

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 and unless the context indicates otherwise, the terms “Partnership,” “Plains,” “we,” “us,” “our,” “ours” and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries.

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.” We are also engaged in the development and operation of natural gas storage facilities.

Our business activities are conducted through three segments: Transportation, Facilities and Supply and Logistics. We previously referred to the Supply and Logistics segment as the Marketing segment. We revised the segment name to better describe the business activities conducted within that segment.

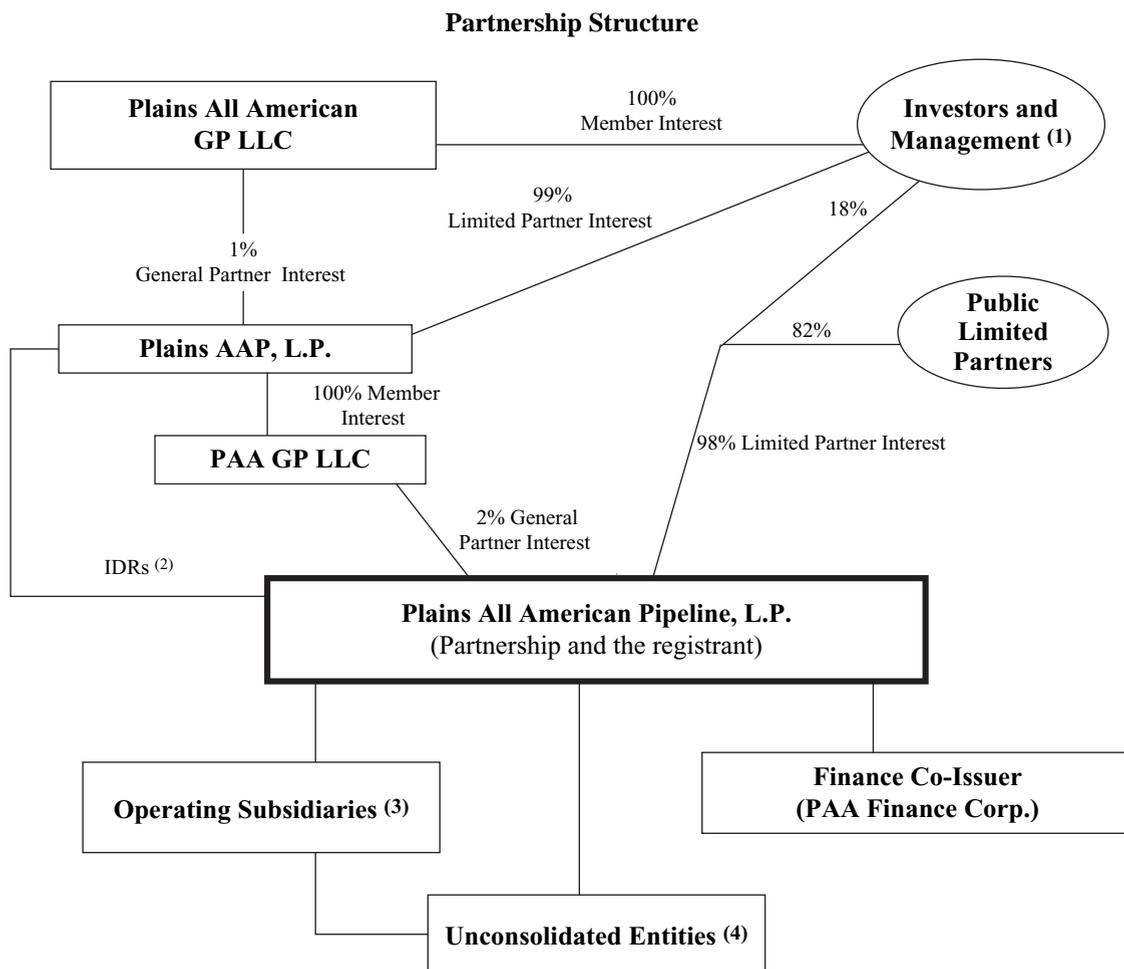
Organizational History

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 13 holders, with four of these holders owning an aggregate interest of 95%. 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.



- (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 18% 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 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., PAA Natural Gas Storage, LLC (“PNGS”) and Plains Midstream Canada ULC.
- (4) The Partnership holds direct and indirect equity interests in unconsolidated entities including Settoon Towing, LLC (“Settoon Towing”), Butte Pipe Line Company (“Butte”) and Frontier Pipeline Company (“Frontier”).

Business Strategy

Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage and supply and logistics 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, LPG and natural gas storage in the United States and Canada by combining the strategic location and capabilities of our transportation, terminalling and storage assets with our extensive supply, logistics 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 terminals and leased assets to optimize our presence in the waterborne importation of foreign crude oil;
- capitalizing on the anticipated long-term growth in demand for natural gas storage services in North America by owning and operating high-quality natural gas storage facilities and providing our current and future customers reliable, competitive and flexible natural gas storage and related services;
- selectively pursuing strategic and accretive acquisitions of crude oil, refined products and LPG transportation, terminalling, storage and supply and logistics assets and businesses that complement our existing asset base and distribution capabilities; and
- using our terminalling and storage assets in conjunction with our supply and logistics activities to capitalize on inefficient energy markets and to address physical market imbalances, mitigate inherent risks and increase margin.

We believe PNGS's natural gas storage assets are also well-positioned to benefit from long-term industry trends and opportunities. PNGS's growth strategies are to develop and implement internal growth projects and to selectively pursue strategic and accretive natural gas storage projects and facilities. Through execution of such growth strategies, we intend to expand the scale and scope of our natural gas storage business. 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);
- an average total debt-to-total capitalization ratio of approximately 60%; and
- an average adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

The first two of these four metrics include long-term debt as a critical measure. In certain market conditions, we also incur short-term debt in connection with supply and logistics activities that involve the simultaneous purchase and forward sale of crude oil, refined products and LPG. The crude oil, refined products and LPG purchased in these transactions are hedged. We do not consider the working capital borrowings associated with this activity to be part of our long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds. We also incur short-term debt for New York Mercantile Exchange ("NYMEX") and IntercontinentalExchange ("ICE") margin requirements.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund at least 50% of the capital requirements associated with these activities with equity and cash

flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile as, in certain cases, these capital expenditures and acquisitions may be financed initially using debt or there may be delays in realizing anticipated synergies from acquisitions or contributions from capital expansion projects to adjusted EBITDA.

Credit Rating

As of February 2010, our senior unsecured ratings with Standard & Poor's Ratings Services and Moody's Investors Service 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, 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 supply and logistics activities are counter-cyclically balanced.* We believe the variety of activities executed within our supply and logistics 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.
- *Natural gas storage provides diversifying growth to fee-based business.* This business is underpinned by long term capacity contracts serviced by two facilities including the Pine Prairie facility. Expansion activity at the Pine Prairie facility will enable us to benefit from anticipated long-term growth in demand for natural gas storage capacity in North America.
- *We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Over the past twelve years, we have completed and integrated 59 acquisitions with an aggregate purchase price of approximately \$6.4 billion. We have also implemented internal expansion capital projects totaling approximately \$2.1 billion. In addition, we believe we have resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2009, we had approximately \$950 million 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 25 years industry experience, and an average of 16 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.

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.

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

<u>Acquisition</u>	<u>Date</u>	<u>Description</u>	<u>Approximate Purchase Price</u>
Southcap Pipe Line Co. ("Southcap")	Dec-2009	An additional 21% undivided joint interest in the Capline Pipeline System ("Capline") and additional tankage ⁽¹⁾	\$ 62
PAA Natural Gas Storage, LLC.....	Sep-2009	Remaining 50% interest in PNGS	\$ 215 ⁽²⁾
Rainbow Pipeline Company ("Rainbow").....	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	60% 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") ⁽³⁾	\$ 130
Andrews Petroleum and Lone Star Trucking ("Andrews").....	Apr-2006	Isomerization, fractionation, marketing and transportation services	\$ 220
South Louisiana Gathering and Transportation Assets	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	50% interest in PNGS	\$ 125

⁽¹⁾We acquired our initial 22% undivided joint interest in the Capline Pipeline System in March 2004.

⁽²⁾ In connection with the PNGS acquisition we consolidated and subsequently refinanced approximately \$450 million of previously non-recourse joint venture debt. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.

⁽³⁾ We relinquished our interest in HIPS in November 2006.

2009 Acquisitions

PNGS Acquisition

On September 3, 2009, we acquired the remaining 50% indirect interest in PNGS for an aggregate purchase price of \$215 million (“PNGS Acquisition”). See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition. As a result of the transaction, we now own 100% of PNGS’s natural gas storage business and related operating entities, which are accounted for on a consolidated basis beginning in September 2009. We historically accounted for our 50% indirect interest in PNGS under the equity method. We recorded a net gain of approximately \$9 million, recorded in other income, in connection with (i) adjusting our previously owned 50% investment in PNGS to fair value and (ii) terminating an agreement to supply natural gas to PNGS.

PNGS currently owns and operates two natural gas storage facilities located in Louisiana and Michigan that have an aggregate working gas storage capacity of 40 billion cubic feet (“Bcf”) and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. PNGS also leases storage capacity and pipeline transportation capacity from third parties from time to time in order to increase its operational flexibility and enhance the services it offers its customers. As of December 31, 2009, PNGS had 3 Bcf of storage capacity under lease from third parties and had secured the right to 379 MMcf per day of firm transportation service on various pipelines. Substantially all of PNGS’s revenues are derived from the provision of firm storage services under multi-year, fee-based contracts. The gas storage operations are reflected in our facilities segment.

Other Acquisitions

During 2009, we completed six additional acquisitions for aggregate consideration of approximately \$178 million. These included an additional 21% undivided joint interest in Capline and associated tankage, as well as various crude oil pipelines and pipeline systems that are all included within our transportation segment. We also acquired a natural gas processing business, a refined products terminal and various crude oil storage tanks and other related assets that are all included within our facilities segment. The goodwill associated with such acquisitions was approximately \$24 million. Please read Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Internal Growth Projects—Acquisitions” and see Note 3 to our Consolidated Financial Statements for further discussion of our acquisitions.

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, LPG and natural gas storage related 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 11% of the world's petroleum production, but consumes 22% 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).

	2009 ⁽¹⁾	Projected		
		2010	2011	2015
(In millions of barrels per day)				
Supply				
OECD ⁽²⁾				
U.S.	9.0	9.1	9.4	10.0
Other	11.9	11.9	11.5	11.3
Total OECD	20.9	21.0	20.9	21.3
Organization of the Petroleum Exporting Countries				
Countries	34.0	34.1	35.7	37.5
Other	29.3	30.8	30.6	32.2
Total World Production	84.2	85.9	87.2	91.0
Demand				
OECD				
U.S.	18.7	19.2	19.8	20.2
Other	26.7	27.2	27.2	27.5
Total OECD	45.4	46.4	47.0	47.7
Other	38.7	39.5	40.2	43.2
Total World Consumption	84.1	85.9	87.2	90.9
Net World Production/(Consumption).....	0.1	—	—	0.1
U.S. Production as % of World Production ...	11%	11%	11%	11%
U.S. Consumption as % of World Consumption	22%	22%	23%	22%
Net U.S. Consumption	(9.7)	(10.1)	(10.4)	(10.2)

(1) The 2009 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. The challenging global economic climate has resulted in reduced demand and continued uncertainty in the petroleum market. To the extent that an event causes weaker world economic growth, energy demand would likely decline and result in lower energy prices, depending on the production responses of producers.

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 collectively 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. For the 20-year time period beginning in 1985 through 2004, U.S. refinery demand for crude oil increased 29% from 12.0 million barrels per day to approximately 15.5 million barrels per day. U.S. refinery demand for crude oil demand remained effectively flat from 2005 through 2007, after which refinery demand decreased to average approximately 14.5 million barrels per day for the 12 months ended October 2009. Of this amount, only 5.2 million barrels per day was produced domestically. Accordingly, approximately 64% of the crude oil used by U.S. domestic refineries is imported. This imbalance represents a continuing trend, with foreign imports of crude oil tripling over a 23-year period, from 3.2 million barrels per day in 1985 to approximately 10.1 million barrels per day from 2005-2007. Concurrent with decreased refinery demand, during 2008 and 2009 foreign crude imports slowed to 9.3 million barrels per day for the 12 months ended October 2009. 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 2009 column are based on the twelve months from November 2008 to October 2009.

	<u>Actual</u>	<u>Projected</u>		
	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2015</u>
	(In millions of barrels per day)			
Supply				
Domestic Crude Oil Production.....	5.2	5.3	5.4	5.8
Net Imports - Crude Oil.....	9.3	8.8	9.1	8.9
Crude Oil Input to Domestic Refineries.....	14.5	14.1	14.5	14.7
Net Product Imports.....	0.4	1.2	1.3	1.2
Other - (NGL Production, Refinery Processing Gain).....	3.8	3.9	4.0	4.3
Total Domestic Petroleum Consumption.....	<u>18.7</u>	<u>19.2</u>	<u>19.8</u>	<u>20.2</u>

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 2009 and is derived from information published by the EIA (see EIA website at www.eia.doe.gov) (in millions of barrels per day).

<u>Petroleum Administration Defense District</u>	<u>Regional Supply</u>	<u>Refinery Demand</u>	<u>Supply Shortfall</u>
PADD I (East Coast).....	0.0	1.3	(1.3)
PADD II (Midwest).....	0.6	3.2	(2.6)
PADD III (South).....	3.0	7.0	(4.0)
PADD IV (Rockies).....	0.3	0.5	(0.2)
PADD V (West Coast).....	1.3	2.4	(1.1)
Total U.S.....	<u>5.2</u>	<u>14.4</u>	<u>(9.2)</u>

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 24 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 600,000 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 2009. As a result, the volume of crude oil transported into PADD II has increased approximately 47% in absolute terms or 1.6% annually from 1.7 million barrels per day to 2.6 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 various aspects of the crude oil market including absolute price, market structure, grade and location differentials has increased over time and we expect this volatility 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;
- Regional supply and demand imbalances;
- Political instability in critical producing nations;
- Policy decisions made by various governments around the world attempting to navigate energy challenges; 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.

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: transportation 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 transportation fuels, particularly motor gasoline.

The characteristics of the gasoline produced depend upon the setup of the refinery at which it is produced. 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 a recent peak in 2005 of 20.8 million barrels, yielding an average annual increase of approximately 1.5%. Due to recent economic weakness, refined product demand has decreased to average approximately 18.7 million barrels per day for the twelve months ended October 2009. Given the decreased demand for refined products and resulting excess refining capacity, a number of U.S. refineries have reduced output and, in some cases, indefinitely closed. The EIA is currently forecasting growth in refined product demand to resume in 2010 and continue thereafter. We believe that this projected additional intermediate and long-term demand will be met primarily by increased utilization of available capacity as well as increased imports of refined products, the combination of which we believe will generate incremental demand for midstream infrastructure, including pipelines and terminals. We believe that demand for refined products pipeline and terminalling infrastructure will also be driven by the following factors:

- multiple specifications of existing products (also referred to as boutique gasoline blends);
- continued specification changes to existing products, such as lower sulfur limits; and
- increased acceptance and mandates of biofuels.

The complexity and volatility of the refined products market creates opportunities to solve the logistical inefficiencies inherent in the business.

LPG Products Market Overview

LPGs are hydrogen-based gases that are derived from crude oil refining and natural gas processing and include propane, butane and isobutane. 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 varying uses. For example, propane is 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 diluents 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;
- petro-chemical demand;
- diluent requirements 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.

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.

Drivers of Demand for Storage. The long-term demand for storage services in the United States is driven primarily by the long-term demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis. In general, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users (such as gas-fired power generators and residential and commercial consumers), demand for natural gas storage services should also grow. In addition, any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations, should increase the need for and value of storage services.

Natural Gas Demand. According to the EIA, during the period from 1998 through 2008, natural gas consumption increased by 4.1% overall from an average of approximately 60.9 Bcf per day in 1998 to an average of approximately 63.4 Bcf per day in 2008. Although the change in consumption levels during this period was variable on a year-to-year basis, growth was highest in the seasonal and weather-sensitive power generation and commercial/residential sectors, where consumption grew by approximately 45.2% and 6.2%, respectively. The growth in these sectors was partially offset by an approximate 20.5% decline in gas consumption in the less seasonal industrial sector.

Despite the increased use of natural-gas fired generation during the summer cooling months, the seasonality of natural gas consumption has remained strong. According to EIA data, during the last decade, consumption during the winter months averaged approximately 40% more than consumption during the summer months.

Natural Gas Supply. For the majority of the last decade, domestic production has been relatively flat and has failed to keep pace with domestic consumption. Over the past few years, however, domestic production has been growing, primarily due to increases in production from developing shale resource plays. According to EIA data during the two-year period from January 1, 2007 through December 31, 2008, domestic production of natural gas increased by an average of approximately 5% per year and estimates of proved natural gas reserves increased by an average of approximately 7.5% per

year, in each case largely due to continued development of shale resources. Beginning in 2007, leasing and development activities increased in a number of new shale resource plays, which in 2009 caused the EIA to significantly increase its outlook for domestic natural gas production. Notably, the typical production profile for shale production is short lived with initial high levels of production and steep declines thereafter. For this reason, and because producing gas from shale formations is generally more complex and expensive than conventional onshore production, it is difficult to predict future shale resource production levels with certainty.

In addition to the emergence of domestic shale plays as a significant supply source, over the past several years, the U.S. has developed significant infrastructure for the import of liquefied natural gas (“LNG”). In recent years, U.S. and Canadian LNG imports have averaged an aggregate of approximately 1 to 3 Bcf per day, while the total LNG import capacity of U.S. and Canadian infrastructure is approximately 16 Bcf per day. In addition, total worldwide liquefaction capacity for LNG has been increasing over the last several years and additional capacity is scheduled to come online over the next few years.

For the foreseeable future, we believe there will be ample supplies of natural gas from a combination of domestic production, pipeline imports and waterborne imports of LNG. We also believe, however, that it is difficult to predict the extent to which domestic production from shale resources and LNG imports will increase or decrease and that this “source of supply uncertainty” adds an element of volatility to natural gas markets that will drive greater demand for storage services, especially from well-positioned, high performance facilities that can provide customers with access to both LNG imports and shale production.

Description of Segments and Associated Assets

Our business activities are conducted through three segments—Transportation, Facilities and Supply and Logistics. 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 noncontrolling interests.

As of December 31, 2009, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 16,000 miles of active crude oil and refined products pipelines and gathering systems;
- 28 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 84 trucks and 353 trailers; and
- 68 transport and storage barges and 39 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, 2009, grouped by geographic location:

<u>Region / Pipeline and Gathering Systems</u> ⁽¹⁾	<u>System Miles</u>	<u>2009 Average Net Barrels per Day</u> ⁽²⁾ (in thousands)
<u>Southwest US</u>		
Basin	519	394
Other	3,601	484
Southwest US Subtotal	4,120	878
<u>Western US</u>		
All American	138	40
Line 63/Line 2000	428	131
Other	152	102
Western US Subtotal	718	273
<u>US Rocky Mountain</u>		
Salt Lake City Area Systems	708	131
Other	3,313	252
US Rocky Mountain Subtotal	4,021	383
<u>US Gulf Coast</u>		
Capline ⁽³⁾	632	193
Other	943	290
US Gulf Coast Subtotal	1,575	483
<u>Central US Subtotal</u>	2,546	362
Domestic Total	12,980	2,379
<u>Canada</u>		
Rangeland	1,252	53
Rainbow	594	183
Manito	554	63
Other	635	158
Canada Total	3,035	457
Grand Total	16,015	2,836

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

(2) Represents average volumes for the entire year of 2009.

(3) Non-operated pipeline.

Southwest US

Basin Pipeline System. We own an approximate 87% undivided joint interest in and act as operator of the Basin Pipeline system. The Basin system is a primary route for transporting crude oil from the Permian Basin (in west Texas and southern New Mexico) to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. The Basin system is a 519-mile mainline, telescoping crude oil system with a system 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 394,000 barrels per day (attributable to our interest) during 2009.

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 of tankage located along the system. The Basin system is subject to tariff rates regulated by the Federal Energy Regulatory Commission (“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 2009, 2008 and 2007, tariffs on the All American Pipeline averaged \$2.46 per barrel, \$2.24 per barrel and \$2.18 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 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,				
	2009	2008	2007	2006	2005
Average daily volumes received from:					
Point Arguello (at Gaviota).....	6	7	8	9	10
Santa Ynez (at Las Flores).....	34	38	38	40	41
Total.....	40	45	46	49	51

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.

During the fourth quarter of 2009, a 71-mile segment of Line 63 was temporarily taken out of service to allow for certain repairs and realignments to be performed. Line 63 volumes are currently being redirected from the north end of this out-of-service segment to the parallel Line 2000. The product is then batched along Line 2000 until it is re-injected into the active portion of Line 63, which is south of the out-of-service segment, for subsequent delivery to customers. This temporary pipeline segment closure and redirection of product has not impacted our normal throughput levels on this line. For 2009, combined throughput on Line 63 totaled an average of approximately 67,000 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 (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 2009, throughput on Line 2000 averaged approximately 64,000 barrels per day.

US Rocky Mountain

Salt Lake City Area Systems. We operate the Salt Lake City Area systems, in which we own between 75% and 100% interests. The Salt Lake City Area systems include interstate and intrastate common carrier crude oil pipeline systems that transport crude oil produced in Canada and the U.S. Rocky Mountain region to refiners in Salt Lake City, Utah and to other pipelines at Ft. Laramie, Wyoming. The Salt Lake City Area systems consist of 708 miles of pipelines (including the Wahsatch pipeline discussed below) and storage tanks with a total storage capacity of approximately 1 million barrels. The trunk pipeline originates at Wamsutter, Wyoming and receives deliveries from local trucks and gathering systems and can deliver to Salt Lake City, Utah and Ft. Laramie, Wyoming. The Salt Lake City Area systems have a combined throughput capacity of approximately 120,000 barrels per day to Salt Lake City and 20,000 barrels per day to Ft. Laramie.

During the fourth quarter of 2008, construction was completed on the 94-mile expansion of the Salt Lake City Area system from the terminus of Frontier Pipeline to Salt Lake City, which has throughput capacity of 120,000 barrels per day and is referred to as the Wahsatch pipeline. This line was placed into service in the first quarter of 2009. Ten-year transportation contracts have been executed with four Salt Lake City refiners for service on this pipeline. In the first quarter of 2009, we executed an agreement in which we sold a 25% interest in this line to Holly Energy Partners-Operating, L.P. As part of this agreement, Holly Refining and Marketing Company also entered into a 10-year transportation agreement making it the fifth refinery to commit. Plains' portion of the total project cost was approximately \$228 million. For 2009, throughput on the Salt Lake City Area Systems in total averaged approximately 131,000 barrels per day.

US Gulf Coast

Capline Pipeline System. The Capline Pipeline system is a 632-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. In December 2009, we purchased an additional 21% undivided interest in the Capline Pipeline System. The assets purchased also included a 100% interest in 720,000 barrels of tankage at Patoka, Illinois. We acquired our initial 22% interest in Capline in 2004, and as a result of this transaction, we now have an aggregate undivided joint interest of 43%.

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 through August 2013. 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 were attributable to our interest during 2009. In connection with the purchase of our additional undivided interest in the system, our attributable interest has increased to approximately 470,000 barrels per day. Throughput on our interest averaged approximately 193,000 barrels per day during 2009.

Canada

Rangeland System. We own a 100% interest in the Rangeland system, which includes the Mid Alberta Pipeline ("MAPL") and the Rangeland Pipeline. The Rangeland system consists of a 592 mile, 8-inch to 16-inch mainline pipeline and 660 miles of 3-inch to 8-inch gathering pipelines. Rangeland transports butane, condensate, light sweet crude and light sour crude either north to Edmonton, Alberta via third-party pipeline connections or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. 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. During 2009, we acquired the Valley and Cremona pipeline systems which are included in the 660 miles of gathering pipeline. These acquisitions expanded our gathering system in central Alberta and bring us closer to providing single pipeline access to the Edmonton market. During 2009, Plains built and commissioned 240,000 barrels of tankage bringing our storage capability at Edmonton to 320,000 barrels. Total average throughput during 2009 on the Rangeland system was approximately 53,000 barrels per day.

Rainbow System. We own a 100% interest in the Rainbow system. The Rainbow system consists of a 480-mile, 20-inch to 24-inch mainline crude oil pipeline extending from the Norman Wells Pipeline located in Zama, Alberta to Edmonton, Alberta and 114 miles of gathering pipelines. During 2009, we added a heavy oil truck terminal at Nipisi, Alberta to provide producers with additional access to Rainbow. The system has a throughput capacity of approximately 200,000 barrels per day and transported approximately 183,000 barrels per day during 2009.

Manito. We own a 100% interest in the Manito heavy oil system. This 554-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. The Manito pipeline includes 334 miles of pipeline, the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 136 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 2009, approximately 63,000 barrels per day of crude oil were transported on 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, LPG and natural gas, 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 storage capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil, refined products, LPG or natural gas from one connecting pipeline and redeliver the applicable product to another connecting carrier, (iii) hub service fees for the movement of natural gas across our header systems, and (iv) fees from LPG fractionation and isomerization services.

As of December 31, 2009, we owned, operated and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 51 million barrels of crude oil and refined products capacity primarily at our terminalling and storage locations;
- approximately 6 million barrels of LPG storage capacity;
- approximately 40 Bcf of natural gas storage capacity; and
- approximately 9 Bcf of base gas in storage facilities owned by us;
- 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.

As of December 31, 2009, we were in the process of constructing approximately 7 million barrels of additional above-ground crude oil and refined product terminalling and storage capacities and an additional 31 Bcf of high-deliverability salt-cavern natural gas storage capacity.

Following is a tabular presentation of our active facilities segment assets in the United States and Canada as of December 31, 2009, grouped by product type:

Facility	Capacity (in millions of barrels, except where noted)
Crude Oil and Refined Products	
<i>Cushing</i>	11
<i>Kerrobert</i>	1
<i>LA Basin</i>	10
<i>Martinez and Richmond</i>	5
<i>Mobile and Ten Mile</i>	3
<i>Patoka</i>	3
<i>Philadelphia Area</i>	4
<i>St. James</i>	6
<i>Other</i>	8
Subtotal	51
LPG	
<i>Bumstead</i>	2
<i>Tirzah</i>	1
<i>Other</i>	3
Subtotal	6
Natural Gas	
<i>Pine Prairie</i>	14 Bcf
<i>Bluewater/Kimball</i>	26 Bcf

The discussion below contains 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. See “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 2008, we commenced a project at the Kerrobert terminal, which provides receipt access to heavy oil from the Enbridge system and increases delivery capacity while reducing third-party costs. The cost of the project is estimated to be approximately \$42 million, of which approximately \$33 million was incurred in 2009. The total storage capacity at the Kerrobert terminal is approximately 1 million barrels.

L.A. Basin. We own five 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. Approximately 9 million barrels of the storage capacity are used for commercial service 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 have 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 has 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. Our Patoka Terminal has approximately 3 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. 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 "Crude Oil Storage Facilities Under Construction and Under Development" below for discussion of ongoing expansion activities at this facility.

Philadelphia Area Terminals. We own four refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have a combined storage capacity of approximately 4 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.

St. James Terminal. We have approximately 6 million barrels of crude oil storage capacity at the St. James crude oil interchange in Louisiana, which is one of the three most liquid crude oil interchanges in the United States. The facility also includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. During the fourth quarter of 2009, we also substantially completed construction of a marine dock that is able to receive both barges and tankers. We are currently able to receive barges and will bring the dock into full service for tankers during the first quarter of 2010. See "Crude Oil Storage Facilities Under Construction and Under Development" below for discussion of ongoing expansion activities at this facility.

Crude Oil Storage Facilities Under Construction and Under Development

Cushing Terminal & Mid-Continent Area. During 2009, we began construction on additional crude oil tankage at our Cushing Terminal. The project included the construction of approximately 2 million barrels of storage that is projected to be completed during 2010. This expansion is supported by long-term customer commitments. As of December 31, 2009, we have spent approximately \$25 million towards this project out of a total estimated cost of approximately \$42 million. In addition, late in 2009 we approved the construction of approximately 1 million barrels of storage capacity at our Cushing Terminal, which has an anticipated total cost of approximately \$18 million, and another approximately 1 million barrels of storage capacity at our Wichita Falls, Texas facility at a cost of approximately \$13 million. These expansions are expected to be completed in 2011 and are supported by long-term customer commitments.

Patoka & St. James Terminals and Dock. During 2009, we began construction on light-product storage tankage at the Patoka and St. James terminal locations. These projects will include the construction of 600,000 barrels of storage capacity at the Patoka terminal and 900,000 barrels of storage capacity at the St. James terminal. This new tankage will be completed in 2010 and complements the marine dock that is near completion at the St. James location. The cost of the project at the St. James terminal in aggregate is estimated to be approximately \$132 million. Additionally, the expansion of our Patoka Terminal with approximately 800,000 barrels of additional storage capacity for crude oil service has been approved and will be completed in 2011 at an approximate cost of \$28 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 did not meet certain project milestone dates and other economic conditions set forth in our agreements with our customers, and we could not meet certain key conditions in each of our agreements. As of the end of 2009, we have formally cancelled two of three agreements and are in the process of canceling a third agreement. We are in discussions with each of the three key customers and are working on developing new replacement agreements that reflect revised terms and conditions and a downsized initial project.

The project is subject to regulation by a number of state, local and federal agencies and regulatory bodies. The regulatory processes are complex and interrelated with our customer negotiations. These regulatory bodies include the Los Angeles Board of Harbor Commissioners, the South Coast Air Quality Management District, various departments of the City of Los Angeles, the Port 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 and execution of a land lease (that may also require a dock construction agreement) with the Port of Los Angeles, satisfaction of environmental permit requirements and receipt of other approvals.

The project Environmental Impact Report (EIR) was approved by the Board of Harbor Commissioners of the Port of Los Angeles on November 20, 2008 and subsequently, through the denial of an appeal of the Harbor Commission action, by the Los Angeles City Council on April 15, 2009. On May 15, 2009 a Petition for Writ of Mandate alleging a violation of the California Environmental Quality Act (CEQA) and violation of the Los Angeles municipal code and charter was filed in the Los Angeles Superior Court against the City of Los Angeles, the Port of Los Angeles, the Los Angeles Board of Harbor Commissioners and Pacific L. A. Marine Terminal LLC (PLAMT). This issue was formally heard by the court on January 15, 2010 and a final ruling was issued in favor of the respondents on January 19, 2010. All remaining permits and legal agreements related to the project are expected to be finalized in 2010.

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, requirements and protections required by the governing bodies. We have reduced the scope of the project and have completed an updated cost estimate for the Pier 400 project, and based on conditions existing in late 2009 we estimate that the project will cost approximately \$445 million (plus, potentially, an amount for dock construction) to complete, including \$76 million of costs associated with emission reduction credits and development and engineering costs incurred to date and \$63 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 1.5 million barrels of storage.

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.

During 2010, we intend to begin upgrading and improving our Bumstead LPG storage facility, which will increase the capacity by approximately 700,000 barrels. This project is expected to be completed late in 2010 at a cost of approximately \$17 million.

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.

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 Facilities

Pine Prairie. As a strategically located, high-deliverability storage facility, Pine Prairie has attracted customers whose storage needs include both traditional seasonal storage services and short-term storage services. Pine Prairie is located northwest of Lafayette, Louisiana and is strategically positioned relative to several major market hubs, including:

- the Henry Hub, which is the delivery point for NYMEX natural gas futures contracts and is located approximately 50 miles to the southeast of Pine Prairie;
- the Carthage Hub in east Texas, which is located approximately 150 miles northwest of Pine Prairie; and
- the Perryville Hub in north Louisiana, which is located approximately 130 miles north of Pine Prairie.

Pine Prairie’s pipeline header system, which includes an aggregate of 74 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, is directly connected to eight large-diameter interstate pipelines through nine interconnects that service both conventional and unconventional natural gas production in Texas and Louisiana, including production from existing and emerging shale plays, as well as Gulf of Mexico production and LNG imports. These interconnects also provide direct or indirect access to each of the market hubs described above and to consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast regions of the United States. This interconnectivity, combined with existing compression capacity and approximately 50 MMcf per day of leased third-party pipeline transportation capacity as of December 31, 2009, gives Pine Prairie the operational flexibility to receive from and deliver to multiple pipelines simultaneously.

Pine Prairie began commercial operations in October 2008 and currently has 14 Bcf of working gas storage capacity in two caverns, and planned expansions that will increase Pine Prairie’s total capacity to 42 Bcf by mid-2012 and 45 Bcf by mid-2015, making it one of the largest high-deliverability salt-cavern natural gas storage facilities in North America. Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie facility significantly beyond our current permitted capacity of 48 Bcf.

Bluewater. The Bluewater gas storage facility is located in the State of Michigan, which contains more natural gas storage capacity than any other state in the U.S., and primarily services seasonal storage needs throughout the Midwest and Northeast portions of the U.S. and the Southeast portion of Canada. Bluewater’s 30-mile, 20-inch diameter pipeline header system is supported by 13,350 horsepower of compression and is connected to three interstate and three intrastate natural gas pipelines that provide access to the major market hubs of Chicago, Illinois and Dawn, Ontario, which supply natural gas to eastern Ontario and the northeastern United States. These interconnects also provide access to natural gas utilities that serve local markets in Michigan and Ontario.

Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs and we expect to increase Bluewater’s working gas capacity by 2 Bcf ratably over a 10-year period beginning in 2011. Bluewater also leases third-party storage capacity and pipeline transportation capacity from time to time to increase its operational flexibility and enhance its service offerings. As of December 31, 2009, we had leased approximately 3 Bcf of additional capacity at third-party natural gas storage facilities as well as 329 MMcf per day of related pipeline transportation capacity.

Supply and Logistics Segment

Our supply and logistics 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 that the majority of activities that are carried out within our supply and logistics segment 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, 2009, our supply and logistics 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 supply and logistics segment also employs a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 10 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;
- 522 trucks and 630 trailers; and
- 1,473 railcars.

In connection with its operations, the supply and logistics 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 supply and logistics 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. Supply and logistics activities involve relatively large volumes of transactions, often with lower overall margins than transportation and facilities operations. Supply and logistics activities for LPG typically consist of smaller volumes per transaction relative to crude oil.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2009 (in thousands of barrels per day):

	<u>Volumes</u>
Crude oil lease gathering purchases.....	612
Refined products sales	35
LPG sales	105
Waterborne foreign crude oil imported.....	<u>55</u>
Supply & Logistics activities total.....	<u><u>807</u></u>

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 years. 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 it on third-party tankers.

We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that generally 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 activities involved in the supply, logistics and distribution of crude oil and LPG are complex and require 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 price 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 entering into physical sales contracts with third parties, 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 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 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 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 \$1 per barrel to 100% of their contracted amounts. Generally, sales of LPG and refined products settle within 10 days of the invoice date.

Certain activities in our supply and logistics segment are affected by seasonal aspects, primarily with respect to LPG supply and logistics 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 23 years, NYMEX West Texas Intermediate 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. Segment profit from our supply and logistics 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 supply, logistics and distribution 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 generally has a 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 is favorable to 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 duration 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 supply and logistics 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 supply and logistics 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 our core business; rather, those risks arise as a result of engaging in the trading activity. Our policy is to manage the enterprise level risks inherent in our core businesses, rather than trying to profit from trading activity. Our risk management policies and procedures are designed to monitor NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity to help ensure that our hedging activities address our risks. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities 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. Our approved strategies are intended to mitigate and manage enterprise level risks that are inherent in our core businesses.

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. We do not acquire and hold physical inventory, futures contracts or other derivative instruments 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 supply and logistics activities, we purchase crude oil, refined products and LPG from thousands of locations and 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 and other uncontrollable events that occur within each month. 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. This activity is monitored independently by our risk management function and must take place within predefined limits and authorizations.

Geographic Data; Financial Information about Segments

See Note 15 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Company, LLC accounted for 14%, 14% and 19% of our revenues for each of the three years ended December 31, 2009, 2008 and 2007, respectively. Valero Marketing & Supply Company accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 12%, 12% and 11% of our revenues for each of the three years ended December 31, 2009, 2008 and 2007, respectively. No other customers accounted for 10% or more of our revenues during any of the last three years. The majority of revenues from these customers pertain to our supply and logistics 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 with respect to our supply and logistics 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, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain major pipeline companies and independent storage providers have existing storage facilities connected to their systems that compete with some of our facilities.

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. 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 changes 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 Pipeline and Hazardous Materials Safety Administration ("the PHMSA") pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended (the "HLPESA"). The HLPESA imposes safety requirements on the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Federal regulations implementing the HLPESA 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 HLPESA 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 \$25 million in 2009, \$23 million in 2008 and \$15 million in 2007. Based on currently available information, our preliminary estimate for 2010 is that we will incur approximately \$11 million in operational expenditures and approximately \$25 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 HLPESA and the more recent 2002 and 2006 amendments.

Effective July 2008, PHMSA amended 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 located within a defined “buffer” area around a USA 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. The amended rules narrow 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. We have less than 300 miles of pipeline subject to the amended rules 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 U.S. 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 an attack.

The DOT has adopted American Petroleum Institute Standard 653 (“API 653”) as the standard for the inspection, repair, alteration and reconstruction of steel aboveground petroleum storage tanks subject to DOT jurisdiction. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Initial compliance, subject to an applicable waiver or stay, was required in May 2009. Costs associated with this program were approximately \$22 million, \$41 million and \$18 million in 2009, 2008 and 2007, respectively. For 2010, we have budgeted approximately \$28 million in connection with continued API 653 compliance activities and similar new EPA regulations for non-DOT tanks. Certain storage tanks may be taken out of service if we believe the cost of compliance will exceed the value of the storage tanks or replacement tankage may be constructed. In addition, market conditions may result in a significant demand for storage capacity. Accordingly, we may elect to spend more in 2010 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 have incurred and will continue 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 \$20 million in 2009, \$8 million in 2008 and \$6 million in 2007 on these types of costs. Our preliminary estimate for 2010 is approximately \$21 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, which are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended, (“RCRA”) and analogous state and provincial laws. Many of the wastes that we generate are not subject to the most stringent requirements of RCRA 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 hazardous wastes under RCRA, 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 typically 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, 2009, we had incurred approximately \$16 million of remediation costs associated with these sites, while SOP’s share has been approximately \$6 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 \$18 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. For example, EPA has recently proposed a significant tightening of the national ambient air quality standards for ozone which, if adopted, could require significant reductions in emissions of volatile organic compounds and nitrogen oxides in regions of the U.S. that have not previously been subject to the most stringent emissions limitations.

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 December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of GHGs from motor vehicles that could also lead to the imposition of GHG emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions

from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. Although the vast majority of our facilities were not subject to the EPA's GHG reporting rule adopted in September 2009. EPA has indicated that it is evaluating whether the rule should be applied to oil and gas production activities, perhaps on a field-wide basis.

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. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events, that could have an adverse effect on our assets and operations.

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.

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 in the U.S. is produced by rates that are either grandfathered or set by agreement with one or more shippers. In Canada, rates are set to cover operating costs and a return on capital, without specific agreements with shippers. Shippers may make application to federal or provincial regulatory agencies if they disagree with rates that have been set.

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 in U.S. interstate commerce or sold by a natural gas company via interstate commerce for resale. The FERC has granted our Pine Prairie and Bluewater gas storage facilities the authority to charge market-based rates.

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, imposition of creditworthiness and credit support requirements applicable to customers and relationships among 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. The FERC found that Pine Prairie qualified for this exemption from the standards of conduct in January 2006 and Bluewater qualified for this exemption in October 2006.

In November 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, in October 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 Pine Prairie and Bluewater. However, requests for rehearing are pending with the FERC. Accordingly, there may be further modifications to the Standards of Conduct upon rehearing.

Energy Policy Act of 2005. Pursuant to the EAct 2005 and related regulations, 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. EAct 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.

Other Proposed Regulation. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been heavily regulated. Accordingly, we cannot provide assurances that the less stringent and pro-competition regulatory approach recently pursued by the FERC and Congress will continue.

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 an attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

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

Title to Properties and Rights-of-Way

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

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

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

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including PMC (Nova Scotia) Company) employed approximately 3,400 employees at December 31, 2009. 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. One of the collective bargaining agreements is scheduled for renegotiation in September 2012, while the other agreement is in effect until September 30, 2010. 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 dividend payments and are treated as distributions to our unitholders.

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

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 gas storage facility and 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 supply and logistics 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 risk policies cannot eliminate all risks. In addition, any non-compliance with our risk 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 derivative contracts. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other hand. Our policy is not to acquire and hold physical inventory, futures contracts or derivative products for the purpose of speculating on commodity price changes. These policies and practices cannot, however, eliminate all 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 risks on certain of our inventory, such as linefill, which must be maintained in order to transport crude oil on our pipelines. In an effort to maintain a balanced position, specifically authorized personnel can purchase or sell an aggregate limit of up to 810,000 barrels of crude oil, refined products and LPG. Although this activity is monitored independently by our risk management function, it exposes us to risks within predefined limits and authorizations.

In addition, our operations involve the risk of non-compliance with our risk policies. 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 risk 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 five 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 more than two times the miles of pipeline we owned six years ago. We have also increased our terminalling and storage capacity and operate several facilities on or near navigable waters and domestic water supplies. Although we have implemented programs intended to enhance the integrity of our assets (discussed below), as we acquire additional assets we historically have observed an increase in the number of releases of liquid hydrocarbons into the environment. These releases expose us to potentially substantial expense, including clean-up and remediation costs, fines and penalties, and third party claims for personal injury or property damage related to past or future releases. Some of these expenses could increase by amounts disproportionately higher than the relative increase in pipeline mileage and the increase in revenues associated therewith. During 2006 and 2007, we acquired refined products pipeline and terminalling assets. These assets are also subject to significant compliance costs and liabilities. In addition, because of their increased volatility and tendency to migrate farther and faster than crude oil, releases of refined products into the environment can have a more significant impact than crude oil and require significantly higher expenditures to respond and remediate. The incurrence of such expenses not covered by insurance, indemnity or reserves could materially adversely affect our results of operations.

We currently devote substantial resources to comply with DOT-mandated pipeline integrity rules. The 2006 Pipeline Safety Act, enacted in December 2006, requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. 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 2010 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 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 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. 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 supply and logistics 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 supply and logistics 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 supply and logistics 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.

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.

Our sales of oil, natural gas, NGLs and other energy commodities, and related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the FERC and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGLs or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, to the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC's regulations and policies, or with an interstate pipeline's tariff, could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We face competition in our transportation, facilities and supply and logistics 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 natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain major pipeline companies and independent storage providers have existing storage facilities connected to their systems that compete with some of our facilities.

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, 2009, our consolidated debt outstanding was approximately \$5.2 billion, consisting of approximately \$4.1 billion principal amount of long-term debt (including senior notes) and approximately \$1.1 billion of short-term borrowings. As of December 31, 2009, we had approximately \$950 million 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—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 supply and logistics 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, 2009, we had approximately \$5.2 billion of consolidated debt, of which approximately \$3.8 billion was at fixed interest rates and approximately \$1.4 billion was at variable interest rates (including \$300 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 supply and logistics 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 into 2009, impacted the exchange rate. The average monthly exchange rate for the Canadian dollar to U.S. dollar ranged between \$1.05:1 and \$1.26:1 during 2009.

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, 2009, we had \$1.3 billion of goodwill, of which approximately \$875 million was recorded 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 goodwill was impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners’ equity and increase in balance sheet leverage as measured by debt to total capitalization.

Our natural gas storage facilities are new and have limited operating history. The facilities may not be able to deliver as anticipated, which could prevent us from meeting our contractual obligations and cause us to incur significant costs.

Although we believe that our operating gas storage facilities at Bluewater and Pine Prairie have been designed to meet our contractual obligations with respect to wheeling, injection, withdrawal and gas specifications, the facilities are new and have a limited operating history. If we fail to wheel, inject or withdraw natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, we could incur significant costs to satisfy our contractual obligations.

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 66²/₃% of our outstanding units (including units held by our general partner or its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

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

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and
- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders' ability to influence the manner or direction of management.

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

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

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

- an existing unitholder's proportionate ownership interest in the Partnership will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- 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 to transfer 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 many of our operating subsidiaries 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, 2009, our total outstanding debt was approximately \$5.2 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 additional entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or if we become subject to material 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, deductions or credits 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.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, or the IRS, on this or any other tax matter affecting us.

Despite the fact that we are classified as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

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.

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 has historically been 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 refers to 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 the 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. Additionally, in December 2008, the Fifth Protocol to the U.S./Canada Tax Treaty was ratified and contained language that increases the withholding tax on dividends and intercompany interest effective in 2010. As a result of these collective changes, we are evaluating a number of alternatives to restructure our Canadian subsidiaries to optimize both entity and equity owner level taxes. We anticipate effecting any structural changes in 2010 or early 2011.

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 our filing two tax returns 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 calendar year, 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 it would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were 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. 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, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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. 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 U.S. Environmental Protection Agency (the "EPA"), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately \$5 million to \$6 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 L.P., et al — Debtors (U.S. Bankruptcy Court — Delaware). We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude, which commenced in July 2008. 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 set off certain of our payables to the debtor against our receivables from the debtor. The aggregate amount subject to challenge is approximately \$23 million. Certain SemCrude creditors have also filed state court actions alleging a producer's lien on crude oil sold to SemCrude, and the continuation of such lien when SemCrude sold the oil to subsequent purchasers such as us. These suits may be consolidated and heard in the U.S. Bankruptcy Court in Delaware. 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.

United States of America 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 September 2008, the EPA filed a civil complaint against PPS, a subsidiary acquired in the Pacific merger, 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. In January 2010, the DOJ, EPA and PPS entered into a proposed consent decree, which will be published in the Federal Register and then be subject to a 30-day public comment period. If there are no objections prior to the end of the public comment period, the Court is expected to sign the consent decree. After the consent decree becomes effective, PPS will pay a civil penalty of \$1.3 million and comply with other requirements set forth in the consent decree, which include performance of additional remediation and restoration tasks. Total projected costs associated with this additional work are estimated at less than \$6 million. PPS is also prohibited from transferring ownership of Line 63 to an unaffiliated entity unless the transferee agrees in writing to be bound by any provisions of the consent decree that have not been previously satisfied. This prohibition on transfer will not apply if PPS retains a portion of ownership and continues as operator of the line.

ExxonMobil Corp. v. GATX Corp. (Superior Court of New Jersey — Gloucester County). This Pacific legacy matter was filed by ExxonMobil in April 2003 and 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. We estimate that the maximum potential cost to effectively remediate ranges up to \$10 million although the New Jersey Department of Environmental Protection (“NJDEP”) is asserting a much larger expenditure. Both ExxonMobil and GATX were prior owners of the terminal. We contend that ExxonMobil 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. We are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the contamination.

New Jersey Dep't of Environmental Protection v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX and ExxonMobil to recover natural resources damages associated with, and to require remediation of, the contamination. ExxonMobil and GATX have filed third-party demands against PAT, seeking indemnity and contribution. NJDEP environmental consultants have asserted a significant clean-up expense as indicated. Discussions with the NJDEP have commenced.

EPA v. Rocky Mountain Pipeline System. In February 2009, we received a request for information from EPA regarding aspects of the fuel handling activities of Rocky Mountain Pipeline System (“RMPS”), a subsidiary acquired in the Pacific merger, at two truck terminals in Colorado. These activities, performed at the request of customers, included the mixture of certain blendstocks with gasoline. We provided the information requested, and cooperated in EPA's investigation of such activities. In January 2010, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the Clean Air Act (“CAA”) related to registration, sampling, recording and reporting in connection with such activities. EPA further alleges that the violations occurred on an ongoing basis from October 2006 through February 2009. We plan to engage in discussion with EPA, and to emphasize factors intended to mitigate the severity of any penalties imposed. In December 2009, RMPS self-reported late filing of certain reports required under Clean Air Act Diesel Fuel Regulations. All reports have been filed.

Other Pacific-Legacy Matters. At the time of its merger with Plains, Pacific had completed a number of acquisitions that had not been fully integrated into its operations. Accordingly, we have and may become aware of various instances in which some of these operations may not have been fully compliant with applicable environmental and safety regulations. Although we have been working to bring all of these operations into compliance with applicable requirements, any past noncompliance could result in the imposition of fines, penalties or corrective action requirements by governmental entities. Although we believe that our operations are presently in material compliance with applicable requirements, it is possible that EPA or other governmental entities may seek to impose fines, penalties or performance obligations on us, or on a portion of our operations, as a result of any past noncompliance that may have occurred.

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, 2009, our reserve for environmental liabilities totaled approximately \$62 million, of which approximately \$10 million is classified as short-term and \$52 million is classified as long-term. At December 31, 2009, we have recorded receivables totaling approximately \$3 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 may be in excess of the reserve 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. Our environmental insurance coverage is generally structured to cover sudden environmental events but not gradual activities which may continue unnoticed for a material period of time. 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 and wind damage exposures, incorporate higher retention in our insurance arrangements, pay higher premiums or some combinations of such actions.

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.