstanding 2005 and 2006 grants and two-thirds of the 2007 grants were assumed to eventually vest as a result.

(4) Pursuant to the phantom unit grants to our Named Executive Officers between 2005 and 2007, 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, disability (as defined in Footnote 3 above) or retirement, all of the phantom units and associated DERs (regardless of vesting) then outstanding under such 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, 2008. As a result, all of the outstanding 2005 and 2006 phantom unit grants and one-third of the 2007 phantom unit grants held by our Named Executive Officers would be deemed nonforfeitable and would vest on the February 2009 distribution date. The remaining two-thirds of the outstanding 2007 phantom unit grants would be forfeited. The dollar value given is based on the market value on December 31, 2008 of $34.69 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 letters evidencing the phantom unit grants to our Named Executive Officers between 2005 and 2007 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 nonforfeitable, and such phantom units will vest in full (i.e., the phantom units will become payable in the form of one common unit per phantom unit) upon the next following distribution date. Assuming the change in status occurred on December 31, 2008, all outstanding phantom units and the associated DERs would have become nonforfeitable as of December 31, 2008, and such phantom units would vest on the February 2009 distribution date.

The phrase "change in status" means, with respect to a Named Executive Officer, the occurrence, during the period beginning two and a half months prior to and ending one year following a change of control (as defined below), of any of the following: (A) the termination of employment by Plains All American GP LLC other than a termination for cause (as defined below), or (B) the termination of employment by the Named Executive Officer due to the occurrence, without the Named Executive Officer's written consent, of (i) any material diminution in the Named Executive Officer's authority, duties or responsibilities, (ii) any material reduction in the Named Executive Officer's base salary or (iii) any other action or inaction that would constitute a material breach of the agreement by Plains All American GP LLC.

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 as of the grant date 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 Energy in August 2005 (such exception not applying to the November 2005 grants to Messrs. vonBerg and Duckett or the February 2006 grant to Mr. Swanson). 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 Plains All American 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, 2008.

(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, 2008.

(8) Pursuant to the Class B Restricted Units Agreements, upon the occurrence of a Change in Control, any earned Class B units become vested units and, to the extent any Class B units remain unearned, an incremental 25% of the number of Class B units originally granted becomes vested. As of December 31, 2008, 25% of the Class B units held by Messrs. Armstrong, Pefanis and vonBerg had been earned. On February 10, 2009, 25% of the Class B units held by Messrs. Duckett and Swanson became earned. Assuming a Change in Control on December 31, 2008, 50% of the Class B units held by Messrs. Armstrong, Pefanis and vonBerg would become vested, and 25% of the Class B units held by Messrs. Duckett and Swanson would become vested. The value of such Class B 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 as of August 29, 2007 (the "Grant Date") 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" 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, vonBerg or Swanson 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.

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. Mr. Duckett has agreed to maintain confidentiality following termination of his employment for a period of two years with respect to customer lists. He has also agreed not to compete in a specified geographic area for a period of two years after termination of his employment. Mr. vonBerg has agreed to maintain confidentiality and not to solicit customers for a period of one year following termination of his employment.

Compensation of Directors

The following table sets forth a summary of the compensation paid to Plains All American GP LLC's non-employee directors in 2008:

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	30,931	—	—	—	—	77,931
W. Lance Conn(2)	—(2)	—(2)	—	—	—	—	—(2)
Everardo Goyanes	75,000	48,278	—	—	—	—	123,278
Gary R. Petersen(2)	45,000	30,931	—	—	—	—	75,931
Robert V. Sinnott	45,500	16,970	—	—	—	—	62,470
Arthur L. Smith	62,000	48,278	—	—	—	—	110,278
J. Taft Symonds	60,000	48,278	—	—	—	—	108,278

(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 vesting of these LTIP awards in August 2008 (other than the incremental audit committee awards), a cash payment was made to Vulcan Capital and an affiliate of EnCap as directed by Messrs. Capobianco and Petersen, respectively. Such cash payment was based on the unit value of Mr. Sinnott's award 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, while serving in such capacity, will continue to have outstanding an award of 10,000 units and Mr. Sinnott, while serving as a director, will continue to 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 2008. See Note 10 to our Consolidated Financial Statements for a discussion of the assumptions made in determining these amounts.

(2) Mr. Capobianco served as a director until November 14, 2008, at which time Mr. Conn was designated by an affiliate of Vulcan Capital to replace him. During his term, Mr. Capobianco assigned to Vulcan Capital any compensation attributable to his service as director. Mr. Conn has also assigned 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. During 2008, Messrs. Capobianco, Goyanes and Smith served as chairmen of the compensation, audit and governance committees, respectively.

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). Upon any vesting (other than the incremental audit committee awards), a cash payment is made to Vulcan Capital as directed by the Vulcan designee and to an affiliate of EnCap as directed by Mr. Petersen. Such cash payment is based on the unit value of Mr. Sinnott's award on the previous year's vesting date.

All LTIP awards held by a director vest in full upon the next following 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 (other than expenses related to the Class B units of Plains AAP, L.P.) 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.

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, 2009.

Name of Beneficial Owner	Common Units	Percentage of Common Units
Paul G. Allen	14,386,074(1)	11.7%(2)
Vulcan Energy Corporation	12,390,120(3)	10.1%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	8,328,737(4)	6.8%
Greg L. Armstrong	292,607(5)(6)(7)	(8)
Harry N. Pefanis	184,697(6)(7)	(8)
Phillip D. Kramer	115,190(6)(7)	(8)
Dave Duckett	147,997(6)	(8)
John P. vonBerg	10,581(6)	(8)
Al Swanson	5,000(6)	(8)
W. Lance Conn	—(9)	(8)
Everardo Goyanes	20,200	(8)
Gary R. Petersen	5,200(10)	(8)
Robert V. Sinnott	17,750(11)	(8)
Arthur L. Smith	18,350	(8)
J. Taft Symonds	27,500	(8)
All directors and executive officers as a group (15 persons)	885,161(7)(12)	(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 12.5% 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 8,102,572 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 226,165 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 138,103 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 our Long-Term Incentive Plans, 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; and all directors and executive officers as a group: 87,500.

(8) Less than one percent.

(9) The GP LLC Agreement specifies that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Conn has been designated as one of our directors by Vulcan Energy Corporation, of which he is Chairman of the Board. Pursuant to certain agreements, Mr. Conn has the right to receive a performance-based fee based on the performance of the holdings of Vulcan Energy and Vulcan LLC, including the common units held by these entities. Mr. Conn 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 greater than 50% ownership in the general partner, Vulcan Energy Corporation controls the vacant "at-large" seat and the "at-large" seat occupied by Mr. Petersen.

(10) Mr. Petersen is Senior Managing Director of EnCap Investments L.P., which is an affiliate of E-Holdings III, L.P. 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 therein, if any.

(11) 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, beyond his pecuniary interest therein, if any. 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.

(12) As of February 20, 2009, 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, 2009.

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 of Owner and Address (in the case of Owners of more than 5%)	Percentage Ownership of Plains AAP, L.P.(1)
Paul G. Allen(2) 505 Fifth Avenue S, Suite 900 Seattle, WA 98104	50.1%
Vulcan Energy Corporation(3) c/o Plains All American GP LLC 333 Clay Street, Suite 1600 Houston, TX 77002	50.1%
KAFU Holdings, L.P.(4) 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	17.9%
Oxy Holding Company (Pipeline), Inc.(5) 10889 Wilshire Boulevard Los Angeles, CA 90024	10.0%
E-Holdings III, L.P.(6) 1100 Louisiana, Suite 3150 Houston, TX 77002	7.1%
E-Holdings V, L.P.(6) 1100 Louisiana, Suite 3150 Houston, TX 77002	1.7%
PAA Management, L.P.(7)	4.6%
Wachovia Investors, Inc.	3.1%
Various Individual Investors	0.8%
Mark E. Strome	2.6%
Strome MLP Fund, L.P.	0.9%
Lynx Holdings I, LLC	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.

(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 50.1% 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 (as amended, 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. Conn disclaims any deemed beneficial ownership of the interests held by Vulcan Energy Corporation and its affiliates beyond his pecuniary interest therein, if any. In August 2005, Vulcan Energy Corporation entered into a voting agreement pursuant to which it agreed to restrict certain of its voting rights to help preserve a balanced board. See Item 10. "Directors and Executive Officers of Our General Partner and Corporate Governance—Partnership Management and Governance" for more information regarding this agreement.

(4) Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. beyond his pecuniary interest therein, if any. 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) Oxy has the right to designate an individual to attend Board meetings in an observer capacity. Under certain circumstances involving changes in upper-level management, Oxy will have the right to designate a director to serve on the Board and the authorized number of Board members will be expanded to a total of nine.

(6) 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 therein, if any.

(7) 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%), Duckett (approximately 4%), vonBerg (approximately 4%) and Swanson (approximately 5%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Executive officers as a group own approximately 66% 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.

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Equity Compensation Plan Information

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2008. 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	715,400(1)	N/A(2)	201,390(1)(3)
2005 Long Term Incentive Plan	1,655,080(4)	N/A(2)	1,034,625(3)
Equity compensation plans not approved by unitholders:			
1998 Long Term Incentive Plan	—(1)(5)	N/A(2)	—(6)
General Partner's Performance Option Plan	—(7)	$ 6.13(8)	—(7)
PPX Successor LTIP	45,000(9)	N/A(2)	954,809(9)

(1) As originally instituted by our former general partner prior to our initial public offering, the 1998 LTIP contemplated the issuance of up to 975,000 common units to satisfy awards of phantom units. Upon vesting, these awards could be satisfied either by (i) primary issuance of units by us or (ii) cash settlement or purchase of units by our general partner with the cost reimbursed by us. In 2000, the 1998 LTIP was amended, as provided in the plan, without unitholder approval to increase the maximum awards to 1,425,000 phantom units; however, we can issue no more than 975,000 new units to satisfy the awards. Any additional units must be purchased by our general partner in the open market or in private transactions and be reimbursed by us. As of December 31, 2008, 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 369,532 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 131,250 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, 2008, the strike price for all outstanding options under the general partner's Performance Option Plan was approximately $6.13 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 (other than expenses related to the Class B units of Plains AAP, L.P.). Total costs reimbursed by us to our general partner for the year ended December 31, 2008 were approximately $289 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 and Rainbow acquisitions, our general partner agreed to a temporary reduction in the amount of incentive distributions otherwise payable to it. The aggregate reduction will be $75 million over a five-year period. Following our distribution in February 2009, the remaining incentive distribution reductions related to Pacific and Rainbow totaled approximately $31 million.

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	$ 221,400	$ 4,518	$ 225,918	2%
$1.98	$ 243,540	$ 8,425	$ 251,965	3%
$2.70	$ 332,100	$ 37,945	$ 370,045	10%
$3.60	$ 442,800	$ 148,645	$ 591,445	25%
$3.70	$ 455,100	$ 160,945	$ 616,045	26%
$3.80	$ 467,400	$ 173,245	$ 640,645	27%
$3.90	$ 479,700	$ 185,545	$ 665,245	28%
$4.00	$ 492,000	$ 197,845	$ 689,845	29%

(1) In thousands.

(2) Assumes 123,000,000 units outstanding. The actual number of units outstanding as of December 31, 2008 was 122,911,645. 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 and 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, 2008, grants of approximately 715,400, 1,655,080 and 450,200 unvested phantom units were outstanding under the 1998 LTIP, 2005 LTIP and PPX Successor LTIP, respectively, and approximately 201,390, 1,034,625 and 954,809 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, 2008, 131,250 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, 2008, the exercise price was approximately $6.13 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 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, 2008 was approximately $13 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, 2008, 154,000 Class B units were issued and outstanding.

The outstanding Class B units are subject to restrictions on transfer and 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. As of February 10, 2009, 25% of the outstanding Class B units had been earned.

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, 2008, Vulcan Energy and its affiliates owned approximately 50.1% of our general partner interest, as well as approximately 10% 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, Vulcan Energy's ownership interest increased from 44% to over 50%. 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. Beginning in October 2008, the Services Agreement automatically renews 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 Energy 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 Energy 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. From August 2005 to May 2007, Calumet Florida L.L.C. ("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.

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, an affiliate of Vulcan Capital and an affiliate of EnCap each have a representative on our board of directors.

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., owned 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 2005. We own 50% of PAA/Vulcan and the remaining 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan LLC, an investment arm of Paul G. Allen. Mr. Conn has 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 (now known as PAA Natural Gas Storage, LLC), an indirect subsidiary of Sempra Energy, for approximately $250 million. We and Vulcan Gas Storage 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.

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"). We have 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 have executed hedges on the NYMEX for the relevant delivery periods. At the time of delivery, the base gas will be sold to PAA/Vulcan at the average price that we pay for the base gas (including hedge gains or losses) and we will not recognize any gain or loss. 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 and other agreements. 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 2008 and 2007, we made additional contributions of $37 million and $9 million, respectively, to PAA/Vulcan. During 2008, we received distributions of approximately $7 million from PAA/Vulcan; no such distributions were received during 2007. Vulcan Gas Storage made the same net contribution as we did during 2008 and 2007. Such contributions and distributions did not result in an increase or decrease to our ownership interest. In connection with the construction financing for development of the Pine Prairie storage facility, we and Vulcan Gas Storage have committed to make future aggregate capital contributions up to a maximum of $17.5 million each.

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). 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 2008 and 2007, we purchased approximately $3.6 million and $1.7 million, respectively, 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.

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 by the Partnership 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***

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

	Year Ended December 31,	
	2008	2007
Audit fees(1)	$ 2.6	$ 2.0
Audit-related fees(2)	0.2	0.1
Tax fees(3)	0.9	1.3
All other fees(4)	0.5	0.2
Total	$ 4.2	$ 3.6

(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.

Pre-Approval Policy

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. All services provided by our independent auditor during the years ended December 31, 2008 and 2007 were approved in advance by our audit committee.

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	—	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).
3.4	—	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).
3.5	—	Amendment No. 4 effective as of January 1, 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 April 15, 2008).
3.6	—	Amendment No. 5 dated May 28, 2008 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 May 30, 2008).
3.7	—	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).
3.8	—	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).
3.9	—	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.10	—	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed August 7, 2008).

3.11	—	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	—	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
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, 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, 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 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 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 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.9	—	Eighth Supplemental Indenture dated August 25, 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 August 25, 2006).
4.10	—	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 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 October 30, 2006 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 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	—	Twelfth Supplemental Indenture dated January 1, 2008 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 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.14	—	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 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 April 23, 2008).
4.15	—	Fourteenth Supplemental Indenture dated July 1, 2008 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 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.16	—	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the $7^{1}/8$% 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).

4.17	—	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P.'s Current Report on Form 8-K filed March 9, 2005).
4.18	—	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.19	—	Third Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a 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).
4.20	—	Fourth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.23 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.21†	—	Fifth Supplemental Indenture dated December 17, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee.
4.22	—	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a 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).
4.23	—	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a 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).
4.24	—	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).

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	—	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).
10.3	—	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).
10.4	—	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).
10.5	—	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).
10.6	—	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).
10.7**	—	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).
10.8**	—	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).
10.9**	—	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).

10.10**	—	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).
10.11**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.12**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13	—	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).
10.14	—	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).
10.15	—	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).
10.16	—	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).
10.17	—	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).
10.18**	—	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).
10.19**	—	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).
10.20**	—	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).
10.21**†	—	Directors' Compensation Summary.
10.22	—	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).

10.23**	—	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).
10.24**	—	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).
10.25**	—	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).
10.26**	—	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).
10.27**	—	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).
10.28**	—	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).
10.29	—	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).
10.30	—	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).
10.31	—	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).
10.32**	—	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).
10.33**	—	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).
10.34	—	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).
10.35	—	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).
10.36**	—	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).
10.37**	—	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).

10.38	—	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).
10.39**	—	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).
10.40**	—	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).
10.41**	—	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).
10.42	—	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).
10.43**	—	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).
10.44**	—	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).
10.45	—	Second Restated Credit Agreement dated as of November 6, 2008 by among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party there to (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 7, 2008).
10.46	—	Restated Guaranty Agreement dated November 6, 2008 by Plains All American Pipeline, L.P. 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 7, 2008).
10.47	—	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 on Form 8-K filed January 4, 2008).
10.48	—	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 (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2007).
10.49**†	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong.
10.50**†	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis.

10.51**†	—	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008.
10.52**†	—	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008.
10.53**†	—	Form of Amendment to LTIP grant letters (executive officers).
10.54**†	—	Form of Amendment to LTIP grant letters (directors).
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

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 26, 2009

By: /s/ AL SWANSON

Al Swanson,
Senior Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)

February 26, 2009

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 26, 2009
/s/ HARRY N. PEFANIS Harry N. Pefanis	President and Chief Operating Officer of Plains All American GP LLC	February 26, 2009
/s/ AL SWANSON Al Swanson	Senior Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 26, 2009
/s/ TINA L. VAL Tina L. Val	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 26, 2009
/s/ W. LANCE CONN W. Lance Conn	Director of Plains All American GP LLC	February 26, 2009
/s/ EVERARDO GOYANES Everardo Goyanes	Director of Plains All American GP LLC	February 26, 2009
/s/ GARY R. PETERSEN Gary R. Petersen	Director of Plains All American GP LLC	February 26, 2009
/s/ ROBERT V. SINNOTT Robert V. Sinnott	Director of Plains All American GP LLC	February 26, 2009
/s/ ARTHUR L. SMITH Arthur L. Smith	Director of Plains All American GP LLC	February 26, 2009
/s/ J. TAFT SYMONDS J. Taft Symonds	Director of Plains All American GP LLC	February 26, 2009

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" 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, 2008.

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2008 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/ AL SWANSON

Al Swanson
Senior Vice President and Chief Financial Officer of
Plains All American GP LLC
(Principal Financial Officer)

February 26, 2009

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 related 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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, 2008, 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.

Houston, Texas
February 26, 2009

PricewaterhouseCoopers LLP

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(in millions, except unit amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 11	$ 24
Trade accounts receivable and other receivables, net	1,525	2,561
Inventory	801	972
Other current assets	259	116
Total current assets	2,596	3,673
PROPERTY AND EQUIPMENT	5,727	4,938
Accumulated depreciation	(668)	(519)
	5,059	4,419
OTHER ASSETS		
Pipeline linefill in owned assets	425	284
Long-term inventory	139	74
Investment in unconsolidated entities	257	215
Goodwill	1,210	1,072
Other, net	346	169
Total assets	$ 10,032	$ 9,906
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 1,507	$ 2,577
Short-term debt	1,027	960
Other current liabilities	426	192
Total current liabilities	2,960	3,729
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	40	1
Senior notes, net of unamortized net discount of $6 and $2, respectively	3,219	2,623
Other long-term liabilities and deferred credits	261	129
Total long-term liabilities	3,520	2,753
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS' CAPITAL		
Common unitholders (122,911,645 and 115,981,676 units outstanding, respectively)	3,469	3,343
General partner	83	81
Total partners' capital	3,552	3,424
Total liabilities and partners' capital	$ 10,032	$ 9,906

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2008	2007	2006
	(in millions, except per unit data)		
REVENUES			
Crude oil, refined products and LPG sales and related revenues (includes buy/sell transactions of $4,762 for the 2006 period)	$ 29,348	$ 19,834	$ 22,060
Pipeline tariff activities, trucking and related revenues	556	439	344
Storage, terminalling, processing and related revenues	157	121	41
Total revenues	30,061	20,394	22,445
COSTS AND EXPENSES			
Crude oil, refined products and LPG purchases and related costs (includes buy/sell transactions of $4,795 for the 2006 period)	28,479	19,001	21,474
Field operating costs	617	531	382
General and administrative expenses	160	164	134
Depreciation and amortization	211	180	100
Total costs and expenses	29,467	19,876	22,090
OPERATING INCOME	594	518	355
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	14	15	8
Interest expense (net of capitalized interest of $17, $14 and $6, respectively)	(196)	(162)	(86)
Interest income and other income (expense), net	33	10	2
Income before tax	445	381	279
Current income tax expense	(9)	(3)	—
Deferred income tax benefit (expense)	1	(13)	—
Income before cumulative effect of change in accounting principle	437	365	279
Cumulative effect of change in accounting principle	—	—	6
NET INCOME	$ 437	$ 365	$ 285
NET INCOME—LIMITED PARTNERS	$ 325	$ 286	$ 247
NET INCOME—GENERAL PARTNER	$ 112	$ 79	$ 38
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 2.70	$ 2.54	$ 2.84
Cumulative effect of change in accounting principle	—	—	0.07
Net income	$ 2.70	$ 2.54	$ 2.91
DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 2.67	$ 2.52	$ 2.81
Cumulative effect of change in accounting principle	—	—	0.07
Net income	$ 2.67	$ 2.52	$ 2.88
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	120	113	81
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	121	114	82

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 437	$ 365	$ 285
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	211	180	100
Cumulative effect of change in accounting principle	—	—	(6)
(Gains)/losses from derivative activities	(141)	24	4
Inventory valuation adjustments	168	1	6
Gain on sale of linefill	(3)	(12)	—
Gain on sale of investment assets	(12)	(4)	—
Equity compensation expense	24	49	43
Deferred income tax (benefit) expense	(1)	13	—
Non-cash amortization of terminated interest rate and foreign currency hedging instruments	—	1	2
Loss on foreign currency revaluation	22	—	4
Equity earnings in unconsolidated entities, net of distributions	(4)	(14)	(7)
Net cash received/(paid) for terminated interest rate and foreign currency hedging instruments	15	—	(2)
Other	2	—	—
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	948	(743)	(731)
Inventory	(120)	340	(325)
Accounts payable and other current liabilities	(689)	596	351
Net cash provided by (used in) operating activities	857	796	(276)
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions (Note 3)	(709)	(127)	(1,264)
Additions to property, equipment and other	(589)	(548)	(341)
Investment in unconsolidated entities	(37)	(9)	(46)
Net cash paid for linefill in assets owned	(55)	(19)	(4)
Proceeds from sales of assets	51	40	4
Net cash used in investing activities	(1,339)	(663)	(1,651)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on revolving credit facilities	286	305	(296)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	(196)	(359)	616
Proceeds from the issuance of senior notes	597	—	1,243
Net proceeds from the issuance of common units (Note 5)	315	383	643
Distributions paid to common unitholders (Note 5)	(418)	(370)	(225)
Distributions paid to general partner (Note 5)	(114)	(81)	(38)
Other financing activities	(6)	(2)	(16)
Net cash provided by (used in) financing activities	464	(124)	1,927
Effect of translation adjustment on cash	5	4	1
Net increase (decrease) in cash and cash equivalents	(13)	13	1
Cash and cash equivalents, beginning of period	24	11	10
Cash and cash equivalents, end of period	$ 11	$ 24	$ 11
Cash paid for interest, net of amounts capitalized	$ 206	$ 186	$ 122
Cash paid for income taxes	$ 15	$ 3	$ —

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL

(in millions)

	Common Units		General Partner	Partners' Capital
	Units	Amount	Amount	Amount
Balance at December 31, 2005	**74**	**$1,294**	**$ 37**	**$ 1,331**
Net income	—	247	38	285
Distributions	—	(225)	(38)	(263)
Issuance of common units in connection with Pacific acquisition	22	1,002	22	1,024
Issuance of common units	13	609	12	621
Other comprehensive loss	—	(21)	—	(21)
Balance at December 31, 2006	**109**	**$2,906**	**$ 71**	**$ 2,977**
Net income	—	286	79	365
Distributions	—	(370)	(81)	(451)
Issuance of common units	6	375	8	383
Issuance of common units under Long Term Incentive Plans ("LTIP")	1	17	—	17
Class B Units of Plains AAP, L.P. (Note 10)	—	2	1	3
Other comprehensive income	—	127	3	130
Balance at December 31, 2007	**116**	**$3,343**	**$ 81**	**$ 3,424**
Net income	—	325	112	437
Distributions	—	(418)	(114)	(532)
Issuance of common units	7	309	6	315
Issuance of common units under LTIP	—	1	—	1
Class B Units of Plains AAP, L.P. (Note 10)	—	12	—	12
Other comprehensive loss	—	(103)	(2)	(105)
Balance at December 31, 2008	**123**	**$3,469**	**$ 83**	**$ 3,552**

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31, 2008	2007	2006
	(in millions)		
Net income	$ 437	$365	$285
Other comprehensive income/(loss)	(105)	130	(21)
Comprehensive income	$ 332	$495	$264

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

	Derivative Instruments	Translation Adjustments	Total
	(in millions)		
Balance at December 31, 2005	$ (16)	$ 87	$ 71
Reclassification adjustments	(144)	—	(144)
Changes in fair value of outstanding hedge positions	142	—	142
Currency translation adjustment	—	(17)	(17)
Deferred losses on settled hedges, net	(2)		(2)
2006 Activity	(4)	(17)	(21)
Balance at December 31, 2006	$ (20)	$ 70	$ 50
Reclassification adjustments	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
Reclassification adjustments	46	—	46
Changes in fair value of outstanding hedge positions	(131)	—	(131)
Deferred gains on settled hedges, net	242	—	242
Currency translation adjustment	—	(262)	(262)
2008 Activity	157	(262)	(105)
Balance at December 31, 2008	$ 161	$ (86)	$ 75

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 the context indicates otherwise.

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas-related petroleum products collectively as "LPG." Through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC ("PAA/Vulcan"), we 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 17 owners with interests ranging from approximately 50% to less than 1%.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2008 and 2007, 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, 2008, 2007 and 2006. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to the previous years to conform to the 2008 presentation. These reclassifications do not affect net income. The accompanying consolidated financial statements include Plains and all of its wholly owned subsidiaries. Investments in 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 Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock" ("APB 18"). 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 (revised 2004), "Share-Based Payment" ("SFAS 123(R)") was issued, which amended SFAS No. 123, "Accounting for Stock-Based Compensation," and established 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,

Note 1—Organization and Basis of Presentation (Continued)

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 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.

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." EITF 04-13 requires 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. EITF 04-13 includes 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 for 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. We make significant estimates with respect to: (i) accruals related to purchases and sales, (ii) mark-to-market gains and losses pursuant to SFAS No. 133, "Accounting For Derivative Instruments and Hedging Activities," as amended ("SFAS 133"), and SFAS No. 157, "Fair Value Measurements" ("SFAS 157"), (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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

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 and are subject to make up rights for take or pay arrangements. All pipeline tariff and fee revenues are based on actual volumes and rates. As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. In addition, we have certain agreements that require counterparties to ship a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume is shipped (pursuant to specifications outlined in the tariffs) or when the counterparty's ability to make up the minimum volume has expired.

Facilities Segment Revenues. Storage and terminalling revenues 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 carriers. Revenues from 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. All terminalling and storage revenues are based on actual volumes and rates. In addition, we have certain agreements that require counterparties to throughput a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume exits the terminal or when the counterparty's ability to make up the minimum volume has expired.

Marketing Segment Revenues. Revenues from sales of crude oil, LPG and refined products 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, LPG and refined products 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. See Note 1 for further discussion.

Purchases and Related Costs

Purchases and related costs include: (i) the cost of crude oil, LPG and refined products 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 costs are recognized when incurred except in the case of products purchased, which are recognized at the time title transfers to us.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

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

Certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Assets and liabilities of subsidiaries with a Canadian dollar functional currency 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.

Certain of our subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than the entities' respective functional currencies. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in the consolidated statements of operations within crude oil, refined products and LPG sales and related revenues. The revaluation of foreign currency transactions and monetary assets and liabilities resulted in a loss of approximately $31 million for the year ended December 31, 2008, a gain of less than $1 million for the year ended December 31, 2007 and a loss of approximately $4 million for the year ended December 31, 2006.

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 our credit risk is minimal. In accordance with our policy, outstanding checks are classified as accounts payable rather than negative cash. As of December 31, 2008 and 2007, accounts payable included approximately $44 million and $63 million, respectively, of outstanding checks that were reclassed from cash and cash equivalents.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG and refined products. These purchasers include refineries, producers, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. 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.

During 2008, the U.S. and world financial markets were extremely volatile and the global economies substantially weakened. In addition, during the first seven months of 2008, the values of crude oil and refined products reached historically high levels, but energy prices dropped precipitously

Note 2—Summary of Significant Accounting Policies (Continued)

during the remainder of the year to much lower levels. This volatility in the financial markets combined with the significant energy price volatility has caused liquidity issues impacting many companies, which in turn have increased the potential credit risks associated with certain counterparties with which we do business.

We have a rigorous credit review process and closely monitor these conditions in order to make a determination with respect to the amount, if any, 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, 2008 and 2007, we had received approximately $66 million and $57 million, respectively, of advance cash payments 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, 2008 and 2007, substantially all of our net accounts receivable classified as current assets were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $5 million and $1 million at December 31, 2008 and 2007, 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, LPG and refined products 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 within specific inventory pools.

At the end of each reporting period we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. During 2008, we recorded a non-cash charge of approximately $168 million related to the writedown of our crude oil and LPG inventory due to declines in oil prices during the third and fourth quarters of 2008. During 2007 and 2006, we recorded non-cash charges of approximately $1 million and $6 million, respectively, related to the writedown of such inventory. 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 2008 and 2007, we recorded gains of approximately $3 million and $12 million, respectively, on the sale of pipeline linefill for proceeds of approximately $23 million and $20 million, respectively. During 2006, both the gain and applicable proceeds for the sale of pipeline linefill were immaterial.

Minimum working inventory requirements in third-party assets and other working inventory in our assets that is needed for our commercial operations are included in Inventory (a current asset) in determining the average cost of operating inventory. At the end of each period, we reclassify the

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

inventory not expected to be liquidated within the succeeding twelve months out of inventory, at average cost, and into long-term inventory, which is reflected as a separate line item within other assets on the consolidated balance sheet.

Inventory and linefill consisted of the following (barrels in thousands and dollars in millions, except per barrel amounts):

	December 31, 2008			December 31, 2007		
	Barrels	Dollars	Dollars/ Barrel(1)	Barrels	Dollars	Dollars/ Barrel(1)
Inventory						
Crude oil	9,986	$ 421	$ 42.16	7,365	$ 592	$ 80.38
LPG	7,748	370	$ 47.75	6,480	363	$ 56.02
Refined products	103	5	$ 48.54	133	11	$ 82.71
Parts and supplies	N/A	5	N/A	N/A	6	N/A
Inventory subtotal	17,837	801		13,978	972	
Long-term inventory						
Crude oil	1,781	121	$ 67.94	986	64	$ 64.91
LPG	363	18	$ 49.59	175	10	$ 57.14
Long-term inventory subtotal	2,144	139		1,161	74	
Pipeline linefill in owned assets						
Crude oil	9,148	422	$ 46.13	7,734	282	$ 36.46
LPG	67	3	$ 44.78	43	2	$ 46.51
Pipeline linefill in owned assets subtotal	9,215	425		7,777	284	
Total	29,196	$1,365		22,916	$1,330	

(1) The prices listed represent a weighted average associated with various grades and qualities of crude oil, LPG and refined products and, accordingly, are not comparable metrics 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, 2008, 2007 and 2006, capitalized interest was $17 million, $14 million and $6 million, respectively. We also capitalize expenditures for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production, and/or functionality of our existing assets. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are charged to expense as incurred.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

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

	Estimated Useful Lives (Years)	December 31, 2008	2007
Crude oil pipelines and facilities	30 - 40	$ 3,934	$ 3,603
Crude oil and LPG storage and terminal facilities	30 - 40	944	599
Trucking equipment and other	5 - 40	300	233
Office property and equipment	3 - 5	75	64
Construction in progress	—	474	439
		5,727	4,938
Less accumulated depreciation		(668)	(519)
Property and equipment, net		$ 5,059	$ 4,419

Depreciation expense for the years ended December 31, 2008, 2007 and 2006 was $196 million, $160 million and $91 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 and 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. In turn, contributions will increase the carrying value of our investments and will be reflected on our cash flow statement within investing activities.

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 and facilities segments, 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 is 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 have estimated that the fair value of these obligations was approximately $5 million and $8 million at December 31, 2008 and 2007, respectively, and decreased primarily as a result of a change in estimates.

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. 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;

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

- 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.

During 2008, we recognized an impairment of approximately $5 million for the write down of a pipeline that was taken out of service. Impairments of approximately $1 million and less than $1 million were recognized during 2007 and 2006, respectively, and were predominantly related to assets that were taken out of service. 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) and on an interim basis if a triggering event occurs, such as an adverse change in business climate, to determine whether an impairment has occurred. In addition, there is a potential indicator of impairment if a company's market capitalization is less than its book equity. 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. SFAS 142 requires a two step approach to testing goodwill for impairment. In Step 1, we compare the fair value of the reporting unit with the respective book values, including goodwill, by using an earnings multiple approach. Multiples of earnings are estimated based on the average multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA") upon which our MLP peers have closed recent acquisitions and which management believes are comparable to our business. When the fair value is greater than book value, then the reporting unit's goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit's goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value.

At December 31, 2008, we compared our market capitalization to our book equity to determine if there was an indicator of impairment. Although our market capitalization exceeded the book value of our equity at December 31, 2008, we performed Step 1 of the goodwill impairment test due to the ongoing deterioration of the credit markets and the overall economic conditions. We determined that the fair value was greater than book value for all three reporting units, and therefore goodwill was not considered impaired. We will continue to monitor the market to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary. Since adoption of SFAS 142, we have not recognized any impairment of goodwill.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

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

	Transportation	Facilities	Marketing	Total
Balance at December 31, 2006	$ 399	$ 249	$ 378	$1,026
2007 Additions				
Pacific(1)	—	30	2	32
Other(2)	5	4	5	14
Balance at December 31, 2007	$ 404	$ 283	$ 385	$1,072
2008 Additions				
Rainbow	194	—	—	194
Other(2)	(36)	—	(20)	(56)
Balance at December 31, 2008	$ 562	$ 283	$ 365	$1,210

(1) Change is due to purchase price adjustments.

(2) Includes goodwill specific to other acquisitions made during 2007, as well as (i) foreign currency translation adjustments, (ii) payment of additional consideration related to an earn-out clause in a prior acquisition and (iii) other immaterial items.

Other assets, net

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

	2008	2007
Debt issue costs	$ 34	$ 28
Fair value of derivative instruments	148	26
Intangible assets	191	124
Other	10	18
	383	196
Less accumulated amortization	(37)	(27)
	$346	$169

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 $7 million and $1 million in 2008 and 2007, respectively.

Amortization expense related to other assets (including finite-lived intangible assets) for each of the three years in the period ended December 31, 2008 was $21 million, $13 million and $9 million, respectively. Our amortization expense for finite-lived intangible assets for the years ended December 31, 2008, 2007 and 2006 was $15 million, $10 million and $5 million, respectively.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

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, 2008			December 31, 2007		
		Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
Customer contracts and relationships	4-17	$151	$ (24)	$127	$ 84	$ (12)	$ 72
Emission reduction credits[1]	N/A	40	—	40	34	—	34
Environmental permits	2	—	—	—	6	(4)	2
		$191	$ (24)	$167	$124	$ (16)	$108

(1) Emission reduction credits are finite-lived and are subject to amortization from the date that they are first utilized. At December 31, 2008, none of our emission reduction credits were being utilized because the projects for which they were acquired are not in service.

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

2009	$12
2010	10
2011	9
2012	9
2013	9

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 12 for further discussion of environmental remediation matters.

Income and Other Taxes

See Note 7 for discussion of U.S. federal and state taxes and Canadian federal and provincial taxes.

We estimate (i) income taxes in the jurisdictions in which we operate, (ii) net deferred tax assets and liabilities based on expected future taxes in the jurisdictions in which we operate, (iii) valuation allowances for deferred tax assets and (iv) contingent tax liabilities for estimated exposures related to

Note 2—Summary of Significant Accounting Policies (Continued)

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.

As of December 31, 2007, we did not record a valuation allowance against our deferred tax assets for federal net operating loss carryforwards. Management believed that it was more likely than not that we would realize the deferred tax assets associated with the federal net operating loss. These net operating losses have since been used to offset taxable income.

Recent Accounting Pronouncements

Standards Adopted as of January 1, 2009

In November 2008, the EITF issued Issue No. 08-06, "Equity Method Investment Accounting Considerations" ("EITF 08-06"). EITF 08-06 addresses certain accounting considerations, including initial measurement, decreases in investment value, and changes in the level of ownership or degree of influence related items related to equity method investments. The provisions of EITF 08-06 will be effective for fiscal years beginning on or after December 15, 2008 and will be applied prospectively. We adopted EITF 08-06 on January 1, 2009 and are currently evaluating the impact of adoption on our consolidated financial statements.

In April 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") No. FAS 142-3 "Determination of the Useful Life of Intangible Assets" ("FSP No. FAS 142-3"). FSP No. FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS 142. The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141 (revised 2007), "Business Combinations," and other generally accepted accounting principles. This FSP will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted the FSP on January 1, 2009 and are currently evaluating the impact of adoption on our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities—an Amendment of FASB Statement No. 133" ("SFAS 161"). SFAS 161 requires enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS 133, and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 will be effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted SFAS 161 on January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In March 2008, the EITF issued Issue No. 07-04, "Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships" ("EITF 07-04"). EITF 07-04 addresses the application of the two-class method under SFAS No. 128, "Earnings Per Share" in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions. The two-class method is an earnings allocation formula that determines earnings per unit for each class of common units and participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. EITF 07-04 will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted EITF 07-04 on January 1, 2009. Adoption will impact the net income available to limited partners used in our computation of EPU but will not impact our distributions to limited partners, financial position, results of operations or cash flows.

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 adopted SFAS 160 on January 1, 2009. Such adoption did not 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 adopted SFAS 141(R) on January 1, 2009. Adoption will impact our accounting for acquisitions subsequent to that date.

Standards Adopted as of January 1, 2008

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, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. The provisions of SFAS 159 were effective for fiscal years beginning after November 15, 2007. We adopted SFAS 159 on January 1, 2008, but did not make any elections to value any eligible assets or liabilities at fair value and thus the adoption did not have any impact on our consolidated financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS 157, which defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. The provisions of SFAS 157 were deferred for one year for certain non-financial assets and non-financial liabilities, including asset retirement obligations, goodwill, intangible assets and long-lived assets. We adopted SFAS 157 as of January 1, 2008 with the exception of those assets and liabilities that are subject to the deferral. The provisions of SFAS 157 are to be applied prospectively and require new disclosures regarding the level of pricing observability associated with financial instruments carried at fair value. See Note 6 for additional disclosure.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

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 foreign currency risk. We record all open derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of 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 in 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

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 EITF 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.

Effective January 1, 2009, we adopted EITF 07-04 and EITF 03-06 will no longer be applied. See "Recent Accounting Pronouncements" above for further discussion.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2—Summary of Significant Accounting Policies (Continued)

The following sets forth the computation of basic and diluted earnings per limited partner unit under EITF 03-06. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents.

	Year Ended December 31, 2008	2007 (amounts in millions, except per unit data)	2006
Numerator for basic and diluted earnings per limited partner unit:			
Net income	$ 437	$ 365	$ 285
Less: General partner's incentive distribution paid	(106)	(73)	(33)
Subtotal	331	292	252
Less: General partner 2% ownership	(6)	(6)	(5)
Net income available to limited partners	325	286	247
Less: Pro forma EITF 03-06 additional general partner's distribution	—	—	(11)
Net income available to limited partners under EITF 03-06	325	286	236
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	$ 325	$ 286	$ 230
Denominator:			
Basic weighted average number of limited partner units outstanding	120	113	81
Effect of dilutive securities:			
Weighted average LTIP units(1)	1	1	1
Diluted weighted average number of limited partner units outstanding	121	114	82
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 2.70	$ 2.54	$ 2.84
Cumulative effect of change in accounting principle per limited partner unit	—	—	0.07
Basic net income per limited partner unit	$ 2.70	$ 2.54	$ 2.91
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 2.67	$ 2.52	$ 2.81
Cumulative effect of change in accounting principle per limited partner unit	—	—	0.07
Diluted net income per limited partner unit	$ 2.67	$ 2.52	$ 2.88

(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.

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.

2008 Acquisitions

Rainbow. In May 2008, we completed the acquisition of Rainbow Pipe Line Company, Ltd. ("Rainbow") for approximately $687 million (the Canadian dollar ("CAD") to U.S. dollar foreign exchange rate at the date of closing was $0.993:1). The assets acquired include approximately (i) 480 miles of mainline crude oil pipelines, (ii) 119 miles of gathering pipelines, (iii) 570,000 barrels of tankage along the system and (iv) 1 million barrels of crude oil linefill. The system has a throughput capacity of approximately 200,000 barrels per day and has transported approximately 193,000 barrels per day since acquisition. The acquired operations are reflected primarily in our transportation segment. The goodwill associated with this acquisition was approximately $194 million. In anticipation of closing the Rainbow acquisition, we entered into forward currency exchange contracts, which exchanged Canadian dollars and U.S. dollars, to hedge the foreign currency exchange risk inherent in the acquisition price. Additionally, we entered into a financial option strategy, whereby we established a minimum and maximum per barrel price to hedge the commodity price risk associated with the anticipated purchase of crude oil linefill. We recognized a gain on those positions of approximately $8 million and $3 million, respectively, which is reflected in our consolidated results of operations in the "Interest income and other income (expense), net" line.

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

Cash payment to sellers	$659
Assumption of Rainbow debt (at fair value)	26
Transaction costs	2
Total purchase price	$687

The purchase price allocation is as follows (in millions):

Property, plant and equipment	$	425
Pipeline linefill in owned assets		143
Intangible assets		52
Goodwill		194
Future income tax liability		(110)
Assumption of working capital and other long-term assets and liabilities, including cash[(1)]		(17)
Total	$	687

(1) Includes approximately $16 million associated with environmental liabilities.

During 2008, we completed one additional acquisition for aggregate consideration of approximately $44 million. This acquisition is reflected in our facilities segment and included the purchase of a storage facility and other assets. There was no goodwill associated with this acquisition.

Note 3—Acquisitions and Dispositions (Continued)

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, resulting in the issuance of approximately 22 million Partnership units. 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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3—Acquisitions and Dispositions (Continued)

The purchase price allocation is as follows (in millions):

Property, plant and equipment, net	$1,385
Investment in Frontier	18
Inventory	34
Pipeline linefill and long-term inventory	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 for further discussion regarding our goodwill accounting policy.

(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

Note 3—Acquisitions and Dispositions (Continued)

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.

The aggregate purchase price of these acquisitions was allocated as follows (in millions):

Inventory	$ 35
Linefill	19
Long-term inventory	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 for further discussion regarding our goodwill accounting policy.

(2) Consists of customer relationships.

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3—Acquisitions and Dispositions (Continued)

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. 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 (in millions, except per unit data).

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

Dispositions

During 2008, 2007 and 2006, we sold various property and equipment for proceeds totaling approximately $12 million, $13 million and $4 million, respectively. A gain of approximately $6 million, a loss of approximately $7 million and a gain of $2 million were recognized in 2008, 2007 and 2006, respectively related to these sales.

Note 4—Debt

Debt consists of the following (in millions):

	December 31, 2008	December 31, 2007
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.3% and 5.3% at December 31, 2008 and 2007, respectively	$ 280	$ 476
Senior unsecured revolving credit facility, bearing interest at a rate of 1.1% and 5.5% at December 31, 2008 and 2007, respectively[(1)]	746	482
Other	1	2
Total short-term debt	1,027	960
Long-term debt:		
4.75% senior notes due August 2009[(2)]	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
6.50% senior notes due May 2018	600	—
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized premium/(discount), net	(6)	(2)
Long-term debt under senior unsecured revolving credit facility and other[(1)]	40	1
Total long-term debt[(1)(3)]	3,259	2,624
Total debt	$ 4,286	$ 3,584

(1) At December 31, 2008 and 2007, we have classified $746 million and $482 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) In August 2009, our $175 million 4.75% senior notes will mature. However, since we have the ability and intent to refinance those notes, they are classified as long-term debt within our balance sheet.

(3) At December 31, 2008, the aggregate fair value of our fixed-rate senior notes was estimated to be approximately $2,700 million. Our fixed-rate senior notes are traded among institutions, which trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near year end.

Credit Facilities

We entered into a new $525 million senior secured hedged inventory facility during November 2008, which matures in November 2009. The new committed facility replaced a $1.2 billion uncommitted facility that was scheduled to mature in November 2008, and also includes an accordion

Note 4—Debt (Continued)

feature which enables us to increase the size of the facility to $1.2 billion, subject to obtaining additional lender commitments. Initial proceeds from the new committed facility were used to refinance the outstanding balance of the previous uncommitted facility and subsequent proceeds will be used to finance purchased or stored hedged inventory. Obligations under the new committed facility are secured by the financed inventory and the associated accounts receivable, and will be repaid from the proceeds of the sale of the financed inventory. The new facility will mature on an annual basis beginning in November 2009 and, except for increased pricing and it being committed, bears similar terms to the previous facility. At December 31, 2008, borrowings of approximately $280 million were outstanding under this facility. At December 31, 2007, borrowings of approximately $476 million were outstanding under our previous $1.2 billion uncommitted hedged inventory facility.

As of December 31, 2008 and 2007, 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). This credit facility has a maximum debt coverage ratio of 4.75 to 1.0 (5.5 to 1.0 during an acquisition period) and a 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, 2008 and 2007, amounts outstanding under this facility and together with committed letters of credit were $836 million and $635 million, respectively.

Senior Notes

In April 2008, we completed the issuance of $600 million of 6.5% Senior Notes due May 1, 2018. The senior notes were sold at 99.424% of face value. Interest payments are due on May 1 and November 1 of each year. We used the net proceeds from the offering to repay amounts outstanding under our credit facilities. In November 2008, the outstanding senior notes were exchanged for similar notes registered under the Securities Act.

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 entered into $200 million of notional principal amount 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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4—Debt (Continued)

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 13 for discussion of our guarantors and non-guarantors.

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 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, 2008 and 2007, we had outstanding letters of credit of approximately $51 million and $153 million, respectively.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4—Debt (Continued)

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2008 was approximately 12 years and the aggregate maturities for the next five years are as follows (in millions):

Calendar Year	Payment
2009	$ 175
2010	—
2011	—
2012	239
2013	250
Thereafter	2,600
Total(1)	$ 3,264

(1) Excludes aggregate unamortized net discount of $6 million and an adjustment of $1 million related to a fair value hedge.

Note 5—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2008 consists of 122,911,645 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.

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 and Rainbow acquisitions, our general partner agreed to reduce the amounts due it as incentive distribution. The total reduction in incentive distributions related to these acquisitions is $75 million. Following the distribution in February 2009, the aggregate remaining incentive distribution reductions related to these acquisitions will be $31 million.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5—Partners' Capital and Distributions (Continued)

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

	Year					
	2008		2007		2006	
	Distribution(1)	Excess over MQD	Distribution(1)	Excess over MQD	Distribution(1)	Excess over MQD
First Quarter	$ 0.8500	$ 0.4000	$ 0.8000	$ 0.3500	$ 0.6875	$0.2375
Second Quarter	$ 0.8650	$ 0.4150	$ 0.8125	$ 0.3625	$ 0.7075	$0.2575
Third Quarter	$ 0.8875	$ 0.4375	$ 0.8300	$ 0.3800	$ 0.7250	$0.2750
Fourth Quarter	$ 0.8925	$ 0.4425	$ 0.8400	$ 0.3900	$ 0.7500	$0.3000

(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				
		General Partner			
Year	Common Units	Incentive	2%	Total	Distributions per limited partner unit
2008	$ 418	$ 106	$8	$ 532	$ 3.50
2007	$ 370	$ 73	$8	$ 451	$ 3.28
2006	$ 225	$ 33	$5	$ 263	$ 2.87

On January 14 , 2009, we declared a cash distribution of $0.8925 per unit on our outstanding common units. The distribution was paid on February 13, 2009 to unitholders of record on February 3, 2009, for the period October 1, 2008 through December 31, 2008. The total distribution paid was approximately $140 million, with approximately $110 million paid to our common unitholders and $2 million and $28 million paid to our general partner for its general partner and incentive distribution interests, respectively.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5—Partners' Capital and Distributions (Continued)

Equity Offerings

During the three years ended December 31, 2008, we completed the following equity offerings of our common units (in millions, except per unit data):

Period	Units Isssued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds[1]
April 2008[2]	6,900,000	$ 46.31	$ 320	$ 6	$(11)	$ 315
2008 Total	**6,900,000**		**$ 320**	**$ 6**	**$(11)**	**$ 315**
June 2007[3]	6,296,172	$ 59.56	$ 375	$ 8	$ —	$ 383
2007 Total	**6,296,172**		**$ 375**	**$ 8**	**$ —**	**$ 383**
December 2006[3][4]	6,163,960	$ 48.67	$ 300	$ 6	$ —	$ 306
July/August 2006[3][4]	3,720,930	$ 43.00	160	3	—	163
March/April 2006[3][4]	3,504,672	$ 42.80	150	3	(1)	152
2006 Total	**13,389,562**		**$ 610**	**$ 12**	**$ (1)**	**$ 621**

(1) Net proceeds for 2006 exclude the common units issued and our general partner's proportionate capital contribution of $22 million pertaining to the equity exchange for the Pacific acquisition.

(2) The April 2008 offering of common units was an underwritten transaction that required us to pay a gross spread.

(3) These offerings were direct placements of common units, did not involve underwriters and did not require a gross spread. However, the gross unit price includes the discount to market required to execute these transactions.

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

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 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, 2008, approximately 154,000 Class B units have been granted and the remaining units are reserved for future grants. See Note 10 for further discussion of Class B units.

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

Note 6—Derivatives and Hedging Instruments (Continued)

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 instruments that qualify for hedge accounting are designated as 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. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

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, 2008	December 31, 2007
Other current assets	$ 231	$ 56
Other long-term assets	148	26
Other current liabilities	(319)	(97)
Other long-term liabilities and deferred credits	(72)	(22)
Other	—	1
Net Liability	$ (12)	$(36)

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 parentheses):

	December 31, 2008			December 31, 2007		
	Net Asset (Liability)	Earnings	AOCI	Net Asset (Liability)	Earnings	AOCI
Commodity price risk hedging	$ (30)	$ 57	$ (87)	$ (38)	$ (48)	$ 10
Controlled trading program	—	—	—	—	—	—
Interest rate risk hedging	5	5	—	3	3	—
Currency exchange rate risk hedging	13	(3)	16	(1)	—	(1)
	$ (12)	$ 59	$ (71)	$ (36)	$ (45)	$ 9

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 6—Derivatives and Hedging Instruments (Continued)

In addition to the net liability related to open derivative positions of $71 million, AOCI also includes deferred gains on settled hedges and other items. The following table summarizes our total net deferred gains in AOCI associated with derivitive instruments (in millions):

	December 31, 2008	December 31, 2007
Deferred gains and (losses) on open hedges	$ (71)	$ 9
Deferred gains and (losses) on settled hedges	237	(5)
Reclassification to earnings for open inventory hedges associated with lower-of-cost-or-market adjustments	(5)	—
Total AOCI deferred gain associated with derivitive instruments	$161	$ 4

The total amount of deferred net gain recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the related physical purchase or delivery of the underlying commodity, (ii) interest expense accruals associated with the underlying debt instruments and (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD denominated intercompany interest receivables. Of the total net gain deferred in AOCI at December 31, 2008, a net gain of approximately $67 million will be reclassified to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 83% is expected to be reclassified to earnings prior to 2012 with the remaining deferred gain being reclassed to earnings through 2018. 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, 2008, and in conjunction with the closing of our Rainbow acquisition, we initially anticipated the sale of 350,000 barrels of crude oil linefill and hedged the commodity price risk associated with the anticipated sale. Upon our determination that the anticipated sale was no longer probable of occurring, we discontinued hedge accounting and reclassed a deferred gain of $17 million from AOCI to crude oil, refined products and LPG sales. During the year ended December 31, 2007, no amounts were reclassified to earnings from AOCI in connection with forecasted transactions that were no longer considered probable of occurring. We recognized a loss in crude oil, refined products and LPG sales of approximately $1 million during each of the years ended December 31, 2008 and December 31, 2007 associated with cash flow hedge ineffectiveness.

We do not enter into master netting agreements with our derivative counterparties, nor do we offset the assets and liabilities associated with the fair value of our derivatives with amounts we have recognized related to our right to receive or our obligation to pay cash collateral. When we deposit cash collateral with our brokers, we recognize a broker receivable, which is a component of our accounts receivable. Our broker receivable was approximately $81 million and $16 million as of December 31, 2008 and December 31, 2007, respectively.

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

Commodity Price-Risk Hedging

We use derivative instruments to 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, options and swaps traded

Note 6—Derivatives and Hedging Instruments (Continued)

on the NYMEX, ICE and in over-the-counter transactions, including commodity 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 instruments that qualify for hedge accounting are designated as 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.

Controlled Trading Program

Although we seek to maintain a position that is substantially balanced within our marketing 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. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time. 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 and a substantially lesser amount for LPG. 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

As of December 31, 2008, AOCI includes a total deferred loss of approximately $7 million that relates to terminated interest rate swaps and "treasury locks" (a financial derivative instrument that enables a company to lock in the U.S. Treasury Note rate) 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.

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. Our counterparties may exercise their call option on June 15, 2009 by paying us $3 million. 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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 6—Derivatives and Hedging Instruments (Continued)

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments may include forward exchange contracts, swaps and options. At December 31, 2008, our open foreign exchange derivatives consisted of forward exchange contracts that exchange CAD and U.S. dollars on a net basis as follows (in millions):

	CAD	U.S. Dollars	Average Exchange Rate
2009	$43	$ 38	CAD $1.12 to US $1.00
2010	$25	$ 25	CAD $1.00 to US $1.00
2011	$25	$ 25	CAD $1.00 to US $1.00
2012	$25	$ 25	CAD $1.00 to US $1.00
2013	$19	$ 19	CAD $1.00 to US $1.00

These financial instruments are placed with large, highly rated financial institutions.

In anticipation of closing the Rainbow acquisition, we entered into a forward currency exchange contract, which exchanged Canadian dollars and US dollars, to hedge the foreign currency exchange risk inherent in the acquisition price. In May 2008, we settled the forward contract, which resulted in a gain of approximately $8 million.

Upon closing of the Rainbow acquisition, we entered into a CAD-denominated intercompany note. In order to hedge the foreign currency exposure on the interest payments, we entered into forward currency exchange contracts. In October 2008, we settled half of these instruments which resulted in a gain of approximately $17 million, which is deferred in AOCI.

Adoption of SFAS 157

Effective January 1, 2008, we adopted SFAS 157 which, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in SFAS 157, fair value is the price that would be received from selling an asset, or paid to transfer a liability, in an orderly transaction between market participants at the measurement date. Whenever possible, we use market data that market participants would use when pricing an asset or liability. These inputs can be either readily observable or market corroborated. We apply the market approach for recurring fair value measurements related to our derivatives. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a

Note 6—Derivatives and Hedging Instruments (Continued)

particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

Recurring Fair Value Measures	Fair Value as of December 31, 2008 (in millions)			
	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivatives	$ 235	$ 9	$ 112	$ 356
Interest rate derivatives	—	—	5	5
Foreign currency derivatives	—	—	18	18
Total assets at fair value	$ 235	$ 9	$ 135	$ 379
Liabilities:				
Commodity derivatives	$(330)	$ —	$ (56)	$(386)
Foreign currency derivatives	—	—	(5)	(5)
Total liabilities at fair value	$(330)	$ —	$ (61)	$(391)
Net asset/(liability) at fair value	$ (95)	$ 9	$ 74	$ (12)

The determination of the fair values above incorporates various factors required under SFAS 157. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives, interest rate derivatives and foreign currency derivatives includes adjustments for credit risk. We measure credit risk by deriving a probability of default from market observed credit default swap spreads as of the measurement date. The probability of default is applied to the net credit exposure of each of our counterparties and includes a recovery rate adjustment. The recovery rate is an estimate of what would ultimately be recovered through a bankruptcy proceeding in the event of default. Fair value adjustments related to counterparty credit risk resulted in a net deferred loss of $1 million in AOCI during the year ended December 31, 2008. There were no changes to any of our valuation techniques during the period.

Level 1

Included within level 1 of the fair value hierarchy are commodity derivatives that are exchange traded. Exchange-traded derivative contracts include futures, options and swaps. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets and is therefore classified within level 1 of the fair value hierarchy.

Level 2

Included within level 2 of the fair value hierarchy is a physical commodity supply contract that meets the definition of a derivative but is not excluded from SFAS 133 under the normal purchase and normal sale scope exception. The fair value of this commodity derivative is measured with level 1 inputs for similar but not identical instruments and therefore must be included in level 2 of the fair value hierarchy.

Note 6—Derivatives and Hedging Instruments (Continued)

Level 3

Included within level 3 of the fair value hierarchy are (i) commodity derivatives that are not exchange traded, (ii) interest rate derivatives and (iii) foreign currency derivatives, which are described as follows:

- Commodity Derivatives: Level 3 commodity derivatives include over-the-counter commodity derivatives such as forwards, swaps and options and certain physical commodity contracts. The fair value of our level 3 derivatives is based on either an indicative broker or dealer price quotation or a valuation model. Our valuation models utilize inputs such as price, volatility and correlation and do not involve significant management judgments.

- Interest Rate Derivatives: Level 3 interest rate derivatives include interest rate swaps. The fair value of our interest rate derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward LIBOR curves and forward Treasury yields that are obtained from pricing services.

- Foreign Currency Derivatives: Level 3 foreign currency derivatives include foreign currency swaps, forward exchange contracts and options. The fair value of our foreign currency derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward CAD/USD forward exchange rates that are obtained from pricing services.

The majority of the derivatives included in level 3 of the fair value hierarchy are classified as level 3 because the broker or dealer price quotations used to measure fair value and the pricing services used to corroborate the quotations are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these level 3 derivatives is not based upon significant management assumptions or subjective inputs.

Note 6—Derivatives and Hedging Instruments (Continued)

Rollforward of Level 3 Net Liability

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives measured at fair value using inputs classified as level 3 in the fair value hierarchy (in millions):

	Year Ended December 31, 2008
Balance as of January 1, 2008	$ (21)
Realized and unrealized gains (losses):	
Included in earnings[1]	68
Included in other comprehensive income	35
Purchases, issuances, sales and settlements	(8)
Transfers into or out of level 3[2]	—
Balance as of December 31, 2008	$ 74
Change in unrealized gains (losses) included in earnings relating to level 3 derivatives still held as of December 31, 2008[3]	$ 44

(1) Gains and losses associated with level 3 commodity derivatives are reported in our condensed consolidated statements of operations as crude oil, refined products and LPG sales or purchases. Gains and losses associated with interest rate derivatives are reported in our condensed consolidated statements of operations as other income (expense). Gains and losses associated with foreign currency derivatives are reported in our condensed consolidated statements of operations as either crude oil, refined products and LPG sales or other income (expense).

(2) Transfers into or out of level 3 represent existing assets or liabilities that were either previously categorized at a higher level for which the inputs to the model became unobservable or that were previously classified as level 3 for which the lowest significant input became observable during the period. There were no transfers into or out of level 3 during the period.

(3) The change in unrealized gains and losses related to our level 3 assets and liabilities still held at the end of the period are either recognized in earnings or deferred in AOCI through the application of hedge accounting. Unrealized gains and losses related to our level 3 derivatives that are still held at December 31, 2008 and recognized in earnings are included in our condensed consolidated statements of operations as crude oil, refined products and LPG sales for our commodity derivatives, other income (expense) for our interest rate derivatives and crude oil, refined products and LPG sales or other income (expense) for our foreign currency derivatives.

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and are therefore offset by the underlying transactions.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. Although, we are subject to state income taxes in some states, the impact to the years ended December 31, 2008, 2007 and 2006 was immaterial.

Canadian Federal and Provincial Taxes

Certain of our Canadian subsidiaries 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 treated as a flow-through entity for tax purposes. This entity is subject to Canadian legislation passed in June 2007 that imposes entity-level taxes on certain types of flow-through entities. This legislation includes safe harbor guidelines that grandfather certain existing entities (which, we believe, would include us) and delay the effective date of such legislation until 2011 provided that such entities do not exceed the normal growth guidelines. Although we continuously review acquisition opportunities that, if consummated, could cause us to exceed the normal growth guidelines, we believe that we are currently within the normal growth guidelines. At the time of enactment of the legislation in June 2007, we recognized a net deferred income tax liability of approximately $10 million. This amount represented the estimated tax effect of temporary differences that existed at that time and that were expected to reverse after the date that this legislation is effective for us based on the 28% weighted average tax rate that we expect 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 equipment.

We file Canadian federal and provincial tax returns. Generally, we are no longer subject to Canadian federal and provincial income tax examinations for years before 2005.

Tax Components

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

	Yeare Ended December 31,		
	2008	2007	2006
Current tax expense:			
State income tax	$ 1	$ 1	$ —
Canadian federal and provincial income tax	8	2	—
Total current tax expense	$ 9	$ 3	$ —
Deferred tax (benefit)/expense:			
State income tax	$—	$ 1	$ —
Canadian federal and provincial income tax	(1)	12	—
Total deferred tax (benefit)/expense	$ (1)	$13	$ —
Total income tax expense	$ 8	$16	$ —

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7—Income Taxes (Continued)

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

	Year Ended December 31,		
	2008	2007	2006
Income before tax	$ 445	$ 381	$ 285
Partnership earnings not subject to current Canadian tax	(422)	(369)	(285)
	$ 23	$ 12	$ —
Canadian federal and provincial corporate tax rate	29.5%	32.1%	32.5%
Income tax at statutory rate	$ 7	$ 4	$ —
Canadian deferred tax as a result of book versus tax differences	4	(2)	—
Canadian permanent differences between book and tax	(3)	—	—
State income tax	1	1	—
Current income tax expense	$ 9	$ 3	$ —
State deferred income tax	—	1	—
Canadian corporation deferred tax as a result of book versus tax differences	(4)	2	—
Flow-through entities deferred tax as a result of book versus tax differences	3	10	—
Deferred income tax (benefit)/expense	$ (1)	$ 13	$ —
Total income tax expense	$ 8	$ 16	$ —

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

	December 31,	
	2008	2007
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 9	$ 5
Net operating losses carried forward	—	4
Total deferred tax assets	9	9
Deferred tax liabilities:		
Canadian partnership income subject to deferral	—	(4)
Property, plant and equipment in excess of tax values	(118)	(29)
Total deferred tax liabilities	(118)	(33)
Net deferred tax liabilities	$(109)	$(24)

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7—Income Taxes (Continued)

interest and penalties related to uncertain tax positions in income tax expense. At December 31, 2008 and 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 accounted for 14%, 19% and 14% of our revenues for each of the three years ended December 31, 2008, 2007 and 2006, respectively. Valero Marketing & Supply Company accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 12% and 11% of our revenues for the years ended December 31, 2008 and 2007, respectively. 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 (other than expenses related to the Class B units of Plains AAP, L.P.). 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, 2008, 2007 and 2006 were $289 million, $287 million and $205 million, respectively.

Vulcan Energy Corporation

As of December 31, 2008, Vulcan Energy Corporation ("Vulcan Energy") and its affiliates owned approximately 50% of our general partner interest, as well as approximately 10% 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, Vulcan Energy's ownership interest increased from 44% to over 50%. 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. Beginning in October 2008, the Services Agreement automatically renews 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 directly or indirectly use any knowledge or

Note 9—Related Party Transactions (Continued)

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 August 2005 to May 2007, Calumet Florida L.L.C ("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 paid approximately $45 million to Calumet for crude oil purchases in 2006.

Investment in PAA/Vulcan Gas Storage, LLC

PAA/Vulcan, a limited liability company, was formed in 2005. We own 50% of PAA/Vulcan and the other 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan Capital Private Equity I LLC which is an affiliate of Vulcan Energy. W. Lance Conn, a member of our board of directors, has 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. 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. 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.

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"). We have 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. At the time of delivery, the base gas will be sold to PAA/Vulcan at the average price that we pay for the base gas (including hedge gains or losses) and we will not recognize any gain or loss. 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 and other agreements. 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

Note 9—Related Party Transactions (Continued)

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 2008 and 2007, we contributed an additional $37 million and $9 million, respectively, to PAA/Vulcan. During 2008, we received distributions of approximately $7 million from PAA/Vulcan; no such distributions were received during 2007. Vulcan Gas Storage made the same net contribution as we did during 2008 and 2007. Such contributions and distributions did not result in an increase or decrease to our ownership interest. In connection with the construction financing for development of the Pine Prairie storage facility, we and Vulcan Gas Storage have committed to make future aggregate capital contributions up to a maximum of $17.5 million each.

In conjunction with the formation of PAA/Vulcan, 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 million over ten years from PAA/Vulcan (distributions that would otherwise have been paid to Vulcan Gas Storage). 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 reimburses 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% of which were sold to investment funds affiliated with Kayne Anderson Capital Advisors, L.P. ("KACALP") and 10% to EnCap Investments, L.P. 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. 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), an affiliate of EnCap and an affiliate of Vulcan Capital each have a representative on our board of directors.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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- 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 million 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, 2008 we have the following LTIP awards outstanding (units in millions):

LTIP Units Outstanding	Vesting Distribution Amount	Estimated Unit Vesting Date			
		2009	2010	2011	2012
1.3(1)	$3.20	0.6	0.7	—	—
1.3(2)	$3.50 - $4.50	—	—	0.8	0.5
1.3(3)	$3.50 - $4.00	—	0.8	0.1	0.4
3.9(4)(5)		0.6	1.5	0.9	0.9

(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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10—Equity Compensation Plans (Continued)

(2) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.50 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. For purposes of this disclosure, the awards are presented above assuming the distribution levels are attained and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(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. For purposes of this disclosure, the awards are presented above assuming the distribution levels are attained and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(4) Approximately 2.1 million of our approximately 3.9 million outstanding LTIP awards also include DERs, of which 1.2 million are currently earned.

(5) LTIP units outstanding do not include Class B units of Plains AAP, L.P. described below.

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

	Year Ended December 31,					
	2008		2007		2006	
	Units	Weighted Average Grant Date Fair Value per Unit	Units	Weighted Average Grant Date Fair Value per Unit	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding at beginning of period	3.6	$ 37.75	3.0	$ 31.94	2.2	$ 34.37
Granted	0.5	31.79	1.6	47.25	0.9	26.00
Vested	(0.1)	32.44	(0.7)	34.86	—	—
Cancelled or forfeited	(0.1)	36.14	(0.3)	36.00	(0.1)	33.05
Outstanding at end of period	3.9	$ 36.44	3.6	$ 37.75	3.0	$ 31.94

Our accrued liability at December 31, 2008 related to all outstanding LTIP awards and DERs is approximately $55 million, which includes an accrual associated with our assessment that an annualized distribution of $3.75 is probable of occurring. We have not deemed a distribution of more than $3.75 to be probable. At December 31, 2007, the accrued liability was approximately $51 million.

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 200,000 Class B units of Plains AAP, L.P. to be administered by the compensation committee. 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 (as adjusted for debt service costs and excluding special distributions funded by debt) 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 (as adjusted) each quarter. At December 31, 2008 and 2007, 154,000 Class B units were outstanding and 46,000 Class B units were reserved for future grants. In August 2008, 21,000 Class B units were earned upon the payment of our second quarter distribution of $0.8875 per unit and an additional 17,500 were earned in February 2009. 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, 2008 and 2007 was approximately $34 million of which approximately $13 million and $3 million was recognized as expense during the years ended December 31, 2008 and 2007, respectively.

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):

	Year Ended December 31,		
	2008	2007	2006
Equity compensation expense	$ 24	$ 49	$ 43
LTIP unit vestings	$ 1	$ 17	$ 1
LTIP cash settled vestings	$ 2	$ 16	$ 2
DER cash payments	$ 4	$ 4	$ 3

Approximately 0.3 million units were issued in 2007 in connection with the settlement of vested awards. The remaining 0.1 million and 0.4 million of awards that vested during 2008 and 2007, respectively, were settled in cash. There was an insignificant amount of units issued in connection with the settlement of vested awards in 2006. As of December 31, 2008 and 2007, the weighted average remaining contractual life of our outstanding LTIP awards was approximately two years based on expected vesting dates. Based on the December 31, 2008 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $41 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 $34.69 at December 31, 2008. Actual amounts may differ materially as a result of a change in the market price of our units and/or

Note 10—Equity Compensation Plans (Continued)

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)(2)
2009	$ 19
2010	15
2011	5
2012	2
2013	—
Total	$ 41

(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, 2008.

(2) Includes unamortized fair value associated with Class B units of Plains AAP, L.P.

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, 2008, are summarized below (in millions):

2009	$ 57
2010	46
2011	40
2012	35
2013	26
Thereafter	204
Total	$408

Expenditures related to leases for 2008, 2007 and 2006 were $82 million, $51 million and $38 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 location of the Pecos

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11—Commitments and Contingencies (Continued)

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 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 releases. We may also be subjected to injunctive remedies that would impose additional requirements, costs 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. Such statutes contemplate the potential for substantial reduction in penalties based on mitigating circumstances and factors. We believe that several of such circumstances and factors exist, and thus have been a primary focus in our discussions with the DOJ and EPA with respect to these matters.

SemCrude Bankruptcy. We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude. As a result of our statutory protections and contractual rights of setoff, substantially all of our pre-petition claims against SemCrude should be satisfied. Certain creditors of SemCrude and its affiliates have challenged our contractual and statutory rights to setoff certain of our payables to the debtor against our receivables from the debtor. The aggregate amount subject to challenge is approximately $62 million. We intend to vigorously defend our contractual and statutory rights.

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 the pipeline 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 and recovered under a pre-existing PPS pollution liability insurance policy.

In connection with this release, 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 alleged 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. On October 15, 2008 this criminal action (all four counts) was dismissed with prejudice and PPS was not subjected to any fine or penalty.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11—Commitments and Contingencies (Continued)

In September 2008, PPS was served by the State of California with a civil complaint in connection with this release, in the Los Angeles Superior Court Case No. BC398627, alleging violations of the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, violations of two sections of the California Water Code for the unlawful discharge of waste into state waters without a permit, and violations of the Public Nuisance Code alleging that discharge of petroleum into waters of the state had created a public nuisance. This case was settled in October 2008. Pursuant to the terms of the settlement agreement, PPS paid no fine or penalty, but made civil settlement payments to various agencies of the State of California in the total amount of approximately $1.1 million.

United States of America v. Pacific Pipeline System, LLC. In September 2008, the EPA filed a civil complaint against PPS in connection with the Pyramid Lake release. The complaint, which was filed in the Federal District Court for the Central District of California, Civil Action No. CV08-5768DSF(SSX), seeks the maximum permissible penalty under the relevant statutes of approximately $3.7 million. The EPA and DOJ have discretion to 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 may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We will defend against these charges. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty or fine that might be imposed by the EPA and DOJ, and intend to pursue discussions with the EPA and DOJ regarding such defenses and mitigating circumstances and factors. Although 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 on behalf of the EPA to resolve this matter have commenced.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE (and other petroleum product) contamination at the Pacific Atlantic Terminals LLC ("PAT") facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to $10 million. Both Exxon and GATX were prior owners of the terminal. We contend that Exxon and GATX are primarily responsible for the majority of the remediation costs. 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 are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the 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 mitigative costs or the imposition of fines and penalties. We have, for instance, recently settled numerous air permit violations alleged by the Bay Area Air Quality Management District.

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

Note 11—Commitments and Contingencies (Continued)

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 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 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, 2008, our reserve for environmental liabilities totaled approximately $42 million, of which approximately $8 million is classified as short-term and $34 million is classified as long-term. At December 31, 2008, we have recorded receivables totaling approximately $4 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

Note 11—Commitments and Contingencies (Continued)

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—Environmental Remediation

We currently own or lease, and in the past have owned and leased, 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) and to clean up contaminated property (including contaminated groundwater).

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 conjunction with our acquisitions, we make an assessment of potential environmental exposure and determine whether to negotiate an indemnity, what the terms of any indemnity should be and whether to obtain environmental risk insurance, if available. 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 former Texas New Mexico ("TNM") pipeline 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, of which we agreed in an arrangement with TNM to bear the first $11 million in costs of pre-May 1999 environmental issues. TNM also agreed to pay all costs in excess of $20 million (excluding certain deductibles). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). As of December 31, 2008, we had incurred approximately $9 million of remediation costs associated with these sites, while SOP's share is approximately $5 million. In another example, as a result of our merger with Pacific, we assumed liability for a number of ongoing remediation sites associated with releases from pipeline or storage operations. We have evaluated each of the sites

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 12—Environmental Remediation (Continued)

requiring remediation and developed reserve estimates for the Pacific sites, which total approximately $18 million at December 31, 2008.

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.

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

We have in the past experienced and in the future 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 for further environmental discussion.

Note 13—Supplemental Condensed Consolidating Financial Information

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 all subsidiaries other than the Non-Guarantor subsidiaries defined below; and
- "Non-Guarantor Subsidiaries" as of December 31, 2008 include: Pacific Pipeline System, LLC, Pacific Terminals, LLC, Pacific Energy Management LLC, Pacific Energy GP LP, PEG Canada GP LLC and SLC Pipeline LLC. The changes in non-guarantor subsidiaries during the years ended December 31, 2008, 2007 and 2006 were immaterial.

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

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, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,698	$ 2,789	$ 110	$ (3,001)	$ 2,596
Property plant and equipment, net	—	4,410	649	—	5,059
Investment in unconsolidated entities	4,388	895	—	(5,026)	257
Other assets	27	1,777	316	—	2,120
Total assets	$ 7,113	$ 9,871	$ 1,075	$ (8,027)	$ 10,032
LIABILITIES AND PARTNERS' CAPITAL					
Total current liabilities	$ 304	$ 5,411	$ 246	$ (3,001)	$ 2,960
Long-term debt	3,257	2	—	—	3,259
Other long-term liabilities	—	260	1	—	261
Total liabilities	3,561	5,673	247	(3,001)	6,480
Partners' Capital	3,552	4,198	828	(5,026)	3,552
Total liabilities and partners' capital	$ 7,113	$ 9,871	$ 1,075	$ (8,027)	$ 10,032

	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
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
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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Operations

	Year Ended December 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues[1]	$ —	$ 1,469	$ 113	$ —	$ 1,582
Field operating costs	—	(575)	(42)	—	(617)
General and administrative expenses	—	(149)	(11)	—	(160)
Depreciation and amortization	(3)	(187)	(21)	—	(211)
Operating income (loss)	(3)	558	39	—	594
Equity earnings in unconsolidated entities	629	45	—	(660)	14
Interest expense	(195)	(1)	—	—	(196)
Interest and other income (expense), net	6	26	1	—	33
Income tax expense	—	(8)	—	—	(8)
Net income (loss)	$ 437	$ 620	$ 40	$ (660)	$ 437

	Year Ended December 31, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	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 and other income (expense), net	5	5	—	—	10
Income tax expense	—	(16)	—	—	(16)
Net income (loss)	$ 365	$ 514	$ 61	$ (575)	$ 365

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Operations

	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 and other income (expense), net	2	—	—	—	2
Income tax expense	—	—	—	—	—
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)

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 437	$ 620	$ 40	(660)	$ 437
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	3	187	21	—	211
Inventory valuation adjustment	—	168	—	—	168
(Gains)/losses from derivative activities	—	(141)	—	—	(141)
Equity compensation expense	—	24	—	—	24
Gain on foreign currency revaluation		22			22
Equity earnings in unconsolidated entities, net of distributions	(622)	(42)	—	660	(4)
Deferred income tax benefit	—	(1)	—	—	(1)
Other	17	(15)	—	—	2
Changes in assets and liabilities, net of acquisitions	(375)	530	(16)	—	139
Net cash provided by (used in) operating activities	(540)	1,352	45	—	857
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions	—	(709)	—	—	(709)
Additions to property and equipment	—	(544)	(45)	—	(589)
Investment in unconsolidated entities	(37)	—	—	—	(37)
Net cash paid for linefill in assets owned		(55)			(55)
Proceeds from sales of assets	—	51	—	—	51
Net cash used in investing activities	(37)	(1,257)	(45)	—	(1,339)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings on revolving credit facility	204	82	—	—	286
Net repayments on short-term letter of credit and hedged inventory facility	—	(196)	—	—	(196)
Proceeds from the issuance of senior notes	597	—	—	—	597
Net proceeds from the issuance of common units	315	—	—	—	315
Distributions paid to common unitholders and general partner	(532)	—	—	—	(532)
Other financing activities	(6)	—	—	—	(6)
Net cash provided by (used in) financing activities	578	(114)	—	—	464
Effect of translation adjustment on cash	—	5	—	—	5
Net increase (decrease) in cash and cash equivalents	1	(14)	—	—	(13)
Cash and cash equivalents, beginning of period	1	23	—	—	24
Cash and cash equivalents, end of period	$ 2	$ 9	$ —	$ —	$ 11

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 13—Supplemental Condensed Consolidating Financial Information (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
(Gains)/losses on derivative activities	2	22	—	—	24
Equity compensation expense	—	49	—	—	49
Equity earnings in unconsolidated entities, net of distributions	(524)	(65)	—	575	(14)
Deferred income tax expense	—	13	—	—	13
Other	—	(14)	—	—	(14)
Changes in assets and liabilities, net of acquisitions	230	20	(57)	—	193
Net cash provided by operating activities	76	696	24	—	796
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions	—	(127)	—	—	(127)
Additions to property and equipment	—	(524)	(24)	—	(548)
Investment in unconsolidated entities	(9)	—	—	—	(9)
Net 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					
Net borrowings on revolving credit facility	—	305	—	—	305
Net repayments on short-term letter of credit and hedged inventory facility	—	(359)	—	—	(359)
Net proceeds from the issuance of common units	383	—	—	—	383
Distributions paid to common unitholders and general partner	(451)	—	—	—	(451)
Other financing activities	—	(2)	—	—	(2)
Net cash used in 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)

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Cash Flows

	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)
(Gains)/losses on derivative activities	—	4	—	—	4
Inventory valuation adjustment	—	6	—	—	6
Equity compensation expense	—	43	—	—	43
Equity earnings in unconsolidated entities, net of distributions	(362)	(14)	—	369	(7)
Loss on foreign currency revaluation	—	4	—	—	4
Other	—	—	—	—	—
Changes 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)
Net 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 revolving credit facility	(291)	(5)	—	—	(296)
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 common 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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 14—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total(1)
	(in millions, except per unit data)				
2008					
Revenues	$ 7,195	$ 9,060	$ 8,862	$ 4,943	$30,061
Gross margin(2)	167	132	282	173	754
Operating income	127	81	243	142	594
Net income	92	41	206	98	437
Basic net income per limited partner unit	$ 0.58	$ 0.13	$ 1.15	$ 0.56	$ 2.70
Diluted net income per limited partner unit	$ 0.57	$ 0.13	$ 1.14	$ 0.56	$ 2.67
Cash distributions per common unit(3)	$0.8500	$0.8650	$0.8875	$0.8925	$ 3.50
2007					
Revenues	$ 4,230	$ 3,918	$ 5,799	$ 6,447	$20,394
Gross margin(2)	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(3)	$0.8000	$0.8125	$0.8300	$0.8400	$ 3.28

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

(2) 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.

(3) Represents cash distributions declared and paid in the applicable period.

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 for the replacement of partially or fully depreciated

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15—Operating Segments (Continued)

assets in order to maintain the service capability, level of production, and/or functionality of our existing assets. Capital expenditures made to expand the existing earnings capacity of our assets are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (in millions).

	Transportation	Facilities	Marketing	Total
Twelve Months Ended December 31, 2008				
Revenues:				
External Customers	$ 556	$ 157	$ 29,348	$ 30,061
Intersegment[1]	371	113	2	486
Total revenues of reportable segments	$ 927	$ 270	$ 29,350	$ 30,547
Equity in earnings of unconsolidated entities	$ 5	$ 9	$ —	$ 14
Segment profit[2][3][4]	$ 445	$ 153	$ 221	$ 819
Capital expenditures	$ 935	$ 265	$ 26	$ 1,226
Total assets	3,930	2,048	4,054	10,032
Net gains/(losses) related to inventory valuation adjustments and derivative activities[2]	$ —	$ —	$ (4)	$ (4)
Maintenance capital	$ 54	$ 23	$ 4	$ 81
Twelve Months Ended December 31, 2007				
Revenues:				
External Customers	$ 439	$ 121	$ 19,834	$ 20,394
Intersegment[1]	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[2][3][4]	$ 334	$ 110	$ 269	$ 713
Capital expenditures	$ 255	$ 348	$ 47	$ 650
Total assets[5]	$ 3,127	$ 1,754	$ 5,025	$ 9,906
Net gains/(losses) related to inventory valuation adjustments and derivative activities[2]	$ —	$ —	$ (27)	$ (27)
Maintenance capital	$ 34	$ 10	$ 6	$ 50
Twelve Months Ended December 31, 2006				
Revenues:				
External Customers (includes buy/sell revenues of $0, $0, and $4,762, respectively)	$ 344	$ 41	$ 22,060	$ 22,445
Intersegment[1]	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[2][3][4]	$ 200	$ 35	$ 228	$ 463
Capital expenditures	$ 1,957	$ 1,323	$ 73	$ 3,353
Total assets[5]	$ 1,917	$ 1,348	$ 5,450	$ 8,715
Net gains/(losses) related to inventory valuation adjustments and derivative activities[2]	$ —	$ —	$ (4)	$ (4)
Maintenance capital	$ 20	$ 5	$ 3	$ 28

(1) Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15—Operating Segments (Continued)

(2) Gains/losses from derivative activities are included in marketing revenues and impact segment profit. The gain within the marketing segment for the year ended December 31, 2008 excludes a gain of $3 million related to foreign currency and interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit. The loss for the year ended December 31, 2007 includes a $2 million gain related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit.

(3) Marketing segment profit includes interest expense on contango inventory purchases of $21 million, $44 million and $49 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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

	Year ended December 31,		
	2008	2007	2006
Segment profit	$ 819	$ 713	$ 463
Depreciation and amortization	(211)	(180)	(100)
Interest expense	(196)	(162)	(86)
Interest income and other income (expense), net	33	10	2
Income tax expense	(8)	(16)	—
Income before cumulative effect of change in accounting principle	$ 437	$ 365	$ 279
Cumulative effect of change in accounting priciple	—	—	6
Net income	$ 437	$ 365	$ 285

(5) Certain reclassifications have been made to the balances as of December 31, 2007 and 2006 to conform to the current year presentation of intercompany balances to more accurately reflect total assets by segment.

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):

Revenues[(1)(2)]	For the Year Ended December 31, 2008	2007	2006
United States (includes buy/sell revenues of $4,170 for 2006)	$25,183	$16,843	$18,772
Canada (includes buy/sell revenues of $592 for 2006)	4,878	3,551	3,673
	$30,061	$20,394	$22,445

(1) Revenues are attributed to each region based on where the customers are located.

(2) Certain reclassifications have been made to the revenues for the years ended December 31, 2007 and 2006 to conform to the current year presentation of intercompany revenues to more accurately reflect revenues attributable to the respective geographic areas.

Long-Lived Assets[(1)]	As of December 31, 2008	2007
United States	$5,976	$5,407
Canada	1,312	800
	$7,288	$6,207

(1) Excludes long-term derivative assets.

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	—	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).
3.4	—	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).
3.5	—	Amendment No. 4 effective as of January 1, 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 April 15, 2008).
3.6	—	Amendment No. 5 dated May 28, 2008 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 May 30, 2008).
3.7	—	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).
3.8	—	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).
3.9	—	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed August 7, 2008).
3.10	—	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.11	—	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	—	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
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, 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, 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 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 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 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.9	—	Eighth Supplemental Indenture dated August 25, 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 August 25, 2006).
4.10	—	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 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).

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4.11	—	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 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 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	—	Twelfth Supplemental Indenture dated January 1, 2008 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 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.14	—	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 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 April 23, 2008).
4.15	—	Fourteenth Supplemental Indenture dated July 1, 2008 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 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.16	—	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the $7^{1}/8$% 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).
4.17	—	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P.'s Current Report on Form 8-K filed March 9, 2005).
4.18	—	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.19	—	Third Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a 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).
4.20	—	Fourth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.23 to the Annual Report on Form 10-K for the year ended December 31, 2007).

4.21†	—	Fifth Supplemental Indenture dated December 17, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee.
4.22	—	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a 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).
4.23	—	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a 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).
4.24	—	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
10.1	—	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).
10.2	—	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).
10.3	—	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).
10.4	—	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).
10.5	—	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).
10.6	—	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).
10.7**	—	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).

10.8**	—	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).
10.9**	—	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).
10.10**	—	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).
10.11**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.12**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13	—	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).
10.14	—	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).
10.15	—	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).
10.16	—	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).
10.17	—	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).
10.18**	—	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).
10.19**	—	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).
10.20**	—	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).
10.21**†	—	Directors' Compensation Summary.

10.22	—	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).
10.23**	—	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).
10.24**	—	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).
10.25**	—	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).
10.26**	—	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).
10.27**	—	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).
10.28**	—	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).
10.29	—	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).
10.30	—	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).
10.31	—	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).
10.32**	—	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).
10.33**	—	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).
10.34	—	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).
10.35	—	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).
10.36**	—	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).
10.37**	—	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).

10.38	—	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).
10.39**	—	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).
10.40**	—	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).
10.41**	—	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).
10.42	—	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).
10.43**	—	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).
10.44**	—	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).
10.45	—	Second Restated Credit Agreement dated as of November 6, 2008 by among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party there to (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 7, 2008).
10.46	—	Restated Guaranty Agreement dated November 6, 2008 by Plains All American Pipeline, L.P. 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 7, 2008).
10.47	—	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 on Form 8-K filed January 4, 2008).
10.48	—	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 (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2007).
10.49**†	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong.
10.50**†	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis.
10.51**†	—	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008.
10.52**†	—	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008.

10.53**†	—	Form of Amendment to LTIP grant letters dated December 4, 2008 (executive officers).
10.54**†	—	Form of Amendment to LTIP grant letters (directors).
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

Exhibit 4.21

EXECUTION COPY

This **FIFTH SUPPLEMENTAL INDENTURE** (this "Supplemental Indenture"), dated as of December 17, 2008, is among Plains All American Pipeline, L.P., a Delaware limited partnership ("Plains"), PAA Finance Corp., a Delaware corporation formerly known as Pacific Energy Finance Corporation ("Finance Corp"), each of the parties identified under the caption "Subsidiary Guarantors" on the signature pages hereof (the "Guarantors") and Wells Fargo Bank, National Association, a national association, as Trustee.

RECITALS

WHEREAS, Pacific Energy Partners, L.P., a Delaware limited partnership ("Pacific Energy"), Pacific Energy Finance Corporation, the initial Guarantors and the Trustee entered into an Indenture, dated as of June 16, 2004 (the "Indenture"), pursuant to which Pacific Energy and Pacific Energy Finance Corporation co-issued $250 million in aggregate principal amount of 7 1/8% Senior Notes due 2014 (the "Notes"), all of which are currently outstanding;

WHEREAS, Pacific Energy, Pacific Energy Finance Corporation, the initial Guarantors and the Trustee entered into a First Supplemental Indenture, dated as of March 3, 2005;

WHEREAS, Pacific Energy, Pacific Energy Finance Corporation, the initial Guarantors, Pacific Atlantic Terminals LLC and the Trustee entered into a Second Supplemental Indenture, dated as of September 23, 2005, in order to add Pacific Atlantic Terminals LLC as a Guarantor;

WHEREAS, Pacific Energy merged with and into Plains on November 15, 2006, with Plains being the survivor of such merger, and in that connection Plains, Pacific Energy Finance Corporation, the Guarantors named therein and the Trustee entered into the Third Supplemental Indenture pursuant to which, among other things, Plains unconditionally assumed all of the obligations of Pacific Energy under the Indenture and under the Notes;

WHEREAS, Plains, Pacific Energy Finance Corporation and the Guarantors named therein entered into a Fourth Supplemental Indenture, dated as of January 1, 2008, in order to add such Guarantors to the Indenture;

WHEREAS, on July 1, 2008, Pacific Energy Finance Corporation merged with PAA Finance Corp., with Pacific Energy Finance Corporation being the survivor of such merger, and in that connection Pacific Energy Finance Corporation changed its corporate name to PAA Finance Corp.;

WHEREAS, Section 9.01(d) of the Indenture provides that Plains, Finance Corp, the Guarantors and the Trustee may amend or supplement the Indenture to make changes to conform the Indenture to the Offering Memorandum relating to the Notes, without the consent of the Holders of the Notes;

WHEREAS, Section 4.18 of the Indenture does not conform to the Offering Memorandum due to the failure of such Section to refer to Section 4.10 of the Indenture as being among those Sections of the Indenture that are subject to covenant termination, a fact made clear by the section of the Offering Memorandum captioned "Covenant Termination," excerpts from which Offering Memorandum are attached to this Supplemental Indenture as Exhibit A for ready reference; and

---

WHEREAS, all acts and things prescribed by the Indenture, by law and by the Certificate of Incorporation and the Bylaws (or comparable constituent documents) of Plains, Finance Corp, the Guarantors and of the Trustee necessary to make this Supplemental Indenture a valid instrument legally binding on Plains, Finance Corp, the Guarantors and the Trustee, in accordance with its terms, have been duly done and performed;

NOW, THEREFORE, in consideration of the above premises, Plains, Finance Corp, the Guarantors and the Trustee covenant and agree for the equal and proportionate benefit of the respective Holders of the Notes as follows:

ARTICLE I

Section 1.01. This Supplemental Indenture is supplemental to the Indenture and does and shall be deemed to form a part of, and shall be construed in connection with and as part of, the Indenture for any and all purposes.

Section 1.02. This Supplemental Indenture shall become effective immediately upon its execution and delivery by each of Plains, Finance Corp, the Guarantors and the Trustee.

ARTICLE II

Section 2.01. Section 4.18 of the Indenture is hereby amended by adding "4.10," immediately after the reference to "4.09," in clause (b) of the first sentence of Section 4.18.

ARTICLE III

Section 3.01. Except as specifically modified herein, the Indenture and the Notes are in all respects ratified and confirmed (*mutatis mutandis*) and shall remain in full force and effect in accordance with their terms with all capitalized terms used herein without definition having the same respective meanings ascribed to them as in the Indenture.

Section 3.02. Except as otherwise expressly provided herein, no duties, responsibilities or liabilities are assumed, or shall be construed to be assumed, by the Trustee by reason of this Supplemental Indenture. This Supplemental Indenture is executed and accepted by the Trustee subject to all the terms and conditions set forth in the Indenture with the same force and effect as if those terms and conditions were repeated at length herein and made applicable to the Trustee with respect hereto.

Section 3.03. The Trustee makes no representation as to the validity or sufficiency of this Supplemental Indenture.

Section 3.04. THIS SUPPLEMENTAL INDENTURE SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.

Section 3.05. The parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of such executed copies together shall represent the same agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed as of the date first above written.

ISSUERS:

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/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

PAA FINANCE CORP.
(f/k/a Pacific Energy Finance Corporation)

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

SUBSIDIARY GUARANTORS:

PLAINS MARKETING GP INC.

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

[*Signature Page to Fifth Supplemental Indenture*]

PLAINS MARKETING, L.P.

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

PLAINS PIPELINE, L.P.

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

PACIFIC ENERGY GROUP, LLC

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

PACIFIC LA MARINE TERMINAL LLC

By: PACIFIC ENERGY GROUP LLC
its Sole Member

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

[*Signature Page to Fifth Supplemental Indenture*]

ROCKY MOUNTAIN PIPELINE SYSTEM LLC

By: PACIFIC ENERGY GROUP LLC
its Sole Member

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

PACIFIC ATLANTIC TERMINALS LLC

By: PACIFIC ENERGY GROUP LLC
its Sole Member

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

[*Signature Page to Fifth Supplemental Indenture*]

PLAINS MARKETING CANADA LLC

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson

Name: Al Swanson
Title: Senior Vice President and
Chief Financial Officer

PMC (NOVA SCOTIA) COMPANY

By: /s/ Al Swanson
Name: Al Swanson
Title: Vice President – Finance

PLAINS MARKETING CANADA, L.P.

By: PMC (NOVA SCOTIA) COMPANY
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Vice President – Finance

[*Signature Page to Fifth Supplemental Indenture*]

PLAINS LPG SERVICES GP LLC

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and
Chief Financial Officer

PLAINS TOWING LLC

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and
Chief Financial Officer

PICSCO LLC

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and
Chief Financial Officer

[*Signature Page to Fifth Supplemental Indenture*]

PLAINS MIDSTREAM GP LLC

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

PLAINS MIDSTREAM, L.P.

By: PLAINS MIDSTREAM GP LLC
its General Partner

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

PLAINS MIDSTREAM CANADA ULC

By: /s/ Al Swanson
Name: Al Swanson
Title: Vice President – Finance

[***Signature Page to Fifth Supplemental Indenture***]

AURORA PIPELINE COMPANY LTD.

By: /s/ Al Swanson
Name: Al Swanson
Title: Vice President – Finance

PLAINS LPG SERVICES, L.P.

By: PLAINS LPG SERVICES GP LLC
its General Partner

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and Chief Financial Officer

BASIN HOLDINGS GP LLC

By: PLAINS PIPELINE, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and
Chief Financial Officer

[*Signature Page to Fifth Supplemental Indenture*]

BASIN PIPELINE HOLDINGS, L.P.

By: BASIN HOLDINGS GP LLC
its General Partner

By: PLAINS PIPELINE, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and
Chief Financial Officer

RANCHO LPG HOLDINGS LLC

By: PLAINS LPG SERVICES, L.P.
its Sole Member

By: PLAINS LPG SERVICES GP, LLC
its General Partner

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President and
Chief Financial Officer

[*Signature Page to Fifth Supplemental Indenture*]

LONE STAR TRUCKING, LLC

By: PLAINS LPG SERVICES, L.P.
its Sole Member

By: PLAINS LPG SERVICES GP LLC
its General Partner

By: PLAINS MARKETING, L.P.
its Sole Member

By: PLAINS MARKETING GP INC.
its General Partner

By: /s/ Al Swanson
Name: Al Swanson
Title: Senior Vice President &
Chief Financial Officer

<u>TRUSTEE</u>:

WELLS FARGO BANK NATIONAL ASSOCIATION,
as Trustee

By: /s/ Maddy Hall
Name: Maddy Hall
Title: Vice President

[*Signature Page to Fifth Supplemental Indenture*]

EXHIBIT 10.21

Director Compensation Summary

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. During 2008, Messrs. Capobianco, Goyanes and Smith served as chairmen of the compensation, audit and governance committees, respectively.

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). Upon any vesting (other than the incremental audit committee awards), a cash payment is made to Vulcan Capital as directed by the Vulcan designee and to an affiliate of EnCap as directed by Mr. Petersen. Such cash payment is based on the unit value of Mr. Sinnott's award on the previous year's vesting date.

All LTIP awards held by a director vest in full upon the next following 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.

FIRST AMENDMENT TO
AMENDED AND RESTATED EMPLOYMENT AGREEMENT
Greg L. Armstrong

This First Amendment to Amended and Restated Employment Agreement (the "Amendment") is made as of the 4th day of December between Plains All American GP LLC, a Delaware limited liability company (the "Company") and Greg L. Armstrong ("Employee").

WHEREAS, on June 30, 2001, the Company and Employee entered into that certain Amended and Restated Employment Agreement (the "Agreement"); and

WHEREAS, the Company and Employee desire to amend the Agreement to comply with certain provisions of Section 409A of the Internal Revenue Code of 1986, as amended;

NOW THEREFORE, in consideration of the premises and mutual covenants and agreements contained herein and in the Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Company and Employee do hereby agree as follows:

1. Section 7(f) of the Agreement is hereby amended by adding the following sentence at the end thereof:

"As used in this Agreement, a termination of the Employee's employment means a "separation from service," for purposes of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code")."

2. Section 8(a) of the Agreement is hereby amended by adding the following sentence at the end thereof:

"Such death benefit shall be paid as soon as reasonably practical and in all events by the end of the year of the Employee's death or, if later, within 2½ months following his date of death."

3. Section 8(b) of the Agreement is hereby amended to read in full as follows:

"(b) During any period that the Employee fails to perform his duties hereunder as a result of disability (as defined in Section 409A of the Code) the Employee shall continue to receive his full Base Salary at the rate then in effect prior to the date of such disability until the Date of Termination if the Employee's employment is terminated pursuant to Section 7(b) hereof."

4. Section 8(g) of the Agreement is hereby amended by adding the following sentence at the end thereof:

"In all events, the Company's reimbursement of the Employee for payment of such excise tax shall be made as soon as practicable following its payment and in no event later than ten days following the date the Employee remits such excise tax to the proper governmental agency."

5. Section 9(a) of the Agreement is hereby amended by replacing the second sentence thereof with the following:

"Failure of the Company to obtain such agreement prior to the effectiveness of any such succession shall be a breach of this Agreement and shall constitute a Good Reason event under Section 7(d)."

6. Other than as amended hereby, the Agreement remains in full force and effect.

IN WITNESS WHEREOF, the parties have executed this Amendment as of the date first written above.

COMPANY:

PLAINS ALL AMERICAN GP LLC

By: /s/ Tim Moore
Name: Tim Moore
Title: Vice President

EMPLOYEE:

/s/ Greg L. Armstrong
Greg L. Armstrong

FIRST AMENDMENT TO
AMENDED AND RESTATED EMPLOYMENT AGREEMENT
Harry N. Pefanis

This First Amendment to Amended and Restated Employment Agreement (the "Amendment") is made as of the 4th day of December between Plains All American GP LLC, a Delaware limited liability company (the "Company") and Harry N. Pefanis ("Employee").

WHEREAS, on June 30, 2001, the Company and Employee entered into that certain Amended and Restated Employment Agreement (the "Agreement"); and

WHEREAS, the Company and Employee desire to amend the Agreement to comply with certain provisions of Section 409A of the Internal Revenue Code of 1986, as amended;

NOW THEREFORE, in consideration of the premises and mutual covenants and agreements contained herein and in the Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Company and Employee do hereby agree as follows:

1. Section 7(f) of the Agreement is hereby amended by adding the following sentence at the end thereof:

"As used in this Agreement, a termination of the Employee's employment means a "separation from service," for purposes of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code")."

2. Section 8(a) of the Agreement is hereby amended by adding the following sentence at the end thereof:

"Such death benefit shall be paid as soon as reasonably practical and in all events by the end of the year of the Employee's death or, if later, within 2½ months following his date of death."

3. Section 8(b) of the Agreement is hereby amended to read in full as follows:

"(b) During any period that the Employee fails to perform his duties hereunder as a result of disability (as defined in Section 409A of the Code) the Employee shall continue to receive his full Base Salary at the rate then in effect prior to the date of such disability until the Date of Termination if the Employee's employment is terminated pursuant to Section 7(b) hereof."

4. Section 8(g) of the Agreement is hereby amended by adding the following sentence at the end thereof:

"In all events, the Company's reimbursement of the Employee for payment of such excise tax shall be made as soon as practicable following its payment and in no event later than ten days following the date the Employee remits such excise tax to the proper governmental agency."

5. Section 9(a) of the Agreement is hereby amended by replacing the second sentence thereof with the following:

"Failure of the Company to obtain such agreement prior to the effectiveness of any such succession shall be a breach of this Agreement and shall constitute a Good Reason event under Section 7(d)."

6. Other than as amended hereby, the Agreement remains in full force and effect.

IN WITNESS WHEREOF, the parties have executed this Amendment as of the date first written above.

COMPANY:

PLAINS ALL AMERICAN GP LLC

By: /s/ Tim Moore
Name: Tim Moore
Title: Vice President

EMPLOYEE:

/s/ Harry N. Pefanis
Harry N. Pefanis

Exhibit 10.51

FIRST AMENDMENT TO
PLAINS ALL AMERICAN
2005 LONG-TERM INCENTIVE PLAN

December 4, 2008

By resolution of the Compensation Committee of the Board of Directors of Plains All American GP LLC, the Plains All American 2005 Long-Term Incentive Plan (the "Plan") is hereby amended as follows:

1. Section 8(m) of the Plan is hereby amended by adding the following language to the end thereof:

It is the intent that each Award under this Plan shall either (i) qualify as a "short term deferral" as such phrase is used in Section 409A of the Code or (ii) comply with the requirements of Section 409A. In that regard, notwithstanding anything in any Award to the contrary, (i) in no event shall payment of or under an Award be made later than 2½ months following the year in which such payment ceases to be subject to a substantial risk of forfeiture for purposes of Section 409A; (ii) for any Award in which all or a portion becomes "nonforfeitable" upon the occurrence of an event, the relevant provisions of such Award shall be deemed to include a proviso that (i) to the extent all requirements for vesting but for the passage of time have been met as of the occurrence of such event, payment shall be made as of the next following Distribution Date and (ii) to the extent additional vesting would require the achievement of additional performance thresholds (e.g. distribution or earnings levels), vesting shall occur and payment made (if based on a distribution) on the Distribution Date on which the threshold is achieved or (if based on earnings or other performance metric) the next Distribution Date following the date on which the threshold is achieved. For this purpose, as used herein and in any Award, the phrase "Distribution Date" shall mean the day in February, May, August or November in any year (as such month and year are specified in the Award or as context dictates; e.g., the "next following Distribution Date" after the occurrence of an event) that is 45 days after the end of a calendar quarter (or, if not a business day, the closest previous business day).

Exhibit 10.52

**SECOND AMENDMENT TO
PLAINS ALL AMERICAN GP LLC
1998 LONG-TERM INCENTIVE PLAN**

December 4, 2008

By resolution of the Compensation Committee of the Board of Directors of Plains All American GP LLC, the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "Plan") is hereby amended as follows:

1. Section 8 of the Plan is hereby amended by adding the following subsection (j) at the end thereof:

(j) Section 409A. It is the intent that each Award under this Plan shall either (i) qualify as a "short term deferral" as such phrase is used in Section 409A of the Code or (ii) comply with the requirements of Section 409A. In that regard, notwithstanding anything in any Award to the contrary, (i) in no event shall payment of or under an Award be made later than 2½ months following the year in which such payment ceases to be subject to a substantial risk of forfeiture for purposes of Section 409A; (ii) for any Award in which all or a portion becomes "nonforfeitable" upon the occurrence of an event, the relevant provisions of such Award shall be deemed to include a proviso that (i) to the extent all requirements for vesting but for the passage of time have been met as of the occurrence of such event, payment shall be made as of the next following Distribution Date and (ii) to the extent additional vesting would require the achievement of additional performance thresholds (e.g. distribution or earnings levels), vesting shall occur and payment made (if based on a distribution) on the Distribution Date on which the threshold is achieved or (if based on earnings or other performance metric) the next Distribution Date following the date on which the threshold is achieved. For this purpose, as used herein and in any Award, the phrase "Distribution Date" shall mean the day in February, May, August or November in any year (as such month and year are specified in the Award or as context dictates; e.g., the "next following Distribution Date" after the occurrence of an event) that is 45 days after the end of a calendar quarter (or, if not a business day, the closest previous business day).

December 8, 2008

«FirstName» «MI» «LastName»
«Street1»
«City» «State» «Zip»

Re: Amendments to Long-Term Incentive Plans and Awards

Dear «Salutation»:

The purpose of this letter is to notify you of and explain certain amendments that will apply to all outstanding Awards under the 1998 Long Term Incentive Plan, the 2005 Long Term Incentive Plan (including the PPX Legacy Plan) and the 2006 Tracking Unit Plan (as they may be amended from time to time, the "Long-Term Incentive Plans"). The relevant provisions deal with vesting of your Awards in the event of the termination of your employment because of your death or disability (which, if applicable, is defined in the grant letter for your Awards). These amendments are intended to avoid unintended and adverse tax consequences to you (including acceleration of the taxability of income into a year prior to actual receipt, plus a 20% penalty) that might otherwise result under Section 409A of the Internal Revenue Code.

Our records indicate that your Awards also include a "change of control" provision, which also requires amendment to assure compliance with Section 409A. This letter constitutes an amendment to any existing grant agreement evidencing Awards to you under the Long-Term Incentive Plans.

As currently drafted, your grant agreement would accelerate vesting if a change of control occurs, but only if accompanied by a "change in status." This amendment changes the definition of the phrase "change in status." The new definition (set forth in numbered paragraph 2 below) generally provides that a change in status occurs only if (i) the Company terminates your employment other than for Cause or (ii) you terminate employment for any of the reasons stated. The basic change in the definition is in the second part. The current definition does not require actual termination of employment by you for the accelerated vesting to occur. Also, the current definition includes a material change in fringe benefits as an acceleration event, which is not included in the amended definition.

Your Awards are amended, effective as of December 4, 2008, as follows:

1. The following language is hereby added to each Long-Term Incentive Plan and to each Award outstanding thereunder:

It is the intent that each Award under this Plan shall either (i) qualify as a "short term deferral" as such phrase is used in Section 409A of the Code or (ii) comply with the requirements of Section 409A. In that regard, notwithstanding anything in any Award to the contrary, (i) in no event shall payment of or under an Award be made later than 2½ months following the year in which such payment ceases to be subject to a substantial risk of forfeiture for purposes of Section 409A; (ii) for any Award in which all or a portion becomes "nonforfeitable" upon the occurrence of an event, the relevant provisions of such Award shall be deemed to include a proviso that (i) to the extent all requirements for vesting but for the passage of time have been met as of the occurrence of such event, payment shall be made as of the next following Distribution Date and (ii) to the extent additional vesting would require the achievement of additional performance thresholds (e.g. distribution or earnings levels), vesting shall occur and payment made (if based on a distribution) on the Distribution Date on which the threshold is achieved or (if based on earnings or other performance metric) the next Distribution Date following the date on which the threshold is achieved. For this purpose, as used herein and in any Award, the phrase "Distribution Date" shall mean the day in February, May, August or November in any year (as such month and year are specified in the Award or as context dictates; e.g., the "next following Distribution Date" after the occurrence of an event) that is 45 days after the end of a calendar quarter (or, if not a business day, the closest previous business day).

2. The definition of "Change in Status" applicable to your Awards is hereby amended to read in full as follows:

The phrase "Change in Status" means (A) the termination of your employment by the Company other than a Termination for Cause, within two and a half months prior to or one year following a Change of Control (the "Protected Period"), or (B) the termination of your employment by you due to the occurrence during the Protected Period, without your written consent, of (i) any material diminution in your authority, duties or responsibilities, (ii) any material reduction in your base salary or (iii) any other action or inaction that constitutes a material breach of the Agreement by the Company. A termination by you shall not be a Change in Status unless (1) you provide written notice to the Company of the condition in (B)(i), (B (ii) or (B)(iii) that would constitute a change in status within 90 days of the initial existence of the condition and (2) the Company fails to remedy the condition within the 30-day period following such notice. As used herein, a termination of the Employee's employment means a "separation from service," for purposes of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code").

If you have any questions regarding these changes, please contact me at extension 4484. **To assure the desired effect for purposes of Section 409A, you must sign and return the enclosed copy of this letter to me no later than December 31, 2008.**

Very truly yours,

PLAINS ALL AMERICAN GP LLC

By: /s/ Tim Moore
Name: Tim Moore
Title: Vice President, General Counsel and Secretary

ACKNOWLEDGED AND AGREED:

____
«FirstName» «MI» «LastName»

Date: __________________________

PLAINS ALL AMERICAN

December 8, 2008

Name of Director LTIP grantee
Address
City, State Zip

Re: Amendment to Long-Term Incentive Plans and Awards

Dear [name]:

As you will recall, at the November Board meeting, the Board authorized the Compensation Committee to take action with respect to amendment of compensation arrangements to comply with Section 409A of the Internal Revenue Code. The Committee met on December 4, 2008, and determined to amend the Long-Term Incentive Plans and certain Awards thereunder. The Awards to be amended include those granted to you as a Director. The relevant provisions deal with vesting of your Awards in the event of the termination of your term because of your death, disability or retirement (which, if applicable, is defined in the grant letter for your Awards).

This letter constitutes an amendment to any existing grant agreement evidencing Awards to you under the Long-Term Incentive Plans. This amendment is intended to avoid unintended and adverse tax consequences to you (including acceleration of the taxability of income into a year prior to actual receipt, plus a 20% penalty) that might otherwise result.

In that regard, your existing grant agreement evidencing Awards under the Long-Term Incentive Plans is hereby amended, effective as of December 4, 2008, as follows:

1. Each reference to *"next vesting date"* is replaced with *"next following Distribution Date."*

2. The definition of "Distribution Date" is hereby amended to read in full as follows:

"The phrase "Distribution Date" shall mean the day in February, May, August or November that is 45 days after the end of a calendar quarter (or, if not a business day, the closest previous business day)."

Further, each Long-Term Incentive Plan is amended by adding the following language thereto:

"It is the intent that each Award under this Plan shall either (i) qualify as a "short term deferral" as such phrase is used in Section 409A of the Code or (ii) comply with the requirements of Section 409A. In that regard, notwithstanding anything in any Award to the contrary, (i) in no event shall payment of or under an Award be made later than 2½ months following the year in which such payment ceases to be subject to a substantial risk of forfeiture for purposes of Section 409A; (ii) for any Award in which all or a portion becomes "nonforfeitable" upon the occurrence of an event, the relevant provisions of such Award shall be deemed to include a proviso that (i) to the extent all requirements for vesting but for the passage of time have been met as of the occurrence of such event, payment shall be made as of the next following Distribution Date and (ii) to the extent additional vesting would require the achievement of additional performance thresholds (e.g. distribution or earnings levels), vesting shall occur and payment made (if based on a distribution) on the Distribution Date on which the threshold is achieved or (if based on earnings or other performance metric) the next Distribution Date following the date on which the threshold is achieved. For this purpose, as used herein and in any Award, the phrase "Distribution Date" shall mean the day in February, May, August or November in any year (as such month and year are specified in the Award or as context dictates; e.g., the "next following Distribution Date" after the occurrence of an event) that is 45 days after the end of a calendar quarter (or, if not a business day, the closest previous business day)."

If you have any questions regarding these changes, please contact me at extension 4484.

Very truly yours,

PLAINS ALL AMERICAN GP LLC

By: /s/ Tim Moore
Name: Tim Moore
Title: Vice President, General Counsel and Secretary

Exhibit 21.1

SUBSIDIARIES OF
PLAINS ALL AMERICAN PIPELINE, L.P.
(*As of 12/31/08*)

Subsidiary	Jurisdiction of Organization
PAA Finance Corp.	Delaware
Plains Marketing, L.P.	Texas
Plains Pipeline, L.P.	Texas
Plains Marketing GP Inc.	Delaware
Plains Marketing Canada LLC	Delaware
Plains Marketing Canada, L.P.	Canada
PMC (Nova Scotia) Company	Nova Scotia
Basin Holdings GP LLC	Delaware
Basin Pipeline Holdings, L.P.	Delaware
Rancho LPG Holdings LLC	Delaware
Plains LPG Services GP LLC	Delaware
Plains LPG Services, L.P.	Delaware
PICSCO LLC	Delaware
Lone Star Trucking, LLC	California
Plains Towing LLC	Delaware
Pacific Energy GP, LP	Delaware
Pacific Energy Management LLC	Delaware
Pacific Energy Group LLC	Delaware
Pacific Pipeline System LLC	Delaware
Pacific Terminals LLC	Delaware
Pacific LA Marine Terminal LLC	Delaware
Rocky Mountain Pipeline System LLC	Delaware
SLC Pipeline LLC	Delaware
Pacific Atlantic Terminals LLC	Delaware
PEG Canada GP LLC	Delaware
Aurora Pipeline Company	Canada
Plains Midstream GP LLC	Delaware
Plains Midstream, L.P.	Delaware
Plains Midstream Canada ULC	Alberta

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-138888, 333-155671 and 333-155673) and on Form S-8 (No. 333-91141, 333-54118, 333-74920, 333-122806, and 333-141185) of Plains All American Pipeline, L.P. of our report dated February 26, 2009 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP
Houston, Texas
February 26, 2009

EXHIBIT 31.1

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

I, Greg L. Armstrong, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 26, 2009

/s/ Greg L. Armstrong
Greg L. Armstrong
Chief Executive Officer

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

I, Al Swanson, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 26, 2009

/s/ Al Swanson
Al Swanson
Chief Financial Officer

EXHIBIT 32.1

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

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

(i) the accompanying report on Form 10-K for the period ended December 31, 2008 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

/s/ Greg L. Armstrong
Name: Greg L. Armstrong
Date: February 26, 2009

EXHIBIT 32.2

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

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

(i) the accompanying report on Form 10-K for the period ended December 31, 2008 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

/s/ Al Swanson
Name: Al Swanson
Date: February 26, 2009