

PLAINS ALL AMERICAN PIPELINE LP  
Form 10-K  
February 26, 2010  
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**UNITED STATES**  
**SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

**Form 10-K**

(Mark One)

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

**For the fiscal year ended December 31, 2009**

or

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

Commission file number 1-14569

**PLAINS ALL AMERICAN PIPELINE, L.P.**

(Exact name of registrant as specified in its charter)

**Delaware**

(State or other jurisdiction of  
incorporation or organization)

**333 Clay Street, Suite 1600, Houston, Texas**  
(Address of principal executive offices)

**76-0582150**

(I.R.S. Employer  
Identification No.)

**77002**

(Zip Code)

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(713) 646-4100

(Registrant's telephone number, including area code)

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

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

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

None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every

Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  No

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

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

Large Accelerated Filer

Accelerated Filer

Non-Accelerated Filer   
(Do not check if a smaller reporting company)

Smaller Reporting Company

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately \$4.8 billion on June 30, 2009, based on \$42.55 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 22, 2010, there were outstanding 136,135,988 Common Units.

### **DOCUMENTS INCORPORATED BY REFERENCE**

**NONE**

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**PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES**

**FORM 10-K 2009 ANNUAL REPORT**

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**FORWARD-LOOKING STATEMENTS**

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and statements regarding our business strategy, plans and objectives for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results to differ materially from the results anticipated in the forward-looking statements. These factors include, but are not limited to:

- failure to implement or capitalize on planned internal growth projects;
  
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
  
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
  
- the effectiveness of our risk management activities;
  
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
  
- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;
  
- shortages or cost increases of power supplies, materials or labor;
  
- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

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- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;
- the effects of competition;
- interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;
- increased costs or lack of availability of insurance;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- the currency exchange rate of the Canadian dollar;

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- weather interference with business operations or project construction;
- risks related to the development and operation of natural gas storage facilities;
- future developments and circumstances at the time distributions are declared;
- general economic, market or business conditions and the amplification of other risks caused by deteriorated financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

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

**PART I**

**Items 1 and 2. *Business and Properties***

**General**

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K 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.

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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.).



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

**Partnership Structure**

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(1) Based on Form 4 filings for executive officers and directors, 13D filings for Paul G. Allen and Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 25 million limited partner units, representing approximately 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.

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(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.

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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*

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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

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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

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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):

Acquisition	Date	Description	Approximate Purchase Price
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.



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**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](http://www.eia.doe.gov)).

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	2009 (1)	2010	Projected 2011	2015
	(In millions of barrels per day)			
<b>Supply</b>				
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	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

	2009 (1)	2010	Projected 2011	2015
	(In millions of barrels per day)			
<b>Demand</b>				
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

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(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

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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](http://www.eia.doe.gov)). The amounts in the 2009 column are based on the twelve months from November 2008 to October 2009.

	Actual 2009	2010 (In millions of barrels per day)	Projected 2011	2015
<b>Supply</b>				
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	18.7	19.2	19.8	20.2

The Department of Energy segregates the United States into five Petroleum Administration Defense Districts ( PADDs ), which are used by the energy industry for reporting statistics regarding crude oil supply and demand. The table below sets forth supply, demand and shortfall information for each PADD for the twelve months ended October 2009 and is derived from information published by the EIA (see EIA website at [www.eia.doe.gov](http://www.eia.doe.gov)) (in millions of barrels per day).

Petroleum Administration Defense District	Regional Supply	Refinery Demand	Supply Shortfall
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.	5.2	14.4	(9.2)

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;

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- 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:

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- 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.

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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

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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.

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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.

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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:

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

(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

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*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.

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The Basin system consists of four primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland; (ii) barrels that are shipped from Midland to connecting carriers at Colorado City; (iii) barrels that are shipped from Midland and Colorado City to connecting carriers at either Wichita Falls or Cushing and (iv) foreign and Gulf of Mexico barrels that are delivered into Basin at Wichita Falls and delivered to connecting carriers at Cushing. The system also includes approximately 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),

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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.

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*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 refineries 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.

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*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;

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- 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.

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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)
<b>Crude Oil and Refined Products</b>	
<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
<b>Subtotal</b>	<b>51</b>
<b>LPG</b>	
<i>Bumstead</i>	2
<i>Tirzah</i>	1
<i>Other</i>	3
<b>Subtotal</b>	<b>6</b>
<b>Natural Gas</b>	
<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.

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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

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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

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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.

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*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.

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*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:

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- 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):

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

*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

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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.

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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.

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***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

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

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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.

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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.

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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.

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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.

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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 CO<sub>2</sub>. 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.

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*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.

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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.

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***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

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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*

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*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***

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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

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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**



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*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

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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

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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.

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***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.

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***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.

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***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.

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***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.

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*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.

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

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

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 66 2/3% of our outstanding units (including units held by our general partner or its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

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

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

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

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

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

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

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



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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.

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***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.

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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.

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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.



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***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.

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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

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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 Dept 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

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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

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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.



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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.

Table of Contents**PART II****Item 5. Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities**

Our common units are listed and traded on the New York Stock Exchange ( NYSE ) under the symbol PAA. As of February 22, 2010, the closing market price for our common units was \$54.90 per unit and there were approximately 120,000 record holders and beneficial owners (held in street name). As of February 22, 2010, there were 136,135,988 common units outstanding.

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

		Common Unit Price Range			Cash Distributions (1)
	High		Low		
<b>2009</b>					
4th Quarter	\$	53.37	\$	45.45	\$ 0.9275
3rd Quarter	\$	50.33	\$	42.50	\$ 0.9200
2nd Quarter	\$	45.52	\$	36.25	\$ 0.9050
1st Quarter	\$	40.98	\$	34.00	\$ 0.9050
<b>2008</b>					
4th Quarter	\$	42.39	\$	23.25	\$ 0.8925
3rd Quarter	\$	48.36	\$	35.68	\$ 0.8925
2nd Quarter	\$	50.96	\$	44.54	\$ 0.8875
1st Quarter	\$	52.44	\$	43.93	\$ 0.8650

(1) Cash distributions for a quarter are declared and paid in the following calendar quarter. See the Cash Distribution Policy below for a discussion of our policy regarding distribution payments.

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

**Cash Distribution Policy**

We will distribute all of our available cash to our unitholders within 45 days following the end of each quarter in the manner described below. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

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

In addition to distributions on its 2% general partner interest, our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication and except for the agreed upon adjustment discussed below, to 15% of amounts we distribute in excess of \$0.450 per unit, 25% of the amounts we distribute in excess of \$0.495 per unit and 50% of amounts we distribute in excess of \$0.675 per unit.

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner may agree to reduce the amounts due to it as incentive distributions. Upon closing the acquisitions of Pacific Energy Partners LP ( Pacific ) in November 2006 and Rainbow Pipeline Company ( Rainbow ) in May 2008, our general partner agreed to reduce the amounts due to it as incentive distributions. Additionally, in connection with the PNGS acquisition in September 2009, our general partner agreed to further reduce its incentive distributions by an aggregate of \$8 million over the next two years \$1.25 million per quarter for the first four

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quarters and \$0.75 million per quarter for the next four quarters. This incentive distribution reduction became effective upon payment of our November 2009 quarterly distribution of \$0.9200 per limited partner unit. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions is \$83 million as displayed on an annual basis in the following table (in millions):

Acquisition	2007		2008		2009		2010		2011		Total
Pacific	\$	20	\$	15	\$	15	\$	10	\$	5	\$ 65
Rainbow				3		6		1			10
PNGS						1		5		2	8
Total	\$	20	\$	18	\$	22	\$	16	\$	7	\$ 83

Following the distribution in February 2010 (as discussed below), the aggregate remaining incentive distribution reductions will be approximately \$18 million.

We paid \$127 million to the general partner in incentive distributions in 2009. Additionally, on February 12, 2010, we paid a quarterly distribution of \$0.9275 per unit applicable to the fourth quarter of 2009, of which approximately \$40 million was paid to the general partner. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner.

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. No such default has occurred. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facilities and Long-Term Debt.

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters for information regarding securities authorized for issuance under equity compensation plans.

**Issuer Purchases of Equity Securities**

We did not repurchase any of our common units during the fourth quarter of fiscal 2009, and we do not have any announced or existing plans to repurchase any of our common units.

**Item 6. Selected Financial Data**

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2009, 2008, 2007, 2006 and 2005 and for the years then ended. The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.



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	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in millions, except for per unit data)				
<b>Statement of operations data:</b>					
Total revenues (1)	\$ 18,520	\$ 30,061	\$ 20,394	\$ 22,445	\$ 31,177
Income before cumulative effect of change in accounting principle (2)	\$ 580	\$ 437	\$ 365	\$ 279	\$ 218
Net income	\$ 580	\$ 437	\$ 365	\$ 285	\$ 218
Net income attributable to Plains	\$ 579	\$ 437	\$ 365	\$ 285	\$ 218
<b>Per unit data:</b>					
Basic net income before cumulative effect of change in accounting principle (2)	\$ 3.34	\$ 2.66	\$ 2.47	\$ 2.85	\$ 2.83
Basic net income after cumulative effect of change in accounting principle	\$ 3.34	\$ 2.66	\$ 2.47	\$ 2.93	\$ 2.83
Diluted net income before cumulative effect of change in accounting principle (2)	\$ 3.32	\$ 2.64	\$ 2.45	\$ 2.82	\$ 2.78
Diluted net income after cumulative effect of change in accounting principle	\$ 3.32	\$ 2.64	\$ 2.45	\$ 2.90	\$ 2.78
Declared distributions per limited partner unit (3)	\$ 3.62	\$ 3.50	\$ 3.28	\$ 2.87	\$ 2.58
<b>Balance sheet data (at end of period):</b>					
Total assets	\$ 12,358	\$ 10,032	\$ 9,906	\$ 8,715	\$ 4,120
Long-term debt	\$ 4,142	\$ 3,259	\$ 2,624	\$ 2,626	\$ 952
Total debt	\$ 5,216	\$ 4,286	\$ 3,584	\$ 3,627	\$ 1,330
Partners' capital	\$ 4,159	\$ 3,552	\$ 3,424	\$ 2,977	\$ 1,331
<b>Other data:</b>					
Net cash provided by (used in) operating activities	\$ 365	\$ 857	\$ 796	\$ (276)	\$ 24
Net cash used in investing activities	\$ (660)	\$ (1,339)	\$ (663)	\$ (1,651)	\$ (297)
Net cash provided by (used in) financing activities	\$ 312	\$ 464	\$ (124)	\$ 1,927	\$ 271
Capital expenditures:					
Acquisitions	\$ 393	\$ 735	\$ 125	\$ 3,021	\$ 40
Internal growth projects	\$ 364	\$ 491	\$ 525	\$ 332	\$ 149
Maintenance	\$ 81	\$ 81	\$ 50	\$ 28	\$ 14
Investments in unconsolidated subsidiaries	\$ 15	\$ 37	\$ 9	\$ 44	\$ 113

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	Year Ended December 31,				
	2009	2008	2007	2006	2005
<b>Volumes (4) (5) (6)</b>					
Transportation segment (average daily volumes in thousands of barrels):					
Tariff activities	2,836	2,851	2,712	2,106	1,799
Trucking	85	97	105	101	84
Transportation segment total	2,921	2,948	2,817	2,207	1,883
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)					
	56	53	46	25	22
Natural gas storage (average monthly capacity in billion cubic feet ( Bcf ))					
	26	14	13	13	4
LPG processing (average daily throughput in thousands of barrels)					
	15	17	18	12	
Facilities segment total (average monthly capacity in millions of barrels)					
	61	56	48	27	22
Supply & Logistics segment (average daily volumes in thousands of barrels):					
Crude oil lease gathering purchases	612	658	685	650	610
Refined products sales	35	26	11	N/A	N/A
LPG sales	105	103	90	70	56
Waterborne foreign crude imported	55	80	71	63	59
Supply & Logistics segment total	807	867	857	783	725

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

(2) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2006 change in our method of accounting for unit-based payment transactions would have been \$224 million for 2005. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been \$2.81 (\$2.76 diluted) for 2005.

(3) Our general partner is entitled, directly or indirectly, to receive 2% proportional distributions, and also incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 5 to our Consolidated Financial Statements.

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

(5) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for September 2005 through August 2009 are netted to our 50% interest in PNGS. September through December 2009 volumes represent our 100% interest in PNGS. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.



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

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

**Introduction**

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

Our discussion and analysis includes the following:

- Executive Summary
- Company Overview
- Overview of Operating Results, Capital Spending and Significant Activities
- Acquisitions and Internal Growth Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations

- Outlook
- Liquidity and Capital Resources

#### **Executive Summary**

#### ***Company Overview***

We provide transportation, storage, terminalling, supply and logistics services with respect to crude oil, refined products and LPG. We are also engaged in the development and operation of natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) 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.

See Results of Operations Analysis of Operating Segments for further discussion.

#### ***Overview of Operating Results, Capital Spending and Significant Activities***

During 2009, our operations provided favorable growth over 2008 and 2007 levels. All three of our segments provided favorable operating results, particularly our supply and logistics segment. The supply and logistics segment benefited from the favorable steep contango crude oil market structure early in the period. Our LPG margins also benefited from strong demand for propane. Our transportation and facilities operating results benefited from expansions in our asset base through acquisitions and our ongoing internal growth projects. Additional key items impacting 2009 include:

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- The issuance of 5,750,000 common units at \$36.90 per unit for net proceeds of approximately \$210 million in March 2009, and the issuance of 5,290,000 common units at \$46.70 per unit for net proceeds of approximately \$246 million in September 2009.
- The issuance and repayment of the following senior notes:
  - Issuance of \$350 million of 8.75% senior notes for net proceeds of approximately \$347 million in April 2009.
  - Issuance of \$500 million of 4.25% senior notes for net proceeds of approximately \$497 million in July 2009.
  - Repayment of \$175 million of 4.75% senior notes in August 2009.
  - Issuance of \$500 million of 5.75% senior notes for net proceeds of approximately \$494 million in September 2009.
  - Repayment of \$250 million of 7.13% senior notes in October 2009. We also recognized a loss of approximately \$4 million in conjunction with the early redemption of these notes.

**Acquisitions and Internal Growth Projects**

We completed a number of acquisitions and capital expansion projects in 2009, 2008 and 2007 that have impacted our results of operations. The following table summarizes our capital expenditures for acquisitions, internal growth projects, maintenance capital and investments in unconsolidated entities for the periods indicated (in millions):

	For the Year Ended December 31,		
	2009	2008	2007
Acquisition capital	\$ 393	\$ 735	\$ 125
Internal growth projects	364	491	525
Maintenance capital	81	81	50
Investment in unconsolidated entities	15	37	9
	\$ 853	\$ 1,344	\$ 709

**Acquisitions**

Acquisitions are financed using a combination of equity and debt, including borrowings under our credit facilities and the issuance of senior notes. Businesses acquired impact our results of operations commencing on the effective date of each acquisition. Our acquisition and capital expansion activities are discussed further in [Liquidity and Capital Resources](#) and in Note 3 to our Consolidated Financial Statements.

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Information regarding acquisitions completed in 2009, 2008 and 2007 is set forth in the table below (in millions):

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Acquisition	Effective Date	Acquisition Price	Operating Segment
PNGS	09/03/2009	\$ 215	Facilities
Other (1)	Various	178	Transportation & Facilities
2009 Total		\$ 393	
Rainbow	05/01/2008	\$ 687	Transportation
San Pedro and other	11/13/2008	48	Facilities
2008 Total		\$ 735	
Bumstead LPG Storage Facility	07/24/2007	\$ 52	Facilities
Tirzah LPG Storage Facility	10/2/2007	54	Facilities
Other	Various	19	Transportation and Supply & Logistics
2007 Total		\$ 125	

(1) Consists of six small acquisitions.

**Internal Growth Projects**

Our 2009 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2009, 2008 and 2007 projects (in millions):

Projects	2009	2008	2007
St. James - Phase III (1)	\$ 71	\$ 27	\$ 14
Nipisi storage and truck terminal (1)	35		
Kerrobert pumping project	34	9	
Rangeland tankage	31	12	
Cushing - Phase VII (1)	25		
Patoka tankage - Phase I	6	55	30
Patoka tankage - Phase II (1)	14	1	
Paulsboro tankage	11	30	2
Salt Lake City expansion	8	154	73
Fort Laramie tank expansion	2	20	12
St. James, Louisiana storage facility	2	17	68
Other projects (2)	125	166	326
Total	\$ 364	\$ 491	\$ 525

(1) These projects will continue into 2010. See Liquidity and Capital Resources Capital Expenditures and Distributions Paid to Our Unitholders and General Partner 2010 Capital Expansion Projects.

(2) Primarily consists of gas storage construction projects, pipeline connections, upgrades and truck stations, and new tank construction and refurbishing.



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**Critical Accounting Policies and Estimates**

*Critical Accounting Policies*

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

*Critical Accounting Estimates*

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

*Purchase and Sales Accruals.* We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. For the year ended December 31, 2009, we estimate that approximately 3%, 3%, 8% and 11% of annual revenues, cost of sales, operating income and net income attributable to Plains, respectively, were recorded using purchase and sales estimates. Accordingly, a 10% variance from this estimate would impact the respective line items by approximately 1% or less on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

*Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets.* In accordance with FASB guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recognized. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. We also expense the transaction costs as incurred in connection with each acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their

estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

Impairment testing entails estimating future net cash flows relating to the asset, based on management's estimate of market conditions including pricing, demand, competition, operating costs and other factors. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable.

We also compare our market capitalization to our book equity on a quarterly basis, to determine if there may be an indicator of impairment. As of December 31, 2009, our market capitalization exceeded the book value of our equity; therefore, since there were no events or changes in circumstances indicating impairment issues, we determined that it was not necessary to perform our goodwill impairment test as of December 31, 2009 (as performed during the prior year due to economic conditions). We will continue to monitor the market and any changes in circumstances to determine if a triggering event occurs and will perform a goodwill impairment analysis if deemed necessary. We did not have any goodwill impairments in 2009, 2008 or 2007. See Note 2 to our Consolidated Financial Statements for a further discussion of goodwill.

*Mark-to-Market Accrual.* In situations where we are required to mark-to-market derivatives, the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total annual revenues are based on estimates derived from internal valuation models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.



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*Accruals and Contingent Liabilities.* We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, insurance claims, asset retirement obligations, taxes and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, costs of medical care associated with worker's compensation and employee health insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately \$13 million. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

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

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

For the Class B units of Plains AAP, L.P., the total compensation expense recognized over the service period is equal to the grant date fair value of the Class B units that become earned. The Class B units become earned in various increments upon us achieving annualized distribution levels of \$3.50, \$3.75, \$4.00 and \$4.50. When earned, the Class B units will be entitled to participate in distributions paid by Plains AAP, L.P. in excess of \$11 million (as adjusted for debt service costs and excluding special distributions funded by debt) per quarter. Uncertainties involved in this estimate include the estimated date that we will achieve the annualized distribution levels required and the continued employment of personnel who have been awarded Class B units.

We recognized total compensation expense of approximately \$68 million, \$24 million and \$49 million in 2009, 2008 and 2007, respectively, related to equity awards granted under our various equity compensation plans. We cannot provide assurance that the actual fair value of our equity compensation awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.



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*Property, Plant and Equipment and Depreciation Expense.* We compute depreciation using the straight-line method based on estimated useful lives. We periodically evaluate property, plant and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property, plant and equipment a critical accounting estimate. In determining the existence of an impairment of carrying value, we make a number of subjective assumptions as to:

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

During 2009, we recognized impairments of less than \$1 million for assets taken out of service. Impairments of approximately \$5 million and \$1 million were recognized during 2008 and 2007, respectively.

*Allowance for Doubtful Accounts.* We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for additional discussion.

**Recent Accounting Pronouncements**

*Recent Accounting Pronouncements*

See Note 2 to our Consolidated Financial Statements for a discussion of recent accounting pronouncements that will impact us.

## **Results of Operations**

### *Analysis of Operating Segments*

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

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 15 to our Consolidated Financial Statements for a definition of segment profit (including an explanation of why this is a performance measure) and a reconciliation of segment profit to net income attributable to Plains.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the supply and logistics segment secures transportation and facilities services from the Partnership's other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. Facilities segment services are also obtained at rates generally consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our 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. Intersegment activities are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expense and general and administrative overhead expenses between segments based on management's assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

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	For the Twelve Months Ended December 31,			Favorable (Unfavorable)				
	2009	2008	2007	2009-2008		2008-2007		
				\$	%	\$	%	
	(In millions, except per unit data)							
Transportation segment profit	\$ 477	\$ 445	\$ 334	\$ 32	7%	\$ 111	33%	
Facilities segment profit	208	153	110	55	36%	43	39%	
Supply & Logistics segment profit	345	221	269	124	56%	(48)	(18)%	
Total segment profit	1,030	819	713	211	26%	106	15%	
Depreciation and amortization	(236)	(211)	(180)	(25)	(12)%	(31)	(17)%	
Interest expense	(224)	(196)	(162)	(28)	(14)%	(34)	(21)%	
Other income, net	16	33	10	(17)	(52)%	23	230%	
Income tax expense	(6)	(8)	(16)	2	25%	8	50%	
Net income	580	437	365	143	33%	72	20%	
Less: Net income attributable to noncontrolling interest	(1)			(1)	N/A			
Net income attributable to Plains	\$ 579	\$ 437	\$ 365	\$ 142	32%	\$ 72	20%	
Earnings per basic limited partner unit	\$ 3.34	\$ 2.66	\$ 2.47	\$ 0.68	26%	\$ 0.19	8%	
Earnings per diluted limited partner unit	\$ 3.32	\$ 2.64	\$ 2.45	\$ 0.68	26%	\$ 0.19	8%	
Basic weighted average units outstanding	130	120	113	10	8%	7	6%	
Diluted weighted average units outstanding	131	121	114	10	8%	7	6%	

**Transportation Segment**

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. The transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees.

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

Operating Results (1) (in millions, except per barrel amounts)	Year Ended December 31,			Favorable (Unfavorable)			
	2009	2008	2007	2009-2008		2008-2007	
				\$	%	\$	%
<b>Revenues (1)</b>							
Tariff activities	\$ 867	\$ 800	\$ 654	\$ 67	8%	\$ 146	22%
Trucking	94	127	117	(33)	(26)%	10	9%
Total transportation revenues	961	927	771	34	4%	156	20%
<b>Cost and Expenses (1)</b>							
Trucking costs	(63)	(88)	(80)	25	28%	(8)	(10)%
Field operating costs (excluding equity compensation expense)	(333)	(331)	(288)	(2)	(1)%	(43)	(15)%
Equity compensation expense - operations (2)	(9)	(1)	(5)	(8)	(800)%	4	80%
Segment G&A expenses (excluding equity compensation expense)	(61)	(56)	(50)	(5)	(9)%	(6)	(12)%
Equity compensation expense - general and administrative (2)	(25)	(11)	(19)	(14)	(127)%	8	42%
Equity earnings in unconsolidated entities	7	5	5	2	40%		

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Segment profit	\$	477	\$	445	\$	334	\$	32	7%	\$	111	33%
Maintenance capital	\$	57	\$	54	\$	34	\$	3	6%	\$	20	59%
Segment profit per barrel	\$	0.45	\$	0.41	\$	0.34	\$	0.04	10%	\$	0.07	21%

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Average Daily Volumes (in thousands of barrels per day) (3)	Year Ended December 31,			Favorable (Unfavorable)			
	2009	2008	2007	2009-2008		2008-2007	
				Volumes	%	Volumes	%
Tariff activities							
All American	40	45	47	(5)	(11)%	(2)	(4)%
Basin	394	377	378	17	5%	(1)	
Capline	193	219	235	(26)	(12)%	(16)	(7)%
Line 63/Line 2000	131	147	175	(16)	(11)%	(28)	(16)%
Salt Lake City Area Systems	131	93	101	38	41%	(8)	(8)%
West Texas/New Mexico Area Systems	368	372	369	(4)	(1)%	3	1%
Manito	63	70	73	(7)	(10)%	(3)	(4)%
Rainbow	183	129		54	42%	129	N/A
Rangeland	53	58	63	(5)	(9)%	(5)	(8)%
Refined products	100	109	109	(9)	(8)%		
Other	1,180	1,232	1,162	(52)	(4)%	70	6%
Tariff activities total	2,836	2,851	2,712	(15)	(1)%	139	5%
Trucking	85	97	105	(12)	(12)%	(8)	(8)%
Transportation segment total	2,921	2,948	2,817	(27)	(1)%	131	5%

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

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

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

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Segment profit from our pipeline capacity leases generally reflects a negotiated amount.

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

*Operating Revenues and Volumes.* As noted in the table above, our transportation segment revenues increased in each year and our volumes remained relatively consistent for 2009 compared to 2008 and increased approximately 5% for 2008 compared to 2007. Volumes were positively impacted by (i) the Rainbow acquisition completed in May 2008, which added approximately 129,000 barrels per day to average 2008 volumes and approximately 183,000 barrels per day to average 2009 volumes and (ii) the completion in the fourth quarter of 2008 of a 94-mile expansion of our Salt Lake Area system. The increases from these acquisition and expansion activities were generally offset in 2009 and partially offset in 2008 by volume fluctuations on various other pipeline segments as well as decreased trucking volumes over the three year period. The decreased trucking volumes were primarily due to decreased demand as well as an effort to eliminate lower margin activities.

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Revenues for the years ended December 31, 2009 and 2008 were positively impacted by the net effect of a number of factors including:

- The Rainbow acquisition contributed approximately \$16 million and \$50 million of incremental revenue to 2009 and 2008, respectively.
- Incremental revenues from completion of the Salt Lake City Area expansion added approximately \$7 million to revenues in 2009 relative to 2008 associated with volume increases.
- Loss allowance revenues increased by approximately \$22 million for 2009 compared to 2008 primarily related to a higher average realized price per barrel during 2009 (including the impact of gains from derivative activities). Loss allowance revenues increased by approximately \$31 million for 2008 compared to 2007 due to slightly higher volumes and an increase in the average realized price per barrel during most of 2008 relative to 2007.



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- Tariff rates increased on certain of our pipeline systems after the second quarter of each year as a result of indexing by the Federal Energy Regulation Commission ( FERC ). In addition, we had similar type rate increases on non-FERC regulated pipelines.
- Revenues for the year ended December 31, 2008 were impacted by a gain of approximately \$17 million related to a linefill hedge entered into in conjunction with the Rainbow acquisition.
- Trucking revenues decreased for 2009 compared to 2008 by approximately \$33 million, primarily related to the volume decrease discussed within our operating revenues and volumes lead in. Trucking revenues increased for 2008 compared to 2007 by approximately \$10 million due to the acquisition of trucking businesses in prior years.
- Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at average exchange rates prevailing for each month. During 2009, revenues from some of our Canadian pipeline systems were unfavorably impacted by the appreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar ( CAD ) to U.S. dollar ( USD ) exchange rate for 2009 was \$1.14 CAD: \$1.00 USD compared to an average of \$1.07 CAD: \$1.00 USD in 2008 and in 2007.
- Miscellaneous revenue and volume variances on various other systems, including the impacts of Hurricanes Gustav and Ike, both of which affected the Gulf Coast area during the third quarter of 2008.

*Costs and Expenses.* In general, our overall transportation costs and expenses have trended up primarily due to our continued growth through acquisitions and expansion activities. However, overall costs were favorably impacted in 2009 by the appreciation of the U.S. dollar relative to the Canadian dollar. Various factors impacting components of our cost structure include:

*Trucking Costs.* Trucking costs decreased in 2009 as compared to 2008 primarily as a result of decreased trucking volumes, as discussed above, and as a result of lower rates resulting from lower fuel costs. Trucking cost increased in 2008 as compared to 2007 primarily as a result of increased rates resulting from higher fuel costs. This increase was partially offset by lower costs resulting from lower trucking volumes.

*Field Operating Costs.* Field operating costs (excluding equity compensation charges as discussed below) increased \$2 million in 2009 over 2008 and \$43 million in 2008 over 2007. The primary driver of this increase was the Rainbow acquisition that was completed in May 2008, which added \$17 million for the year ended December 31, 2008, and an additional \$2 million for the year ended December 31, 2009. In addition, during the year ended December 31, 2009 we had increased payroll, benefit and maintenance costs that were offset by lower API 653, in-line inspection, utility and fuel costs. Costs related to API 653 and in-line inspections had increased in 2008 in an effort to meet the 2009 compliance deadline. In addition, utility and fuel costs had increased in 2008 as a result of higher rates, and decreased again in 2009 as fuel and power rates decreased. Our overall operating expenses also increased during 2008 as compared to 2007 due to general inflationary pressures experienced in the industry and from our expanded asset base including assets from the Pacific merger in late 2006.

*General and Administrative Expenses.* General and administrative expenses (excluding equity compensation charges as discussed below) have increased in 2009 compared to 2008 and in 2008 compared to 2007 related to our acquisitions and expansion activities as well as upward cost pressures from payroll and benefits and other personnel related costs.

*Equity Compensation Charges.* Equity compensation charges increased approximately \$22 million in 2009 compared to 2008 and decreased by \$12 million in 2008 as compared to 2007. Such variations are primarily the result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. At the end of 2009, our unit price was \$52.85 per common unit as compared to \$34.69 per common unit at the end of 2008 and \$52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

*Maintenance Capital.* The increase in maintenance capital in 2008 compared to 2007 is primarily due to increased investment applicable to in-line inspections and API 653 repairs in an effort to meet our May 2009 compliance deadline, general inflationary pressures experienced in the industry, our expanded asset base including assets from the Pacific merger in late 2006, and the Rainbow acquisition.

#### **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, natural gas and LPG, as well as LPG fractionation and

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isomerization services. The facilities segment generates revenue through a combination of month-to-month and multi-year leases and processing arrangements.

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

Operating Results (1) (in millions, except per barrel amounts)	For the Year Ended			Favorable (Unfavorable)			
	December 31,			2009-2008		2008-2007	
	2009	2008	2007	\$	%	\$	%
Storage and terminalling revenues (1)	\$ 362	\$ 270	\$ 210	\$ 92	34%	\$ 60	29%
Storage related costs	(5)			(5)	N/A		
Field operating costs (excluding equity compensation charge)	(120)	(104)	(84)	(16)	(15)%	(20)	(24)%
Equity compensation charge - operations (2)	(1)			(1)	N/A		
Segment G&A expenses (excluding equity compensation expense)	(26)	(18)	(18)	(8)	(44)%		
Equity compensation expense - general and administrative (2)	(10)	(4)	(8)	(6)	(150)%	4	50%
Equity earnings in unconsolidated entities	8	9	10	(1)	(11)%	(1)	(10)%
Segment profit	\$ 208	\$ 153	\$ 110	\$ 55	36%	\$ 43	39%
Maintenance capital	\$ 16	\$ 23	\$ 10	\$ (7)	(30)%	\$ 13	130%
Segment profit per barrel	\$ 0.29	\$ 0.23	\$ 0.19	\$ 0.06	26%	\$ 0.04	21%

Volumes (3) (4) (5)	For the Year Ended			Favorable (Unfavorable)			
	December 31,			2009-2008		2008-2007	
	2009	2008	2007	Volumes	%	Volumes	%
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	56	53	46	3	6%	7	15%
Natural gas storage (average monthly capacity in bcf)	26	14	13	12	86%	1	8%
LPG processing (average throughput in thousands of barrels per day)	15	17	18	(2)	(12)%	(1)	(6)%
Facilities segment total (average monthly capacity in millions of barrels)	61	56	48	5	9%	8	17%

(1) Revenues include intersegment amounts.

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

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

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(4) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for 2008 and January through August 2009 are netted to our 50% interest in PNGS. September through December 2009 volumes represent our 100% interest in PNGS.

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

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

*Operating Revenues and Volumes.* As noted in the table above, our facilities segment revenues and volumes increased for 2009 compared to 2008 and for 2008 compared to 2007. The significant variances in volumes and revenues between 2009, 2008 and 2007 are discussed below:

- **Acquisitions** Revenues and volumes for 2009 compared to 2008 were impacted by the PNGS acquisition, which closed during the third quarter of 2009 and the acquisition of a natural gas processing business, which closed during the second quarter of 2009. Revenues and volumes for 2009 compared to 2008 were also impacted by the San Pedro acquisition, which closed during the fourth quarter of 2008. Such acquisitions contributed approximately \$36 million in additional revenue for the year ended December 31, 2009.

Revenues and volumes for 2008 compared to 2007 were impacted by the Bumstead and Tirzah acquisitions in 2007 in addition to the San Pedro acquisition that we closed during the fourth quarter of 2008. The Bumstead acquisition was completed in the third quarter of 2007 and the Tirzah acquisition was completed in the fourth quarter of 2007. Such acquisitions contributed approximately \$13 million in additional revenue for the year ended December 31, 2008.

- **Expansion Projects** Expansion projects also resulted in an increase in revenues and volumes in 2009 compared to 2008, which included expansion projects at the Paulsboro, Patoka, St. James and Ft. Laramie facilities. Revenues for these facilities increased by a combined \$31 million for 2009. Aggregate volumes increased by approximately 5 million barrels for 2009 at these facilities.

Expansion projects also resulted in an increase in revenues and volumes in 2008 compared to 2007, which included expansion projects at the Cushing, Martinez and St. James facilities. Revenues for these facilities increased by a combined \$37 million for 2008. Aggregate volumes increased by approximately 6 million barrels for 2008 at these facilities.

- **Leased Tankage** Revenues for the year ended December 31, 2009 also increased as a result of general escalations on existing leases.

*Field Operating Costs.* Field operating costs (excluding equity compensation charges as discussed below) increased in most categories during the years ended December 31, 2009 and 2008 primarily due to our continued growth through (i) additional tankage placed into service over the last few years at various terminals, including Cushing, Martinez, Paulsboro and St. James and (ii) acquisitions such as the PNGS and natural gas processing acquisitions completed in 2009 and the Tirzah and Bumstead acquisitions completed during 2007.

*General and Administrative Expenses.* Our general and administrative expenses (excluding equity compensation charges as discussed below) increased during the year ended December 31, 2009 primarily due to our continued growth through acquisitions, such as the PNGS and natural gas processing acquisitions completed in 2009.

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*Equity Compensation Charges.* Equity compensation charges increased approximately \$7 million in 2009 compared to 2008 and decreased approximately \$4 million in 2008 as compared to 2007. Such variations are primarily as a result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. At the end of 2009, our unit price was \$52.85 per common unit as compared to \$34.69 per common unit at the end of 2008 and \$52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

*Maintenance Capital.* The decrease in maintenance capital for the year ended December 31, 2009 compared to the year ended December 31, 2008 is primarily due to a decrease in API 653 repairs required to meet our May 2009 compliance deadline. The increase in maintenance capital for 2008 compared to 2007 was primarily due to maintenance capital incurred at various terminals, including the Martinez, Richmond, LA Basin and Cushing terminals to meet the 2009 deadline for API 653, general inflationary pressures experienced in the industry, and our expanded asset base including assets from the Pacific merger in late 2006.

### **Supply and Logistics Segment**

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes.

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

The following table sets forth our operating results from our supply and logistics segment for the periods indicated:

Operating Results (1) (in millions, except per barrel amounts)	For the Year Ended			Favorable (Unfavorable)			
	2009	December 31, 2008	2007	2009-2008		2008-2007	
				\$	%	\$	%
Revenues	\$ 17,759	\$ 29,350	\$ 19,858	\$ (11,591)	(39)%	\$ 9,492	48%
Purchases and related costs (2)	(17,141)	(28,873)	(19,366)	11,732	41%	(9,507)	(49)%
Field operating costs (excluding equity compensation charge)	(183)	(185)	(154)	2	1%	(31)	(20)%
Equity compensation charge - operations (3)	(1)			(1)	N/A		
Segment G&A expenses (excluding equity compensation charge)	(67)	(63)	(52)	(4)	(6)%	(11)	(21)%
Equity compensation charge - general and administrative (3)	(22)	(8)	(17)	(14)	(175)%	9	53%
Segment profit	\$ 345	\$ 221	\$ 269	\$ 124	56%	\$ (48)	(18)%
Maintenance capital	\$ 8	\$ 4	\$ 6	4	100%	(2)	(33)%
Segment profit per barrel (4)	\$ 1.17	\$ 0.70	\$ 0.86	\$ 0.47	67%	\$ (0.16)	(19)%

Average Daily Volumes (5) (in thousands of barrels per day)	For the Year Ended			Favorable (Unfavorable)			
	2009	December 31, 2008	2007	2009-2008		2008-2007	
				Volumes	%	Volumes	%
Crude oil lease gathering purchases	612	658	685	(46)	(7)%	(27)	(4)%
Refined products sales	35	26	11	9	35%	15	136%
LPG sales	105	103	90	2	2%	13	14%
Waterborne foreign crude oil imported	55	80	71	(25)	(31)%	9	13%
Supply & Logistics segment total	807	867	857	(60)	(7)%	10	1%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately \$11 million, \$21 million and \$44 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

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

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



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Generally, we expect a base level of earnings from our supply and logistics segment that may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. A contango market is favorable to our commercial strategies that are associated with storage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. However, in this environment, there is little incentive to store crude oil as current prices are above future delivery prices. In addition, certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average rates. Our revenues from the supply and logistics segment were unfavorably impacted in 2009 compared to 2008 as a result of the appreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar to U.S. dollar exchange rate for 2009 was \$1.14 CAD: \$1.00 USD compared to an average of \$1.07 CAD: \$1.00 USD in 2008 and in 2007.

*Operating Revenues and Volume.* Revenues net of purchases and related costs increased by approximately 30%, or approximately \$141 million, in 2009 as compared to 2008. The primary reasons for the stronger performance in 2009 were (i) strong crude oil contango margins in the first four months of the year (during this period the contango market was as wide as \$8.49 per barrel); (ii) strong LPG margins in the fourth quarter of the year due to strong crop drying demand in the quarter and colder than normal weather the latter half of the quarter; (iii) 2008 was negatively impacted by Hurricanes Gustav and Ike (we estimate the negative impact to be approximately \$15 million); and (iv) derivative activities, net of inventory valuation adjustments, were a net gain of \$62 million in 2009 compared to a net loss of \$7 million in 2008. The derivative gains in 2009 are generally offset by future physical positions that are not included in the mark-to-market calculation for various reasons including that they qualify for the normal purchase and normal sale scope exception under FASB guidance. These items more than offset a lower net margin from our lease gathering activities, which was primarily due to lower volumes as we eliminated some of our less profitable purchases.

Revenues net of purchases and related costs decreased by approximately 3% in 2008 as compared to 2007. The primary reason for the decrease was that 2008 was negatively impacted by Hurricanes Gustav and Ike. We estimate the negative impact to be approximately \$15 million. Lease gathering margins were also stronger in 2008 as compared to 2007; however, this was largely offset by a decline in crude oil contango market opportunities in 2008.

*Field Operating Costs.* Field operating costs (excluding equity compensation charges as discussed below) in 2009 were in line with 2008 costs. Field operating costs were approximately \$31 million higher in 2008 than in 2007. Such costs relate primarily to our lease gathering activities where our net revenues (revenues less purchases and related costs) increases more than offset the cost increases in 2008.

*General and Administrative Expenses.* General and administrative expenses (excluding equity compensation charges as discussed below) increased approximately 6% in 2009 compared to 2008, primarily due to increased payroll and benefit costs. Similarly, such costs increased in 2008 as compared to 2007 due to (i) increased payroll and benefit costs and (ii) a change in allocation methodology between the facilities and supply and logistics segments.

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*Equity Compensation Charges.* Equity compensation charges increased approximately \$15 million in 2009 compared to 2008 and decreased approximately \$9 million in 2008 as compared to 2007. Such variations are primarily as a result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. At the end of 2009, our unit price was \$52.85 per common unit as compared to \$34.69 per common unit at the end of 2008 and \$52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

*Maintenance Capital.* Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital for the year ended December 31, 2009 compared to the year ended December 31, 2008 is primarily due to truck and trailer fleet replacements and rebuilds.

**Other Income and Expenses**

*Depreciation and Amortization*

Depreciation and amortization expense was \$236 million for the year ended December 31, 2009 compared to \$211 million and \$180 million for the years ended December 31, 2008 and 2007, respectively. The increases in 2009, 2008 and 2007 related primarily to an increased amount of depreciable assets stemming from our acquisition activities and internal growth projects. Amortization of debt issue costs was \$6 million, \$4 million and \$3 million in 2009, 2008 and 2007, respectively.

Included in depreciation expense for the years ended December 31, 2009, 2008 and 2007 is a net loss of \$1 million, a net gain of \$6 million and a net loss of approximately \$7 million, respectively, recognized upon disposition of certain inactive assets. Also included within depreciation expense for the year ended December 31, 2009 and 2008 is an impairment of less than \$1 million and \$5 million, respectively, for assets taken out of service.

*Interest Expense*

Interest expense was \$224 million for the year ended December 31, 2009, compared to \$196 million and \$162 million for the years ended December 31, 2008 and 2007, respectively. Interest expense is primarily impacted by:

- our weighted average debt balances;
  
- the level and maturity of fixed rate debt and interest rates associated therewith;

- market interest rates and our interest rate hedging activities on floating rate debt; and
- interest capitalized on capital projects.

The following table summarizes selected components of our weighted average debt balances (in millions):

	2009		For the year ended December 31, 2008		2007	
	Total	% of Total	Total	% of Total	Total	% of Total
Fixed rate senior notes (1)	\$ 3,722	95%	\$ 3,028	87%	\$ 2,625	95%
Borrowings under our revolving credit facilities (2)	207	5%	456	13%	150	5%
<b>Total</b>	<b>\$ 3,929</b>		<b>\$ 3,484</b>		<b>\$ 2,775</b>	

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

(2) Excludes borrowings under our senior secured hedged inventory facility and the short-term portion of our senior unsecured revolving credit facility, as the associated interest expense is recorded in Purchases and related costs on our consolidated income statement.

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The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2009 and 2008 (in millions, except for percentages):

	\$	Average LIBOR Rate	Weighted Average Interest Rate (1)
Interest expense for the year ended December 31, 2007	\$ 162	5.2%	6.3%
Impact of issuance of senior notes (2)	27		
Impact of increased borrowings under credit facilities (3)	5		
Impact of increased capitalized interest	(3)		
Other	5		
Interest expense for the year ended December 31, 2008	\$ 196	2.7%	5.9%
Impact of retirement of senior notes (4)	(7)		
Impact of issuance of senior notes (5)	53		
Impact of decreased borrowings under credit facilities (3)	(15)		
Impact of decreased capitalized interest	2		
Other	(5)		
Interest expense for the year ended December 31, 2009	\$ 224	0.3%	6.0%

(1) Excludes commitment and other fees.

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

(3) The change primarily reflects varying borrowing requirements for inventory-related borrowings and other working capital items and changes in LIBOR rates. As further discussed below, during 2009 we utilized a portion of our \$500 million 4.25% senior notes due 2012 to fund our hedged inventory requirements. Therefore, we were able to reduce our short-term debt borrowing since such activities were not solely funded on our credit facilities.

(4) In August 2009, our outstanding \$175 million 4.75% senior notes due 2009 matured and were paid. In October 2009, we redeemed our outstanding \$250 million 7.13% senior notes due 2014.

(5) In April, July and September 2009 we completed the issuances of \$350 million of 8.75% senior notes due 2019, \$500 million of 4.25% senior notes due 2012 and \$500 million of 5.75% senior notes due 2020, respectively. A fluctuating portion of the 4.25% senior notes due 2012 is utilized to fund hedged inventory and would be classified as short-term debt if such activities were funded through our credit facilities. Interest costs attributable to borrowings for inventory stored in a contango market are included in Purchases and related costs in our supply and logistics segment profits as we consider interest on these borrowings a direct cost to storing the inventory. The costs applicable to the portion of the \$500 million of 4.25% senior notes that was recognized within purchases and related costs was approximately \$1 million for the year ended December 31, 2009.

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In April 2008, we completed the issuance of our \$600 million 6.5% senior notes due 2018. Therefore, these senior notes were outstanding for approximately eight months of the year compared to twelve months during 2009.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our supply and logistics segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately \$11 million, \$21 million and \$44 million for the years ended December 31, 2009, 2008 and 2007, respectively.

### *Other Income, Net*

Other income, net for the year ended December 31, 2009, primarily included (i) a net gain of approximately \$9 million recognized in connection with the PNGS acquisition (see Note 3 to our Consolidated Financial Statements for further discussion), (ii) a net gain of approximately \$11 million related to the foreign currency revaluation of a CAD-denominated interest receivable associated with an intercompany note and the impact of related foreign currency hedges, and (iii) a loss of approximately \$4 million recognized in conjunction with the early redemption of our \$250 million 7.13% senior notes.

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

### *Income Tax Expense*

Our income tax expense decreased by \$2 million from \$8 million in 2008 to \$6 million in 2009 as a result of a decrease of Canadian taxable income.

Excluding the \$10 million impact of the initial adoption of the revised Canadian tax laws in 2007, our income tax expense increased by \$2 million in 2008 compared to 2007 primarily due to the Rainbow acquisition. Income tax expense was \$16 million for the year ended December 31, 2007 primarily due to revised rules on Canadian taxation on certain flow-through entities and the introduction of the Texas margin tax. See Note 7 to our Consolidated Financial Statements for further discussion.

### **Outlook**

During 2008 and 2009, worldwide financial markets were extremely volatile and the global economy substantially weakened. The U.S. government and governments around the world took significant actions in response, including an attempt to provide liquidity and stability to the financial markets by providing government assistance to some of the largest financial institutions in the world. Although it appears that these collective actions have been successful in stabilizing the financial markets, we continue to maintain a cautious outlook for the overall economic environment. Certain recent data signal improvements in the health of the



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economy have started to occur, while other data indicate that we have yet to begin a sustainable recovery. For example, one indicator of the strength and velocity of the economy that also has an influence on our business is energy consumption. Based on data available through early 2010, U.S. demand for petroleum has declined by approximately 10% from levels experienced during the 2005 to 2007 time period and natural gas demand has declined approximately 2% to 3% relative to 2008.

Although we expect that the U.S. economy will ultimately rebound and energy demand will return to a growth profile, these conflicting signals lead us to believe that significant uncertainty remains regarding the timing of the recovery, which translates into potential near-term risks for the energy sector. We will not be unaffected by challenging economic and capital markets conditions, however, our business strategy is designed to manage a volatile environment, and we believe that our asset base strategically positions us to benefit from certain of these developments. However, there can be no assurance that we will not be negatively affected by this volatility or the challenging capital markets conditions, or that our acquisition and expansion efforts will be successful. See Item 1A. Risk Factors - Risks Related to Our Business.

**Liquidity and Capital Resources**

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At December 31, 2009, we had approximately \$1.0 billion of liquidity available to meet our ongoing operational, investing and finance needs as noted below (in millions):

	As of	
	December 31, 2009	
Availability under our senior unsecured revolving credit facility	\$	751
Availability under our senior secured hedged inventory facility		200
Cash and cash equivalents		25
Total	\$	976

At December 31, 2009, we had a working capital deficit of approximately \$124 million. We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a material adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. Risk Factors for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

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**Cash Flow from Operations**

The primary drivers of cash flow from our operations are (i) the collection of amounts related to the sale of crude oil and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services, and (ii) the payment of amounts related to the purchase of crude oil and other products and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except (i) in the months that we store the purchased crude oil and hedge it by selling it forward for delivery in a subsequent month because of contango market conditions or (ii) in months in which we increase our share of linefill in third party pipelines. In addition, our cash flow from operations may be impacted by the timing of settlement of our derivative activities. Gains and losses from settled instruments that qualify as effective cash flow hedges are deferred in AOCI, but may impact operating cash flow in the period settled.

The storage of crude oil in periods of a contango market, when the price of crude oil for future deliveries is higher than current prices, can have a material impact on our cash flows from operating activities. In the month we pay for the stored crude oil, we borrow under our credit facilities (or pay from cash on hand) to pay for the crude oil, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, but to a lesser extent, the level of LPG and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it and we do not rely on borrowings under our credit facilities to pay for the crude oil. During such market conditions, our accounts payable and accounts receivable generally move in tandem as we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. In periods during which we build inventory or linefill, regardless of market structure, we may rely on our credit facilities to pay for the inventory or linefill.

Our cash flow from operations was positively impacted by cash generated by our recurring operations. Our cash flow from operations can be significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During 2009, we increased the amount of our inventory. The increase in inventory was due to both increased volumes and an increase in prices and was primarily related to our crude oil contango market storage activities. The net increased levels of inventory were financed through borrowings under our credit facilities and senior note issuances resulting in a negative impact to our operating cash flow for the period.

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

**Credit Facilities and Long-Term Debt**



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At December 31, 2009, we had approximately \$751 million of available borrowing capacity under our \$1.6 billion committed revolving credit facility. Of the capacity we utilized at December 31, 2009, approximately \$76 million was associated with outstanding letters of credit and the remainder was borrowed. The majority of these borrowings relate to funding short term inventory purchases of LPG and crude oil. This credit facility, among other things, has a maturity date of July 2012, contains no Material Adverse Change language and can be expanded to \$2.0 billion, subject to additional lender commitments. See Note 4 to our Consolidated Financial Statements.

At December 31, 2009, we had approximately \$200 million of availability under our \$500 million committed hedged inventory facility. The facility's committed amount may be increased to \$1.2 billion, subject to obtaining additional commitments from lenders. This facility is a committed working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. The facility matures on an annual basis beginning in October 2010.

We also have several issues of senior debt outstanding that total approximately \$4.2 billion, excluding premium or discount, and range in size from \$150 million to \$600 million and mature at various dates through 2037.

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Our credit agreements and the indentures governing our senior notes contain cross-default provisions. A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures. See Note 4 to our Consolidated Financial Statements.

**Equity and Debt Financing Activities**

Our financing activities primarily relate to funding acquisitions and internal capital projects, and short-term working capital and hedged inventory borrowings related to our LPG business and contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

We periodically access the capital markets for both equity and debt financing. As of December 31, 2009, approximately \$2.0 billion of unsold securities remained available under our shelf registration statement declared effective on December 16, 2009. We also have access to a universal shelf registration statement, which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs.

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

2009		2008		2007	
Units	Net Proceeds (1)	Units	Net Proceeds (1)	Units	Net Proceeds (1)
11,040,000	\$ 456	6,900,000	\$ 315	6,296,172	\$ 383

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

*Senior Notes.* During the last three years we completed the sale of senior unsecured notes as summarized in the table below (in millions).

Year	Description	Maturity	Face Value	Net Proceeds(1)
2009	5.75% Senior Notes issued at 99.523% of face value			
	(2)	January 2020	\$ 500	\$ 494
	4.25% Senior Notes issued at 99.802% of face value	September 2012	\$ 500	\$ 497
	8.75% Senior Notes issued at 99.994% of face value	May 2019	\$ 350	\$ 347
2008	6.5% Senior Notes issued at 99.424% of face value	May 2018	\$ 600	\$ 597

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

(2) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, a portion of which was used to fund the cash requirements of the PNGS acquisition (which included repayment of all of PNGS's debt). In addition, we used a portion of the proceeds to redeem all of our outstanding \$250 million 7.13% senior notes due 2014 (in conjunction with the early redemption of these notes, we recognized a loss of approximately \$4 million).

On August 15, 2009, our \$175 million senior notes matured. We utilized cash on hand and available capacity under our credit facilities to retire these senior notes.

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*Credit Facilities.* During the year ended December 31, 2009, we had net borrowings on our revolving credit facility and our hedged inventory facility of approximately \$1 million. During the year ended December 31, 2008, we had net working capital and hedged inventory borrowings of approximately \$90 million. These net borrowings were used primarily for purchases of LPG inventory that was stored. During the year ended December 31, 2007, we had net working capital and hedged inventory repayments of approximately \$54 million. These repayments resulted primarily from sales of crude oil inventory that was stored and subsequently liquidated as we transitioned to backwardated market conditions, partially offset by higher levels of stored LPG inventory. See *Cash Flow from Operations* above.

**Capital Expenditures and Distributions Paid to Our Unitholders and General Partner**

We use cash primarily for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. See *Acquisitions and Internal Growth Projects* for further discussion for such capital expenditures.

*Acquisitions.* The price of the acquisitions includes cash paid, assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year.

*2010 Capital Expansion Projects.* The majority of funding for our 2010 capital program will be provided by revolver borrowings and cash flow in excess of partnership distributions. This will allow us to fund these capital projects without need to access the capital markets for equity or debt. Our 2010 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

<b>Projects</b>	<b>2010</b>
Patoka - Phase III	\$ 24
West Texas gathering lines	18
Bumstead facility upgrade	17
Cushing - Phase VII	17
Cushing - Phase VIII	15
St. James - Phase III	15
Wichita Falls tanks	11
Martinez tanks	9
Other projects, including acquisition related expansion projects (1)	234
	\$ 360

(1) Primarily consists of gas storage construction projects, pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2009.

*Distributions to unitholders and general partner.* We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On February 12, 2010, we paid a quarterly

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distribution of \$0.9275 per limited partner unit. This distribution represented a year-over-year distribution increase of approximately 3.9%. See Note 5 to our Consolidated Financial Statements for details of distributions paid. Also, see Item 5. Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash Distribution Policy for additional discussion on distribution thresholds.

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

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We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are subject to business and operational risks, however, that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

**Contingencies**

See Note 11 to our Consolidated Financial Statements.

**Commitments**

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

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2009 (in millions):

	Total	2010	2011	2012	2013	2014	2015 and Thereafter
Long-term debt and interest payments(1)	\$ 7,150	\$ 66	\$ 260	\$ 260	\$ 950	\$ 472	\$ 5,142
Leases (2)	491	79	62	54	33	23	240
Other long-term liabilities(3)	234	118	25	22	23	3	43
Subtotal	7,875	263	347	336	1,006	498	5,425
Crude oil, LPG and other purchases(4)	5,429	4,201	820	379	16	2	11
Total	\$ 13,304	\$ 4,464	\$ 1,167	\$ 715	\$ 1,022	\$ 500	\$ 5,436

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at December 31, 2009, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for (i) storage, (ii) rights-of-way, (iii) office rent and (iv) trucks used in our gathering activities.

(3) Excludes a non-current liability of approximately \$35 million related to derivative activity included in crude oil and LPG purchases.

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

*Letters of Credit.* In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2009 and 2008, we had outstanding letters of credit of approximately \$76 million and \$51 million, respectively. The change in the value of outstanding letters of credit is impacted primarily by the fluctuation of market prices and the timing of foreign cargo purchases.

#### **Off-Balance Sheet Arrangements**

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

Table of Contents**Investments in Unconsolidated Entities**

We have invested in entities that are not consolidated in our financial statements. Certain of these entities are borrowers under credit facilities. We are neither a co-borrower nor a guarantor under any such facilities. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2009 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
<b>Settoon Towing</b>	Barge Transportation Services	50%	\$ 92	\$	\$ 53
<b>Frontier</b>	Crude Oil Pipeline	22%	\$ 27	\$ 3	\$
<b>Butte</b>	Crude Oil Pipeline	22%	\$ 19	\$ 5	\$

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

We are exposed to various market risks, including volatility in (i) commodity prices for crude oil, refined products, natural gas and LPG, (ii) interest rates and (iii) currency exchange rates. We utilize various derivative instruments to manage such exposure and, in certain circumstances, to realize incremental margin during volatile market conditions. In analyzing our risk management activities, we draw a distinction between enterprise level risks and trading related risks. Enterprise level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the our 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 interest rates, currency exchange rates, NYMEX, ICE and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure our hedging activities address our market risks. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain 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. To hedge the risks discussed above, we engage in risk management activities that we categorize by the risks we are hedging. The following discussion addresses each category of risk.

**Commodity Price Risk**

We use derivative instruments and physical delivery contracts to hedge our exposure to price fluctuations with respect to crude oil, refined products, natural gas and LPG in storage, and anticipated purchases and sales of these commodities. The derivative instruments utilized consist primarily of futures, options and swaps traded on the NYMEX and ICE and in over-the-counter transactions, including swaps and options contracts. Our policy is to purchase only commodity products for which we have a market, and to structure our sales contracts so that price fluctuations for those products do not materially affect the segment profit we earn. We do not acquire and hold futures contracts or physical commodities for the purpose of speculating on price changes, as these activities could expose us to significant losses.



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Although we seek to maintain a position that is substantially balanced within our various commodity purchase and sales activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives are recognized in earnings, and result in greater potential for earnings volatility. This accounting treatment is discussed further in Note 2 to our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2009 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10% price decrease is shown in the table below (in millions):

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	Fair Value	Effect of 10% Price Decrease
<b>Crude oil:</b>		
Futures contracts	\$ 39	\$ 82
Swaps and options contracts	(14)	\$ 27
<b>LPG and other:</b>		
Futures contracts	(13)	
Swaps and options contracts (1)	(16)	\$ (13)
<b>Total Fair Value</b>	<b>\$ (4)</b>	

(1) Amount includes a liability of approximately \$7 million associated with LPG physical contracts not eligible for the normal purchase and normal sale scope exception under FASB guidance.

The fair value of our exchange-traded contracts is based on quoted market prices obtained from the NYMEX or ICE. The fair value of our over-the-counter swaps and options contracts is estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. These quotes are compared to the contract price of the swap, which approximates the gain or loss that would have been realized if the contracts had been closed out at year end. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. The assumptions used in these estimates as well as the source for the estimates are maintained by the independent risk control function. See Note 6 to our Consolidated Financial Statements for further discussion. Price-risk sensitivities were calculated by assuming an across-the-board 10% decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

**Interest Rate Risk**

We use both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities. Therefore, from time to time we use interest rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. All of our senior notes are fixed rate notes and thus not subject to market risk. Substantially all of our variable rate debt at December 31, 2009, approximately \$1.4 billion (including \$300 million of interest rate derivatives that swap fixed rate debt for floating), is short-term debt and is subject to interest rate re-sets, which range from a week to three months. The average interest rate of 1.3% is based upon rates in effect at December 31, 2009. The fair value of our interest rate derivatives is an unrealized gain of approximately \$2 million as of December 31, 2009. A 10% decrease in the forward LIBOR curve as of December 31, 2009 would result in an increase of approximately \$1 million to the fair value of our interest rate derivatives. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates. See Note 6 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

**Currency Exchange Risk**

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks associated with our exposure to fluctuations in the U.S Dollar-to-Canadian Dollar exchange rate. These instruments primarily include

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forward exchange contracts, foreign currency forwards and options. The fair value of these instruments is an unrealized gain of approximately \$1 million as of December 31, 2009. A 10% decrease in the exchange rate (Canadian dollars to U.S. dollars) would result in an increase of approximately \$8 million to the fair value of our foreign currency derivatives. See Note 6 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

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

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

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

None.

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**Item 9A. Controls and Procedures**

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

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report. Based on this review, our Chief Executive Officer and Chief Financial Officer have found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

***Changes in Internal Control over Financial Reporting***

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

***Certifications***

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

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2009. See Management's Report on Internal Control Over Financial Reporting on page F-2.

**Item 9B. Other Information**

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There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2009 that has not previously been reported.

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**PART III**

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

**Partnership Management and Governance**

As with many publicly traded partnerships, we do not directly have officers, directors or employees. Our operations and activities are managed by Plains All American GP LLC ( GP LLC ), which employs our management and operational personnel (other than our Canadian personnel, who are employed by PMC (Nova Scotia) Company). GP LLC is the general partner of Plains AAP, L.P. ( AAP LP ), which is the sole member of PAA GP LLC, our general partner. References to our general partner, as the context requires, include any or all of GP LLC, AAP LP and PAA GP LLC. References to our officers, directors and employees are references to the officers, directors and employees of GP LLC (or, in the case of our Canadian operations, PMC (Nova Scotia) Company).

Our general partner manages our operations and activities. Unitholders are limited partners and do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders, as limited by our partnership agreement. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Our general partner has the sole discretion to incur indebtedness or other obligations on our behalf on a non-recourse basis to the general partner. Our general partner has in the past exercised such discretion, in most instances involving payment liability, and intends to exercise such discretion in the future.

Our partnership agreement provides that our general partner will manage and operate us and that unitholders, unlike holders of common stock in a corporation, will have only limited voting rights on matters affecting our business or governance. The corporate governance of GP LLC is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement. References to our Board of Directors mean the board of directors of GP LLC, which consists of eight directors elected by the members of GP LLC, and not by our unitholders. Under the Fourth Amended and Restated Limited Liability Company Agreement of GP LLC (the GP LLC Agreement ), two of the members of GP LLC have the right to designate one director each, and our CEO is a director by virtue of holding the office. The remaining five seats are elected, and may be removed, by a majority of the membership interest. Directors filling three of these five at large seats must be independent. Under our current ownership profile, any member that accumulates an interest greater than 25% and does not otherwise have a designation right may designate a director. In the event a member of GP LLC ceases to have the right to designate a director, the individual designated by such member is automatically removed as a director. One of the members of GP LLC, a wholly owned subsidiary of Occidental Petroleum Corporation ( Oxy ), has the right to designate an individual to attend Board meetings in an observer capacity. Under certain circumstances involving changes in senior-most management, Oxy will have the right to designate a director to serve on the Board and the authorized number of Board members will be expanded to a total of nine.

In connection with a transaction in which it increased its ownership to greater than 50%, Vulcan Energy entered into an agreement with GP LLC pursuant to which Vulcan Energy has agreed to restrict certain of its voting rights to help preserve a balanced board. Vulcan Energy has agreed that, with respect to any action taken involving the election or removal of an independent director serving on our audit committee, Vulcan Energy will vote all of its interest in excess of 49.9% in the same way and proportionate to the votes of all membership interests other than Vulcan Energy s. Without the voting rights agreement, Vulcan Energy s ownership interest would, in effect, allow Vulcan Energy unilaterally to elect the Vulcan Energy designee and the five at large seats (subject to the requirement that three of the at large directors meet the independence requirements set forth in the GP LLC Agreement, our partnership agreement, NYSE listing standards and SEC regulations). Vulcan Energy has the right at any time to give notice of termination of the voting rights agreement. The time between notice and termination depends on the

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circumstances, but would never be longer than one year. In connection with Vulcan Energy's entry into the voting rights agreement, Messrs. Armstrong and Pefanis entered into waivers of the change in control provisions of their employment agreements, which otherwise would have been triggered by the transaction in which Vulcan Energy obtained the additional interest. These waivers were contingent upon Vulcan's execution of the voting rights agreement, and will terminate upon any breach or termination by Vulcan Energy of, or notice of termination under, the voting rights agreement. See Item 11. Executive Compensation Employment Contracts and Potential Payments upon Termination or Change-in-Control.

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Another member of GP LLC, Lynx Holdings I, LLC, has also agreed to certain restrictions on its voting rights with respect to its approximate 1.4% interest in GP LLC and AAP LP. The Lynx voting rights agreement requires Lynx to vote its membership interest (in the context of the election or the removal of an independent director serving on our audit committee) in the same way and proportionate to the votes of the other membership interests (excluding Vulcan s and Lynx s). Lynx has the right to terminate its voting rights agreement at any time upon termination of the Vulcan voting rights agreement or the sale or transfer of all of its interest in the general partner to an unaffiliated third party.

**Board Leadership Structure and Role in Risk Oversight**

Our CEO also serves as Chairman of the Board. The board has no policy with respect to the separation of the offices of chairman and CEO; rather, that relationship is currently defined and governed by the GP LLC Agreement and the employment agreement with the CEO, which require coincidence of the offices. We do not have a lead independent director. The chairmanship of non-management executive sessions of the board rotates among the non-management directors, sequenced alphabetically by last name. Directors of GP LLC are designated or elected by the members of GP LLC. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

The management of enterprise level risk (ELR) may be defined as the process of identification, management and monitoring of events that present opportunities and risks with respect to creation of value for our unitholders. The board has delegated to management the primary responsibility for ELR management, while the board has retained responsibility for oversight of management in that regard. Management offers an enterprise-level risk assessment to the Board at least once every year.

**Non-Management Executive Sessions and Shareholder Communications**

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

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

**Independence Determinations and Audit Committee**

Because we are a limited partnership, the listing standards of the NYSE do not require that we or our general partner have a majority of independent directors or a nominating or compensation committee of the board of directors. We are, however, required to have an audit committee consisting of at least three members, all of whom are required to be independent as defined by the NYSE.



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

We have an audit committee that reviews our external financial reporting, engages our independent auditors and reviews the adequacy of our internal accounting controls. The charter of our audit committee is available on our website. See [Meetings and Other Information](#) for information on how to access or obtain copies of this charter. The board of directors has determined that each member of our audit committee (Everardo Goyanes, Arthur L. Smith and J. Taft Symonds) is (i) independent under applicable NYSE rules and (ii) an Audit Committee Financial Expert, as that term is defined in Item 407 of Regulation S-K.

In determining the independence of the members of our audit committee, the board of directors considered the relationships described below:

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*Everardo Goyanes*, the chairman of our audit committee, is Chairman of Liberty Natural Resources for Liberty Mutual Insurance Company, which is the parent of Liberty Energy Holdings, LLC ( LEH ). LEH makes investments in producing properties, from some of which Plains Marketing, L.P. buys the production. LEH does not operate the properties in which it invests. Plains Marketing pays the same amount per barrel to LEH that it pays to other interest owners in the properties. In 2009, the amount paid to LEH by Plains Marketing was approximately \$0.2 million (net of severance taxes). The board has determined that the transactions with LEH do not compromise Mr. Goyanes' independence.

*Arthur L. Smith*, a member of our audit committee, is a director of Pioneer Natural Resources GP LLC, the general partner of Pioneer Southwest Energy Partners, L.P. ( PSE ). PSE is a subsidiary of Pioneer Natural Resources Company ( Pioneer ). Pioneer and its affiliates (including PSE) own crude oil producing properties in the Permian Basin of Texas and New Mexico, from which Plains Marketing gathers and markets the petroleum production. Mr. Smith is not an officer of PSE or Pioneer and does not participate in operational decision making. In 2009, the amount paid to Pioneer and its affiliates for petroleum gathered and marketed by Plains Marketing was approximately \$302 million. The board has determined that the transactions with PSE and Pioneer do not compromise Mr. Smith's independence.

*J. Taft Symonds*, a member of our audit committee, has no relationships with either GP LLC or us, other than as a director and unitholder.

For additional information regarding the experience and qualifications of our directors, please read the biographical descriptions under Directors, Executive Officers and Other Officers below.

**Compensation Committee**

We have a compensation committee that reviews and makes recommendations to the board regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. The charter of our compensation committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The compensation committee currently consists of Geoff McKay, Gary R. Petersen and Robert V. Sinnott. Under applicable stock exchange rules, none of the members of our compensation committee is required to be independent. The compensation committee has the sole authority to retain any compensation consultants to be used to assist the committee, but did not retain any consultants in 2009. Similarly, the compensation committee has not delegated any of its authority to subcommittees. The compensation committee has delegated limited authority to the CEO to administer our long-term incentive plans with respect to employees other than executive officers.

**Governance and Other Committees**

We also have a governance committee that periodically reviews our governance guidelines. The charter of our governance committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The governance committee currently consists of Messrs. Smith and Symonds, each of whom is independent under the NYSE's listing standards. As a limited partnership, we are not required by the listing standards of the NYSE to have a nominating committee. As discussed above, two of the owners of our general partner each have the right to appoint a director, and Mr. Armstrong is a director by virtue of his office. In the event of a vacancy in the three required independent director seats, the governance committee will assist in identifying and screening potential candidates. Upon request of the owners of the general partner, the governance committee is also available to assist in identifying and screening potential candidates for the currently vacant at large seat. The governance committee will base its recommendations on an assessment of the skills,

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experience and characteristics of the candidate in the context of the needs of the board. The governance committee does not have a policy with regard to the consideration of diversity in identifying director nominees; therefore, diversity may or may not be considered in connection with the assessment process. As a minimum requirement for the three required independent board seats, any candidate must be independent and qualify for service on the audit committee under applicable SEC and NYSE rules, the GP LLC Agreement and our partnership agreement.

In addition, our partnership agreement provides for the establishment or activation of a conflicts committee as circumstances warrant to review conflicts of interest between us and our general partner or the owners of our general partner. Such a committee will typically consist of a minimum of two members, none of whom can be

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officers or employees of our general partner or directors, officers or employees of its affiliates or owners of the general partner interest. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Review, Approval or Ratification of Transactions with Related Persons.

**Meetings and Other Information**

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

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

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

**Audit Committee Report**

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

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

The Partnership's independent registered public accounting firm, PricewaterhouseCoopers LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with accounting principles generally accepted in the United States of America. The audit committee reviewed with PricewaterhouseCoopers LLP the firm's judgment as to the quality, not just the acceptability, of the Partnership's accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing

standards.

The audit committee discussed with PricewaterhouseCoopers LLP the matters required to be discussed by Statement of Auditing Standards No. 61, as amended, as adopted by the Public Company Accounting Oversight Board. The committee received written disclosures and the letter from PricewaterhouseCoopers LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding PricewaterhouseCoopers LLP's communications with the audit committee concerning independence, and has discussed with PricewaterhouseCoopers LLP its independence from management and the Partnership.

Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2009 for filing with the SEC.

Table of ContentsEverardo Goyanes, *Chairman*

Arthur L. Smith

J. Taft Symonds

**Directors, Executive Officers and Other Officers**

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

<b>Name</b>	<b>Age (as of 12/31/09)</b>	<b>Position(1)</b>
Greg L. Armstrong*(2)	51	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	52	President and Chief Operating Officer
Phillip D. Kramer*	53	Executive Vice President
W. David Duckett*	54	President PMC (Nova Scotia) Company
Mark J. Gorman*	55	Senior Vice President Operations and Business Development
Alfred A. Lindseth	40	Senior Vice President Technology, Process & Risk Management
Al Swanson*	45	Senior Vice President and Chief Financial Officer
John P. vonBerg*	55	Senior Vice President Commercial Activities
Stephen L. Bart	49	Vice President Operations of PMC (Nova Scotia) Company
Samuel N. Brown	53	Vice President Pipeline Business Development
David Craig	52	Executive Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Ralph R. Cross	54	Vice President Corporate Development and Transportation Services of PMC (Nova Scotia) Company
A. Patrick Diamond	37	Vice President
Lawrence J. Dreyfuss	55	Vice President, General Counsel Commercial & Litigation and Assistant Secretary
Roger D. Everett	64	Vice President Human Resources
James B. Fryfogle	58	Vice President Refinery Supply
M.D. (Mike) Hallahan	49	Vice President Crude Oil of PMC (Nova Scotia) Company
Bill Harradence	56	Vice President Human Resources of PMC (Nova Scotia) Company
Jim G. Hester	50	Vice President Acquisitions
John Keffer	50	Vice President Terminals
Charles Kingswell-Smith	58	Vice President and Treasurer
Gregg McClement	41	Vice President Business Development LPG of PMC (Nova Scotia) Company
Mike Mikuska	41	Vice President Business Development of PMC (Nova Scotia) Company
Tim Moore*	52	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	52	Vice President Engineering
John F. Russell	61	Vice President West Coast Projects
Robert M. Sanford	60	Vice President Lease Supply
Tina L. Summers*	40	Vice President Accounting and Chief Accounting Officer
Troy E. Valenzuela	48	Vice President Environmental, Health and Safety

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Sandi Wingert	39	Vice President Accounting of PMC (Nova Scotia) Company
David E. Wright	64	Vice President
Ron F. Wunder	41	Vice President LPG of PMC (Nova Scotia) Company
Everardo Goyanes	65	Director and Member of Audit** Committee
Geoff McKay(2)	42	Director and Member of Compensation Committee
Gary R. Petersen	63	Director and Member of Compensation Committee
Robert V. Sinnott(2)	60	Director and Member of Compensation** Committee
Arthur L. Smith	57	Director and Member of Audit and Governance** Committees
J. Taft Symonds	70	Director and Member of Audit and Governance Committees
Christopher M. Temple	42	Director

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

\*\* Indicates chairman of committee.

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

(2) The GP LLC Agreement specifies that the Chief Executive Officer of the general partner will be a member of the board of directors. The GP LLC Agreement also provides that two of the owners of our general partner each have the right to appoint a member of our board of directors. Mr. McKay has been appointed by Vulcan Energy Corporation, of which he is Chairman of the Board. Mr. Sinnott has been appointed by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is President. The remaining directors were elected by a majority of the membership interest. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest.

*Greg L. Armstrong* has served as Chairman of the Board and Chief Executive Officer since our formation in 1998. He has also served as a director of our general partner or former general partner since our formation. In addition, he was President, Chief Executive Officer and director of Plains Resources Inc. from 1992 to May 2001. He previously served Plains Resources as: President and Chief Operating Officer from October to December 1992; Executive Vice President and Chief Financial Officer from June to October 1992; Senior Vice President and Chief Financial Officer from 1991 to 1992; Vice President and Chief Financial Officer from 1984 to 1991; Corporate Secretary from 1981 to 1988; and Treasurer from 1984 to 1987. Mr. Armstrong is also a director of National Oilwell Varco, Inc. and PNGS GP LLC, the general partner of PAA Natural Gas Storage, L.P. Mr. Armstrong previously served as a director of BreitBurn Energy Partners, L.P.

*Harry N. Pefanis* has served as President and Chief Operating Officer since our formation in 1998. He was also a director of our former general partner. In addition, he was Executive Vice President Midstream of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as: Senior Vice President from February 1996 until May 1998; Vice President Products Marketing from 1988 to February 1996; Manager of Products Marketing from 1987 to 1988; and Special Assistant for Corporate Planning from 1983 to 1987. Mr. Pefanis was also President of several former midstream subsidiaries of Plains Resources until our formation. Mr. Pefanis is also a director of PNGS GP LLC and Settoon Towing.

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*Phillip D. Kramer* has served as Executive Vice President since November 2008 and previously served as Executive Vice President and Chief Financial Officer from our formation in 1998 until November 2008. In addition, he was Executive Vice President and Chief Financial Officer of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as: Senior Vice President and Chief Financial Officer from May 1997 until May 1998; Vice President and Chief Financial Officer from 1992 to 1997; Vice President from 1988 to 1992; Treasurer from 1987 to 2001; and Controller from 1983 to 1987.



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*W. David Duckett* has served as President of PMC (Nova Scotia) Company since June 2003, and Executive Vice President of PMC (Nova Scotia) Company from July 2001 to June 2003. Mr. Duckett was with CANPET Energy Group Inc. ( CANPET ) from 1985 to 2001, where he served in various capacities, including most recently as President, Chief Executive Officer and Chairman of the Board.

*Mark J. Gorman* has served as Senior Vice President Operations and Business Development since August 2008. He previously served as Vice President from November 2006 until August 2008. Prior to joining Plains, he was with Genesis Energy in differing capacities as a Director, President and CEO, and Executive Vice President and COO from 1996 through August 2006. From 1992 to 1996, he served as a President for Howell Crude Oil Company. Mr. Gorman began his career with Marathon Oil Company, spending 13 years in various disciplines. Mr. Gorman is also a director of Settoon Towing, Butte, Frontier and SLC Pipeline.

*Alfred A. Lindseth* has served as Senior Vice President Technology, Process & Risk Management since June 2003 and as Vice President Administration from March 2001 to June 2003. He served as Risk Manager from March 2000 to March 2001. Mr. Lindseth previously served PricewaterhouseCoopers LLP in its Financial Risk Management Practice section as a Consultant from 1997 to 1999 and as Principal Consultant from 1999 to March 2000. He also served GSC Energy, an energy risk management brokerage and consulting firm, as Manager of its Oil & Gas Hedging Program from 1995 to 1996 and as Director of Research and Trading from 1996 to 1997.

*Al Swanson* has served as Senior Vice President and Chief Financial Officer since November 2008. He previously served as Senior Vice President Finance from August 2008 until November 2008 and as Senior Vice President Finance and Treasurer from August 2007 until August 2008. He served as Vice President Finance and Treasurer from August 2005 to August 2007, as Vice President and Treasurer from February 2004 to August 2005 and as Treasurer from May 2001 to February 2004. In addition, he held finance related positions at Plains Resources including Treasurer from February 2001 to May 2001 and Director of Treasury from November 2000 to February 2001. Prior to joining Plains Resources, he served as Treasurer of Santa Fe Snyder Corporation from 1999 to October 2000 and in various capacities at Snyder Oil Corporation including Director of Corporate Finance from 1998, Controller SOCO Offshore, Inc. from 1997, and Accounting Manager from 1992. Mr. Swanson began his career with Apache Corporation in 1986 serving in internal audit and accounting. Mr. Swanson is also a director of PNGS GP LLC.

*John P. vonBerg* has served as Senior Vice President Commercial Activities since August 2008. Previously he served as Vice President Commercial Activities from August 2007 until August 2008 and as Vice President Trading from May 2003 until August 2007. He served as Director of these activities from January 2002 until May 2003. Prior to joining us in January 2002, he was with Genesis Energy in differing capacities as a Director, Vice Chairman, President and CEO from 1996 through 2001, and from 1993 to 1996 he served as a Vice President and a Crude Oil Manager for Phibro Energy USA. Mr. vonBerg began his career with Marathon Oil Company, spending 13 years in various disciplines.

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

*Samuel N. Brown* has served as Vice President Pipeline Business Development since October 2009. Prior to joining PAA, Mr. Brown served TEPPCO for over 10 years, most recently as Vice President Commercial Downstream and previously as Vice President Pipeline Marketing and Business Development for the Upstream segment. Prior to joining TEPPCO, Mr. Brown served Duke Energy Transport and Trading Company.

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

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*Ralph R. Cross* has served as Vice President Corporate Development and Transportation Services of PMC (Nova Scotia) Company since July 2001. Mr. Cross was previously with CANPET since 1992, where he served in various capacities, including most recently as Vice President of Business Development.

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

*Lawrence J. Dreyfuss* has served as Vice President, General Counsel Commercial & Litigation and Assistant Secretary since August 2006. Mr. Dreyfuss was Vice President, Associate General Counsel and Assistant Secretary of our general partner from February 2004 to August 2006 and Associate General Counsel and Assistant Secretary of our general partner from June 2001 to February 2004 and held a senior management position in the Law Department since May 1999. In addition, he was a Vice President of Scurlock Permian LLC from 1987 to 1999.

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

*James B. Fryfogle* has served as Vice President Refinery Supply since March 2005. He served as Vice President Lease Operations from July 2004 until March 2005. Prior to joining us in January 2004, Mr. Fryfogle served as Manager of Crude Supply and Trading for Marathon Ashland Petroleum. Mr. Fryfogle had held numerous positions of increasing responsibility with Marathon Ashland Petroleum or its affiliates or predecessors since 1975.

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

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

*Jim G. Hester* has served as Vice President Acquisitions since March 2002. Prior to joining us, Mr. Hester was Senior Vice President Special Projects of Plains Resources. From May 2001 to December 2001, he was Senior Vice President Operations for Plains Resources. From May 1999 to May 2001, he was Vice President Business Development and Acquisitions of Plains Resources. He was Manager of Business Development and Acquisitions of Plains Resources from 1997 to May 1999, Manager of Corporate Development from 1995 to 1997 and Manager of Special Projects from 1993 to 1995. He was Assistant Controller from 1991 to 1993, Accounting Manager from 1990 to 1991 and Revenue Accounting

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Supervisor from 1988 to 1990.

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

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

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

*Gregg McClement* has served as Vice President Business Development LPG of PMC (Nova Scotia) Company since December 2009. Mr. McClement has been with PMC and its predecessor CANPET since 2001. He previously held numerous senior management roles in the transportation industry with companies such as B.C. Rail and Union Pacific Railway.

*Tim Moore* has served as Vice President, General Counsel and Secretary since May 2000. In addition, he was Vice President, General Counsel and Secretary of Plains Resources from May 2000 to May 2001. Prior to joining Plains Resources, he served in various positions, including General Counsel Corporate, with TransTexas Gas Corporation from 1994 to 2000. He previously was a corporate attorney with the Houston office of Weil, Gotshal & Manges LLP. Mr. Moore also has seven years of energy industry experience as a petroleum geologist.

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

*John F. Russell* has served as Vice President West Coast Projects since August 2007. He served as Vice President Pipeline Operations from July 2004 to August 2007. Prior to joining us, Mr. Russell served as Vice President of Business Development & Joint Interest for ExxonMobil Pipeline Company. Mr. Russell had held numerous positions of increasing responsibility with ExxonMobil Pipeline Company or its affiliates or predecessors since 1974.

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

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

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*Troy E. Valenzuela* has served as Vice President Environmental, Health and Safety, or EH&S, since July 2002, and has had oversight responsibility for the environmental, safety and regulatory compliance efforts of us and our predecessors since 1992. He was Director of EH&S with Plains Resources from January 1996 to June 2002, and Manager of EH&S from July 1992 to December 1995. Prior to his time with Plains Resources, Mr. Valenzuela spent seven years with Chevron USA Production Company in various EH&S roles.

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

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*David E. Wright* has served as Vice President since November 2006. Prior to joining Plains, he served as Executive Vice President, Corporate Development for Pacific Energy Partners, L.P. from February 2005 and as Vice President, Corporate Development and Marketing from December 2001. Mr. Wright also served as Vice President, Distribution West for Tosco Refining Company from March 1997 to June 2001, and as Vice President, Pipelines for GATX Terminals Corporation from October 1995 to March 1997.

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

*Everardo Goyanes* has served as a director of our general partner or former general partner since May 1999. Mr. Goyanes has been Chairman of Liberty Natural Resources since April 2009. From May 2000 to April 2009, he was President and Chief Executive Officer of Liberty Energy Holdings, LLC (an energy investment firm). From 1999 to May 2000, he was a financial consultant specializing in natural resources. From 1989 to 1999, he was Managing Director of the Natural Resources Group of ING Barings Furman Selz (a banking firm). He was a financial consultant from 1987 to 1989 and was Vice President Finance of Forest Oil Corporation from 1983 to 1987. From 1967 to 1982, Mr. Goyanes served in various financial and management capacities at Chase Bank, where his major emphasis was international and corporate finance to large independent and major oil companies. Mr. Goyanes received a BA in Economics from Cornell University and a Master's degree in Finance (honors) from Babson Institute. The Board of Directors has determined that Mr. Goyanes is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. Mr. Goyanes' qualifications as an Audit Committee Financial Expert are supplemented by extensive experience comprising direct involvement in the energy sector over a span of more than 30 years. We believe that this experience, coupled with the leadership qualities demonstrated by his executive background bring important experience and skill to the Board.

*Geoff McKay* has served as a director of our general partner since February 2010. Mr. McKay is a Managing Director at Vulcan Capital, the private investment group of Vulcan Inc. He also sits on the boards of Vulcan Energy GP Holdings Inc. and Vulcan Energy Corporation. From March 2000 until joining Vulcan in May 2007, Mr. McKay worked for Forstmann Little & Co., a New York based private equity firm, serving as a general partner from January 2004 to March 2007. During his tenure at Forstmann Little, Mr. McKay was involved with the acquisition and oversight, and served on the boards of directors, of IMG Worldwide, 24 Hour Fitness and ENK International. From 1997 until 2000, he was an investment banker with Goldman Sachs in the mergers and acquisitions group. Mr. McKay currently sits on the boards of TowerCo LLC, ICAT Holdings and Silvercrest Asset Management Group. Mr. McKay holds a BA in Economics from the University of Victoria and an MBA from the Wharton School of the University of Pennsylvania. Mr. McKay has been designated to serve on our Board by Vulcan Energy, pursuant to the power granted under our LLC Agreement. We believe that his substantial transactional experience offers a significant knowledge resource as we pursue our acquisition strategy, and that his investment oversight background and service on other boards will lend critical perspective to the Board.

*Gary R. Petersen* has served as a director of our general partner since June 2001. Mr. Petersen is Senior Managing Director of EnCap Investments L.P., an investment management firm which he co-founded in 1988. He is also a director of EV Energy Partners, L.P. He had previously served as Senior Vice President and Manager of the Corporate Finance Division of the Energy Banking Group for RepublicBank Corporation. Prior to his position at RepublicBank, he was Executive Vice President and a member of the Board of Directors of Nicklos Oil & Gas Company from 1979 to 1984. He served from 1970 to 1971 in the U.S. Army as a First Lieutenant in the Finance Corps and as an Army Officer in the Army Security Agency. Mr. Petersen holds BBA and MBA degrees from Texas Tech University. The Board of Directors has determined that Mr. Petersen is independent under applicable NYSE rules. Mr. Petersen has been involved in the energy sector for a period of more than 30 years, garnering extensive knowledge of the energy sectors' various cycles, as well as the current market and industry knowledge that comes with management of approximately \$7 billion of energy-related investments. In tandem with the leadership qualities evidenced by his executive background, we believe that Mr. Petersen brings numerous valuable attributes to the Board.

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



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Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992. Mr. Sinnott received a BA from the University of Virginia and an MBA from Harvard. Mr. Sinnott's extensive investment management background includes his current role of managing approximately \$6 billion of energy-related investments. Coupled with his direct involvement in the energy sector, spanning more than 30 years, the breadth of his current market and industry knowledge is enhanced by the depth of his knowledge of the various cycles in the energy sector. We believe that as a result of his background and knowledge, as well as the attributes of leadership demonstrated by his executive experience, Mr. Sinnott brings substantial experience and skill to the Board.

*Arthur L. Smith* has served as a director of our general partner or former general partner since February 1999. Mr. Smith is President and Managing Member of Triple Double Advisors, LLC, an investment advisory firm focused on the energy industry. Mr. Smith was Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm) from 1984 to 2007. From 1976 to 1984, Mr. Smith was a securities analyst with Argus Research Corp., The First Boston Corporation and Oppenheimer & Co., Inc. Mr. Smith holds the CFA designation. He serves on the board of non-profit Dress for Success Houston and the Board of Visitors for the Nicholas School of the Environment at Duke University. He is a director of Pioneer Natural Resources GP LLC, the general partner of Pioneer Southwest Energy Partners, L.P. Mr. Smith received a BA from Duke University and an MBA from NYU's Stern School of Business. The Board of Directors has determined that Mr. Smith is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. In addition to his qualifications as an Audit Committee Financial Expert, Mr. Smith has more than 30 years of extensive and intensive experience in the energy sector as an oil analyst, prior board member (Parker & Parsley Petroleum Company, Cabot Oil & Gas Corporation, Evergreen Resources, Inc. and the New York Society of Security Analysts) and industry observer. His acute knowledge of the industry and his executive background provide a critical resource and skill set to the Board.

*J. Taft Symonds* has served as a director of our general partner since June 2001. Mr. Symonds is Chairman of the Board of Symonds Investment Company, Inc. (a private investment firm). From 1978 to 2004 he was Chairman of the Board and Chief Financial Officer of Maurice Pincoffs Company, Inc. (an international marketing firm). Mr. Symonds has a background in both investment and commercial banking, including merchant banking in New York, London and Hong Kong with Paine Webber, Robert Fleming Group and Banque de la Societe Financiere Europeenne. He was Chairman of the Houston Arboretum and Nature Center and currently serves as a director of Howard Supply Company LLC and Schilling Robotics LLC. Mr. Symonds previously served as a director of Tetra Technologies Inc. Mr. Symonds received a BA from Stanford University and an MBA from Harvard. The Board of Directors has determined that Mr. Symonds is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. In addition to his qualifications as an Audit Committee Financial Expert, Mr. Symonds has a broad background in both commercial and investment banking, as well as investment management, all with a heavy emphasis on the energy sector. We believe that Mr. Symonds' background offers to the Board a distinct and valuable knowledge base representative of both the capital and physical markets and refined by the leadership qualities evident from his executive experience.

*Christopher M. Temple* has served as a director of our general partner since May 2009. Mr. Temple served as the President of Vulcan Capital, the private investment group of Vulcan Inc., from May 2009 until December 2009 and as Vice President of Vulcan Capital from September 2008 to May 2009. Mr. Temple also sits on the boards of Vulcan Energy GP Holdings Inc., Vulcan Energy Corporation and Charter Communications Inc. Prior to joining Vulcan in September 2008, Mr. Temple served as a managing director at Tailwind Capital LLC from May to August 2008. Prior to joining Tailwind, Mr. Temple was a managing director at Friend Skoler & Co., Inc. from May 2005 to May 2008. From April 1996 to December 2004, Mr. Temple was a partner at Thayer Capital Partners. Additionally, Mr. Temple was a licensed CPA serving clients in the energy sector with KPMG in Houston, Texas. Mr. Temple holds a BBA, magna cum laude, from the University of Texas and an MBA from Harvard. The Board of Directors has determined that Mr. Temple is independent under applicable NYSE rules. Mr. Temple has a broad investment management background across a variety of business sectors, as well as experience in the energy sector. We believe that this background, along with the leadership attributes indicated by his executive experience, provide an important source of insight and perspective to the Board.

**Section 16(a) Beneficial Ownership Reporting Compliance**

Section 16(a) of the Securities Exchange Act of 1934 requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Such reports are accessible on or through our Internet website at <http://www.paalp.com>.

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Based solely upon a review of the copies of Forms 3 and 4 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our executive officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2009, except as follows: Mr. Symonds inadvertently filed a late Form 4 in connection with the purchase by his wife's trust of PAA units on August 25, 2008. The Form 4 was filed on March 27, 2009.

**Item 11. Executive Compensation**

**Compensation Committee Report**

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

In fulfilling its oversight responsibilities, the compensation committee reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on the reviews and discussions referred to above, the compensation committee recommended to the board of directors that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2009 for filing with the SEC.

Robert V. Sinnott, *Chairman*  
Gary R. Petersen  
T. Geoff McKay  
Christopher M. Temple (former member)

**Compensation Committee Interlocks and Insider Participation**

Messrs. McKay, Petersen and Sinnott currently serve on the compensation committee. Messrs. Petersen, Sinnott and Temple served on the compensation committee during 2009. W. Lance Conn, a former director, served on the compensation committee for a portion of 2009. During 2009, none of the members of the committee was an officer or employee of us or any of our subsidiaries, or served as an officer of any company with respect to which any of our executive officers served on such company's board of directors. In addition, none of the members of the compensation committee are former employees of ours or any of our subsidiaries. Mr. Sinnott is associated with Kayne Anderson and its affiliates, with which we have relationships. Mr. McKay is associated, and Messrs. Conn and Temple were formerly associated, with Vulcan Energy and its affiliates, with which we have relationships. See Item 13. Certain Relationships and Related Transactions, and Director Independence.

**Compensation Discussion and Analysis**

**Background**

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

*Objectives*

Since our inception, we have employed a compensation philosophy that emphasizes pay for performance, both on an individual and entity level, and places the majority of each Named Executive Officer's (defined in the Summary Compensation Table below) compensation at risk. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. We believe our pay-for-performance approach aligns the interests of our executive officers with that of our unitholders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance is below expectations. Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our unitholders, and to reward success in

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reaching such goals. We use three primary elements of compensation to fulfill that design – salary, cash bonus and long-term equity incentive awards. Cash bonuses and equity incentives (as opposed to salary) represent the performance driven elements. They are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals' cash bonuses is based on their relative contribution to achieving or exceeding annual goals and the determination of specific individuals' long-term incentive awards is based on their expected contribution in respect of longer term performance objectives. We do not maintain a defined benefit or pension plan for our executive officers as we believe such plans primarily reward longevity and not performance. We provide a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance. In instances considered necessary for the execution of their job responsibilities, we also reimburse certain of our Named Executive Officers and other employees for club dues and similar expenses. We consider these benefits and reimbursements to be typical of other employers, and we do not believe they are distinctive of our compensation program.

*Elements of Compensation*

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

*Cash Bonuses.* Our cash bonuses consist of annual discretionary bonuses in which all of our current domestic Named Executive Officers potentially participate and a formula-based quarterly bonus program in which Mr. vonBerg was eligible to participate in 2009, 2008 and 2007. Mr. Duckett participates in a formula-based quarterly and annual bonus program specific to activities managed by our Canadian personnel.

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

In 2007, the owners of Plains AAP, L.P. authorized the creation of Class B units of Plains AAP, L.P. and authorized GP LLC's compensation committee to issue grants of Class B units to create additional long-term incentives for our management. The entire economic burden of the Class B units is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding.

The Class B units are subject to restrictions on transfer and generally become incrementally earned (entitled to participate in distributions) upon achievement of certain performance thresholds. As of February 12, 2010, approximately 25% of the outstanding Class B units granted prior to 2009 had been earned and none of the Class B units granted in 2009 had been earned.

To encourage retention following achievement of these performance benchmarks, Plains AAP, L.P. retained a call right to purchase any earned Class B units at a discount to fair market value that is exercisable upon the termination of a holder's employment with Plains All American GP LLC and its affiliates (subject to certain exceptions) prior to January 1, 2016. A portion of unvested Class B units will vest (no longer be subject to the call right) upon a change of control. All earned Class B units will also vest if they remain outstanding as of January 1, 2016 or Plains AAP, L.P. elects not to timely exercise its call right. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Our General Partner Class B Units of Plains AAP, L.P.

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***Relation of Compensation Elements to Compensation Objectives***

Our compensation program is designed to motivate, reward and retain our executive officers. Cash bonuses serve as a near-term motivation and reward for achieving the annual goals established at the beginning of each year. Phantom unit awards (and associated DERs) and Class B units provide motivation and reward over both the near-term and long-term for achieving performance thresholds necessary for earning and vesting. The level of annual bonus and phantom unit awards reflect the moderate salary profile and the significant weighting towards performance based, at-risk compensation. Salaries and cash bonuses (particularly quarterly bonuses), as well as currently payable DERs associated with unvested phantom units and earned Class B units subject to Plains AAP, L.P.'s call right, serve as near-term retention tools. Longer-term retention is facilitated by the minimum service periods of up to five years associated with phantom unit awards, the long-term (January 2016) vesting profile of the Class B units and, in the case of certain executives directly involved in activities that generate partnership earnings, annual bonuses that are payable over a three-year period. To facilitate Plains All American GP LLC's compensation committee in reviewing and making recommendations, a compensation tally sheet is prepared by Plains All American GP LLC's CEO and General Counsel and provided to the compensation committee.

We stress performance-based compensation elements to attempt to create a performance-driven environment in which our executive officers are (i) motivated to perform over both the short term and the long term, (ii) appropriately rewarded for their services and (iii) encouraged to remain with us even after meeting long-term performance thresholds in order to meet the minimum service periods and by the potential for rewards yet to come. We believe our compensation philosophy as implemented by application of the three primary compensation elements (i) aligns the interests of our Named Executive Officers with our unitholders, (ii) positions us to achieve our business goals, and (iii) effectively encourages the exercise of sound judgment and risk-taking that is conducive to creating and sustaining long-term value. We believe the processes employed by the compensation committee and the board in applying the elements of compensation (as discussed in more detail below) provide an adequate level of oversight with respect to the degree of risk being taken by management to achieve short-term performance goals. See *Relation of Compensation Policies and Practices to Risk Management*.

We believe our compensation program has been instrumental in our achievement of stated objectives. Over the five-year period ended December 31, 2009, our annual distribution per common unit has grown at a compound annual rate of 8.5% and the total return realized by our unitholders for that period averaged approximately 14.5%. During this period, we have enjoyed a high rate of retention among executive officers.

***Application of Compensation Elements***

***Salary.*** We do not make systematic annual adjustments to the salaries of our Named Executive Officers. Instead, when indicated as a result of adding new senior management members to keep pace with our overall growth, necessary salary adjustments are made to maintain hierarchical relationships between senior management levels and the new senior management members. Since the date of our initial public offering (or date of employment, if later) through December 31, 2009, Messrs. Armstrong and Pefanis have each received one salary adjustment, Mr. Duckett has received small salary adjustments in line with other Canadian personnel, Mr. vonBerg has received one salary adjustment and Mr. Swanson has received four salary adjustments in connection with taking on increasing responsibilities and promotions.

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

At the end of each year, the CEO performs a quantitative and qualitative assessment of our performance relative to our goals. Key quantitative measures include earnings before interest, taxes, depreciation and amortization, excluding items affecting comparability ( adjusted EBITDA ), relative to established guidance, as well as the growth in the annualized quarterly distribution level per common unit relative to annual growth targets. Our primary performance metric is our ability to generate increasing and sustainable cash distributions to our unitholders. Accordingly, although net income and net income per unit are monitored to highlight inconsistencies with primary performance metrics, as is our market performance relative to our MLP peers and major indices, these metrics are considered secondary performance measures. The CEO's written analysis of our performance examines



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our accomplishments, shortfalls and overall performance against opportunity, taking into account controllable and non-controllable factors encountered during the year.

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

These recommendations are discussed with the compensation committee, adjusted as appropriate, and submitted to the board of directors for its review and approval. Similarly, the compensation committee assesses the CEO's contribution toward meeting our goals, and recommends a bonus for the CEO it believes to be commensurate with such contribution. In several instances, the CEO (and more recently the President as well) has requested that the bonus amount recommended by the compensation committee be reduced to maintain a closer relationship to bonuses awarded to the other Named Executive Officers. As a result, the current practice is for the CEO to submit to the compensation committee a preliminary draft of bonus recommendations with the amount for the CEO left blank. In the context of discussing and adjusting bonus amounts for other executives set forth in the preliminary draft, the committee and the CEO reach consensus on the appropriate bonus amount for the CEO. The preliminary draft is then revised to include any changes or adjustments, as well as an amount for the CEO, in the formal submittal to the compensation committee for review and recommendation to the board.

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

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

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*Long-Term Incentive Awards.* We do not make systematic annual phantom unit awards to our Named Executive Officers. Instead, our objective is to time the granting of awards such that as performance thresholds are met for existing awards, additional long-term incentives are created. Thus, performance is rewarded by relatively greater frequency of awards and lack of performance by relatively lesser frequency of awards. Generally, we believe that a grant cycle of approximately three years (and extended time-vesting requirements) provides a balance between a meaningful retention period for us and a visible, reachable reward for the executive officer. Achievement of

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performance targets does not shorten the minimum service period requirement. If top performance targets on outstanding awards are achieved in the early part of this cycle, new awards are granted with higher performance thresholds, and the minimum service periods of the new awards are generally synchronized with the remaining time-vesting requirements of outstanding awards in a manner designed to encourage extended retention of our Named Executive Officers. Accordingly, these new arrangements inherently take into account the value of awards where performance levels have been achieved but have not yet vested due to ongoing service period requirements, but do not take into consideration previous awards that have fully vested.

As an additional means of providing longer-term, performance-based officer incentives that require extended periods of employment to realize the full benefit, in 2007 the owners of Plains AAP, L.P. authorized the creation of Class B units of Plains AAP, L.P., which the compensation committee of GP LLC is authorized to administer. See Elements of Compensation Long-Term Incentives. These Class B units are limited to 200,000 authorized units, of which approximately 165,500 were issued as of December 31, 2009 pursuant to individual restricted units agreements between Plains AAP, L.P. and certain members of management. As of December 31, 2009 our Named Executive Officers held 111,000 of the restricted Class B units. The remaining available Class B units are administered at the discretion of the compensation committee and may be awarded upon advancement, exceptional performance or other change in circumstance of an existing member of management, or upon the addition of a new individual to the management team.

*Application in 2009*

At the beginning of 2009, we established four public goals with paraphrased versions of three of these goals overlapping with three of our five internal goals. As a result, we entered 2009 with six distinct goals for the year.

The four public goals for the year were to:

1. Deliver baseline operating and financial performance in line with guidance;
2. Successfully execute our 2009 capital program and set the stage for continued growth in 2010;
3. Pursue an average of \$200 to \$300 million of strategic and accretive acquisitions; and
4. Prudently manage our capital resources and preserve our strong capitalization and liquidity.

Our two internal qualitative goals included (i) the continued implementation and expansion of our asset integrity management program with respect to assets not yet covered or only partially covered by regulatory mandate and improvement of our safety performance, and (ii) maintaining and improving communication throughout the organization.

In general, we substantially met or exceeded these six goals.

With respect to our four public goals:

1. Excluding the benefit of unforecasted acquisitions completed during the year, our adjusted EBITDA exceeded the high end of our original guidance for 2009;

2. We began the year with a \$295 million capital program that was expanded during the year to \$380 million. As capital markets improved throughout the year, new projects were added that exceeded our threshold return criteria or were added as a result of acquisitions made during the year. Projects were generally completed timely and cost-effectively;

3. We completed the acquisition of the remaining 50% interest in PNGS for an aggregate purchase price of \$215 million. We also completed six other acquisitions for aggregate consideration of approximately \$180 million, which primarily consisted of pipeline and storage facilities that complemented our existing asset base and business activities. Our three-year average acquisition expenditures total approximately \$418 million per year; and

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4. During the year, we raised approximately \$1.8 billion in both long-term debt and equity in five different transactions and renewed our \$500 million hedged inventory facility on favorable terms. We ended 2009 with a strong balance sheet, solid credit metrics and approximately \$975 million of committed liquidity.

During 2009, we continued to expand, implement and develop our integrity management and maintained communication throughout the organization. We also increased our annualized distribution rate by 3.6% to \$3.68 per common unit, while generating aggregate annual distribution coverage of over 110%.

For 2009, the elements of compensation were applied as follows:

*Salary.* In February 2009, the annual salary of each of Mr. vonBerg and Mr. Swanson was increased to \$250,000. No other salary adjustments for Named Executive Officers were recommended or made in 2009. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table.

*Cash Bonuses.* Based on the CEO's annual performance review and the individual performance of each of our Named Executive Officers, the compensation committee recommended to the board of directors and the board of directors approved the annual bonuses reflected in the Summary Compensation Table and notes thereto. Such amounts take into account the performance relative to each of the four goals established for 2009; the absence of shortfalls relative to expectations; the level of difficulty associated with achieving such objectives; our relative positioning at the end of the year with respect to future growth and performance; the significant transactions or accomplishments for the period not included in the goals for the year; and our positioning at the end of the year with respect to our targeted credit profile. In the case of Mr. Duckett, the aggregate bonus amount represented 40% of his participation level for the first three fiscal quarters and an annual payment consisting of 60% of his participation for the first three quarters and 100% of his participation for the fourth quarter. For Mr. vonBerg, the aggregate bonus amount represented 40% in annual bonus and 60% in quarterly bonus.

*Long-Term Incentive Awards.* In February 2009, Mr. Swanson was awarded 35,000 phantom units under our LTIP. Such award was related to Mr. Swanson's promotion to Chief Financial Officer in November 2008. There were no other grants of long-term incentive awards to Named Executive Officers in 2009. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table.

The last grant cycle of equity awards to Named Executive Officers occurred in 2007. The performance threshold for vesting in one-third of the 2007 grants has been met, and the second performance threshold is expected to be reached in 2010. Vesting under the 2007 awards is also subject to minimum service periods that extend to May 2011 and May 2012. Any of these phantom units that remain outstanding in May 2014 for which the performance thresholds have not been met will be forfeited. Additionally, the highest and last performance threshold for the 2005 grant cycle has been met, and final vesting of such grants will occur in May 2010.

Consistent with our policy of issuing new grants with extended time-vesting periods when attainment of the performance thresholds of existing grants has occurred or is anticipated in the near term, in February 2010 the board of directors granted awards with a top performance threshold of \$4.20 (annualized) distribution per common unit. These grants are intended to encourage continued growth and fundamental performance that will support future distribution growth. These phantom units will vest in respective one-third increments on the date on which we pay an annualized quarterly distribution of at least \$3.90, \$4.05 and \$4.20 per common unit and the later of the May 2013, May 2014 and May 2015 distribution dates, respectively. Such awards have associated DERs that become payable in one-third increments upon achieving the referenced

performance thresholds, without regard to the minimum service period.

Any of these phantom units that remain outstanding as of the May 2016 distribution date for which the performance thresholds have not been met will be forfeited. Upon vesting, the phantom units are payable on a one-for-one basis in common units. The 2010 awards included grants to our Named Executive Officers as follows: Mr. Armstrong, 180,000; Mr. Pefanis, 120,000; Mr. Swanson, 60,000; Mr. vonBerg, 54,000; and Mr. Duckett, 75,000.

#### ***Other Compensation Related Matters***

*Equity Ownership in PAA.* As of December 31, 2009, our Named Executive Officers collectively owned substantial equity in the Partnership. Although we encourage our Named Executive Officers to acquire and retain ownership in the Partnership, we do not have a policy requiring maintenance of a specified equity ownership level. Our policies prohibit our Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership. As of December 31, 2009, our Named Executive Officers beneficially owned, in the aggregate, approximately 755,711 of our common units (excluding any unvested equity awards), an approximately 2.4% indirect ownership interest in our general partner and IDRs, and 111,000 Class B units of Plains AAP, L.P. Based on the market price of our common units at December 31, 2009 and an implied valuation for their collective general partner and IDR interests using similar valuation metrics, the value of the equity ownership of these individuals was significantly greater than the combined aggregate salaries and bonuses for 2009.

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

*Section 162(m).* With respect to the deduction limitations under Section 162(m) of the Code, we are a limited partnership and do not meet the definition of a corporation under Section 162(m).

*Change in Control Triggers.* The employment agreements for Messrs. Armstrong and Pefanis, the long-term incentive plan grants to our Named Executive Officers, and the Class B restricted units agreements include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreement. In the case of the long-term incentive plan grants, the provision becomes operative only if the change in control is accompanied by a change in status (such as the termination of employment by Plains All American GP LLC). We believe this double trigger arrangement is appropriate because it provides assurance to

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the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The provisions in the employment agreements for Messrs. Armstrong and Pefanis become operative only if the executive terminates employment within three months of the change in control. Messrs. Armstrong and Pefanis agreed to a conditional waiver of these provisions with respect to a sale transaction in August 2005 that would have constituted a change in control. The Class B restricted units agreements generally call for vesting upon a change in control of any units that have already been earned, plus the next increment of units that could be earned at the next distribution threshold. Any remaining Class B restricted units would be forfeited (unless waived at the discretion of the general partner or acquirer as the case may be). See Employment Contracts and Potential Payments upon Termination or Change-in-Control.

**Relation of Compensation Policies and Practices to Risk Management**

Our compensation policies and practices are designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business, requires some degree of risk-taking. Accordingly, the use of compensation as an incentive for performance can foster the potential for management and others to take unnecessary or excessive risks to reach the performance thresholds. For us, such risks would primarily attach to certain commercial activities conducted in our supply and logistics segment as well as to the execution of capital expansion projects and acquisitions and the realization of associated returns.

From a risk management perspective, our policy is to conduct our commercial activities within pre-defined risk parameters that are closely monitored and are structured in a manner intended to control and minimize the potential for unwarranted risk-taking. See Crude Oil Volatility; Counter-Cyclical Balance; Risk Management in Part I of this annual report. We also routinely monitor and measure the execution and performance of our capital projects and acquisitions relative to expectations.

Our compensation arrangements contain a number of design elements that serve to minimize the incentive for unwarranted risk-taking to achieve short-term, unsustainable results, including delaying the reward and subjecting such rewards to forfeiture for terminations related to violations of our risk management policies and practices or of our code of conduct. See Compensation Discussion and Analysis Relation of Compensation Elements to Compensation Objectives.

In combination with our risk-management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

**Summary Compensation Table**

The following table sets forth certain compensation information for our Chief Executive Officer, Chief Financial Officer, and the three other most highly compensated executive officers in 2009 (our Named Executive Officers). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation (excluding the costs of the obligations represented by the Class B units).

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Name and Principal Position	Year	Salary (\$)	Bonus (\$)	Stock Awards (\$)(1)	All Other Compensation (\$)(2)	Total (\$)
Greg L. Armstrong Chairman and CEO	2009	375,000	3,000,000		15,800	3,390,800
	2008	375,000	2,900,000		14,775	3,289,775
	2007	375,000	3,400,000	2,770,660	14,430	6,560,090
Harry N. Pefanis President and Chief Operating Officer	2009	300,000	2,900,000		15,800	3,215,800
	2008	300,000	2,800,000		14,775	3,114,775
	2007	300,000	3,200,000	1,958,805	14,430	5,473,235
Al Swanson Senior Vice President and Chief Financial Officer	2009	250,000	1,000,000	376,483	15,763	1,642,246
	2008	180,000	700,000		14,502	894,502
W. David Duckett(3) President PMC (Nova Scotia) Company	2009	251,058	3,378,240		83,643	3,712,941
	2008	268,095	2,915,424		88,831	3,272,350
	2007	266,960	3,028,488	1,177,531	93,501	4,566,480
John P. vonBerg Senior Vice President Commercial Activities	2009	250,000	3,220,000(4)		15,800	3,485,800
	2008	200,000	2,740,000(4)		14,580	2,954,580
	2007	200,000	2,765,000(4)	969,731	14,244	3,948,975



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(1) Dollar amounts represent the aggregate grant date fair value of phantom units and Class B units granted during each year based on the probable outcome of underlying performance conditions. For phantom units granted in 2007 and 2009, the performance threshold for the first tranche of vesting was deemed probable of occurrence as of the grant date. For Class B units granted in 2007, the performance threshold for the first tranche of earning was deemed probable of occurrence as of the grant date. The maximum grant date fair values of stock awards assuming that the highest level of performance conditions will be met are as follows:

Name	Year	Maximum Grant Date Fair Value (\$)
Greg L. Armstrong	2009	
	2008	
	2007	17,544,186
Harry N. Pefanis	2009	
	2008	
	2007	12,425,957
Al Swanson	2009	1,129,450
	2008	
W. David Duckett	2009	
	2008	
	2007	7,383,061
John P. VonBerg	2009	
	2008	
	2007	5,701,156

(2) Plains All American GP LLC matches 100% of employees' contributions to its 401(k) plan in cash, subject to certain limitations in the plan. All Other Compensation for each of Messrs. Armstrong, Pefanis, Swanson and vonBerg includes \$14,700 in such contributions for 2009. The remaining amount for each represents premium payments on behalf of such Named Executive Officer for group term life insurance. All Other Compensation for Mr. Duckett includes, for 2009, employer contributions to the PMC (Nova Scotia) Company savings plan of \$32,638, group term life insurance premiums of \$16,220, automobile lease payments of \$29,143 and club dues.

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

(4) Includes quarterly bonuses aggregating \$1,920,000, \$1,440,000 and \$1,765,000 and annual bonuses of \$1,300,000, \$1,300,000 and \$1,000,000 in 2009, 2008 and 2007, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Table of Contents**Grants of Plan-Based Awards Table**

The following table sets forth summary information regarding all grants of plan-based awards made to our Named Executive Officers during the fiscal year ended December 31, 2009.

Name	Grant Date	Estimated Future Payouts			Estimated Future Payouts			All Other Stock Awards: Number Of	All Other Option Awards: Number Of	Exercise or Base Price Of Option Awards	Grant Date Fair Value Of Stock and Option Awards
		Threshold (\$)	Target (\$)	Maximum (\$)	Threshold (\$)	Target (\$)	Maximum (\$)	Shares Of Stock or Units (#)	Securities Underlying Options (#)	(\$/Sh)	(\$)
Greg L. Armstrong											
Harry N. Pefanis											
Al Swanson	2/19/09							35,000(1)			\$ 376,483(2)
W. David Duckett											
John D. vonBerg											

(1) These phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least \$0.9375; one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least \$1.00; and one-third will vest upon the later of the May 2013 distribution date and the date on which we pay a quarterly distribution of at least \$1.0625. DERs associated with these units become payable in one-third increments upon achieving quarterly distribution levels of \$0.9125, \$0.9375 and \$1.00 per unit, respectively. Any phantom units that have not vested (and all associated DERs) as of the May 2015 distribution date will expire.

(2) Represents the grant date fair value of phantom units based on the probable outcome of underlying performance conditions. The performance threshold for the first one-third vesting was deemed probable of occurrence as of the grant date. The maximum grant date fair value of these phantom units assuming that the highest level of performance conditions will be met is \$1,129,450.

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

A discussion of 2009 salaries and bonuses is included in Compensation Discussion and Analysis. The following is a discussion of other material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and under Grants of Plan-Based Awards Table above.

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

*Grants of Plan-Based Awards* In February 2009, Mr. Swanson was awarded 35,000 phantom units under our LTIP. In February 2010, our Named Executive Officers were awarded the following phantom units: Mr. Armstrong, 180,000; Mr. Pefanis, 120,000; Mr. Swanson, 60,000; Mr. Duckett, 75,000; and Mr. vonBerg, 54,000.

### **Employment Contracts**

Mr. Armstrong is employed as Chairman and Chief Executive Officer. The initial three-year term of Mr. Armstrong's employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Armstrong receives notice from the chairman of the compensation committee that the board of directors has elected not to extend the agreement. Mr. Armstrong has agreed, during the term of the agreement and for five years thereafter, not to disclose (subject to typical exceptions, including, but not limited to, requirement of law or prior disclosure by a third party) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of \$330,000 per year, subject to annual review. In 2005, Mr. Armstrong's annual salary was increased to \$375,000.

Mr. Pefanis is employed as President and Chief Operating Officer. The initial three-year term of Mr. Pefanis' employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Pefanis receives notice from the Chairman

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of the Board that the board of directors has elected not to extend the agreement. Mr. Pefanis has agreed, during the term of the agreement and for one year thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of \$235,000 per year, subject to annual review. In 2005, Mr. Pefanis' annual salary was increased to \$300,000.

See Compensation Discussion and Analysis for a discussion of how we use salary and bonus to achieve compensation objectives. See Potential Payments upon Termination or Change-In-Control for a discussion of the provisions in Messrs. Armstrong's and Pefanis' employment agreements related to termination, change of control and related payment obligations.

**Outstanding Equity Awards at Fiscal Year-End**

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2009 with respect to our Named Executive Officers:

Name	Option Awards					Unit Awards			
	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unearned Options (#)	Option Exercise Price (\$)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested (\$)(1)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested (\$)(1)
Greg L. Armstrong						120,000(2)	\$ 6,342,000		
						60,000(3)	\$ 3,171,000	120,000(3)	\$ 6,342,000
						10,000(4)	\$ 2,770,700	30,000(4)	\$ 5,987,300
Harry N. Pefanis						80,000(2)	\$ 4,228,000		
						40,000(3)	\$ 2,114,000	80,000(3)	\$ 4,228,000
						7,500(4)	\$ 2,078,025	22,500(4)	\$ 4,490,475
Al Swanson						17,000(2)	\$ 898,450		
						11,000(3)	\$ 581,350	22,000(3)	\$ 1,162,700
						2,500(4)	\$ 692,675	35,000(5)	\$ 1,849,750
W. David Duckett						39,175(2)	\$ 2,070,399		
						25,000(3)	\$ 1,321,250	50,000(3)	\$ 2,642,500
						4,250	\$ 1,177,548	12,750(4)	\$ 2,544,602
John P. vonBerg						28,675(2)	\$ 1,515,474		
						18,000(3)	\$ 951,300	36,000(3)	\$ 1,902,600
						3,500(4)	\$ 969,745	10,500(4)	\$ 2,095,555

(1) Market value of phantom units reported in these columns is calculated by multiplying the closing market price (\$52.85) of our common units at December 31, 2009 (the last trading day of the fiscal year) by the number of units. No discount is applied for remaining performance threshold or service period requirements. The Class B units are valued based on the grant date fair value computed in accordance with FASB ASC Topic 718 assuming that the highest level of performance conditions will be met.

(2) All applicable performance (distribution) thresholds have been met, and these phantom units will vest upon the May 2010 distribution date. DERs associated with these phantom units have vested.

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(3) These phantom units will vest in one-third increments as follows: one-third will vest upon the May 2011 distribution date; one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least \$1.00; and one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least \$0.9375. The first 50% of DERs associated with these units is currently payable. The remaining 50% become payable in 25% increments upon achieving quarterly distribution levels of \$0.95 and \$1.00 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2014 distribution date will expire.

(4) Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P.'s asset values, but does not represent an interest in the capital of Plains AAP, L.P. on the applicable grant date of the Class B units. As of December 31, 2009, 25% of the Class B units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned. None of the Class B units have vested. For additional information regarding the Class B units, please read Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner Class B Units of Plains AAP, L.P.

(5) These phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least \$0.9375, one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least \$1.00, and one-third will vest upon the later of the May 2013 distribution date and the date on which we pay a quarterly distribution of at least \$1.0625. One-third of the DERs associated with these units is currently payable. The remaining two-thirds become payable in 50% increments upon achieving quarterly distribution levels of \$0.9375 and \$1.00 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2015 distribution date will expire.

**Option Exercises and Units Vested**

Name	Option Awards		Unit Awards	
	Number of Units Acquired on Exercise (#)(1)	Value Realized on Exercise (\$)	Number of Units Acquired on Vesting (#)(4)	Value Realized on Vesting (\$)(4)
Greg L. Armstrong	37,500	1,844,175(2)	90,000	3,710,700
Harry N. Pefanis	27,500	1,341,120(3)	60,000	2,473,800
Al Swanson			17,000	700,910
W. David Duckett			39,175	1,615,185
John P. vonBerg			28,675	1,182,270

(1) Represents the gross number and value of options exercised during the year ended December 31, 2009. The actual number of units delivered was net of the exercise price.

(2) The value realized upon exercise is based on the difference between the closing market price (\$52.41) of our common units on December 23, 2009 (the exercise date) and the exercise price of the options (\$3.232).

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(3) The value realized upon exercise is based on the difference between the closing market price (\$52.00) of our common units on December 22, 2009 (the exercise date) and the exercise price of the options (\$3.232).

(4) Represents the gross number and value of phantom units that vested during the year ended December 31, 2009. The actual number of units delivered was net of income tax withholding. Consistent with the terms of our 2005 Long-Term Incentive Plan, the value realized upon vesting is computed by multiplying the closing market price (\$41.23) of our common units on May 14, 2009 (the date preceding the vesting date) by the number of units that vested.

Table of Contents**Pension Benefits**

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

**Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans**

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

**Potential Payments upon Termination or Change-in-Control**

The following table sets forth potential amounts payable to the Named Executive Officers upon termination of employment under various circumstances, and as if terminated on December 31, 2009.

	By Reason of Death (\$)	By Reason of Disability (\$)	By Company without Cause (\$)	By Executive with Good Reason (\$)	In Connection with a Change In Control (\$)
<b>Greg L. Armstrong</b>					
Salary and Bonus	8,250,000(1)	8,250,000(1)	8,250,000(1)	8,250,000(1)	12,375,000(2)
Equity Compensation	12,684,000(3)	12,684,000(3)	15,855,000(4)	15,855,000(4)	15,855,000(5)
Health Benefits	N/A	32,102(6)	32,102(6)	32,102(6)	32,102(6)
Tax Gross-up	N/A	N/A	N/A	N/A	1,436,780(7)
Class B Units	N/A	N/A	N/A	N/A	5,382,400(8)
Total	20,934,000	20,966,102	24,137,102	24,137,102	35,081,282
<b>Harry N. Pefanis</b>					
Salary and Bonus	7,400,000(1)	7,400,000(1)	7,400,000(1)	7,400,000(1)	11,100,000(2)
Equity Compensation	8,456,000(3)	8,456,000(3)	10,570,000(4)	10,570,000(4)	10,570,000(5)
Health Benefits	N/A	38,632(6)	38,632(6)	38,632(6)	