PLAINS GP HOLDINGS LP
Form 10-K
March 12, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

or

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

Commission file number 1-36132

PLAINS GP HOLDINGS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**90-1005472**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Class A Shares, Representing Limited Partner Interests	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 o No x

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

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 x No o

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 x No o

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

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

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

As of June 30, 2013, the last day of the registrant s most recently completed second quarter, the registrant s Class A shares were not publicly traded. The aggregate market value of the Class A shares held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Class A shares outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $3.6 billion on December 31, 2013, based on a closing price of $26.77 per Class A share as reported on the New York Stock Exchange on such date.

As of March 6, 2014, there were 135,833,637 Class A shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

FORM 10-K 2013 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 st regarding our business strategy, plans and objectives for future operations. The absence of such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking 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 or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- our ability to pay distributions to our Class A shareholders;
- our expected receipt of, and amounts of, distributions from Plains AAP, L.P.;
- failure to implement or capitalize, or delays in implementing or capitalizing, on planned internal growth projects;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;
- tightened capital markets or other factors that increase our cost of capital or limit our access to capital;
- maintenance of PAA s credit rating and ability to receive open credit from suppliers and trade counterparties;

- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- the currency exchange rate of the Canadian dollar;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- 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 historical operations;
- the effectiveness of our risk management activities;
- declines in the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our facilities, whether due to declines in production from existing oil and gas reserves, failure to develop or slowdown in the development of additional oil and gas reserves or other factors;
- shortages or cost increases of supplies, materials or labor;
- 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 impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;
- non-utilization of our assets and facilities;
- the effects of competition;

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- increased costs or lack of availability of insurance;
- fluctuations in the debt and equity markets, including the price of PAA s units at the time of vesting under its long-term incentive plans;
- weather interference with business operations or project construction;
- risks related to the development and operation of our facilities, including our ability to satisfy our contractual obligations to our customers at our facilities;
- factors affecting demand for natural gas and natural gas storage services and rates;
- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

Other factors described herein, as well as 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 GP Holdings, L.P. (PAGP) is a Delaware limited partnership formed on July 17, 2013 to own an interest in the general partner and incentive distribution rights (IDRs) of Plains All American Pipeline, L.P (PAA), a publicly traded Delaware limited partnership. Although we were formed as a limited partnership, we have elected to be taxed as a corporation for United States federal income tax purposes. As used in this Form 10-K and unless the context indicates otherwise, the terms Partnership, Plains, PAGP, we, us, our, ours and similar terms refer to GP Holdings, L.P. and its subsidiaries.

Organizational History

We completed our initial public offering (IPO) in October 2013. Immediately prior to our IPO, certain owners of Plains AAP, L.P. (AAP) sold a portion of their interests in AAP to us, resulting in our ownership of a limited partnership interest in AAP. As of December 31, 2013, we owned a 22.1% limited partner interest in AAP, and the remaining limited partner interests in AAP continue to be held by the owners of AAP immediately prior to our IPO (the Legacy Owners). AAP is a Delaware limited partnership that directly owns all of PAA s incentive distribution rights and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP LLC (PAA GP), a Delaware limited liability company that directly holds the 2% general partner interest in PAA. Also, through a series of transactions prior to our IPO with our general partner and the owners of Plains All American GP LLC (GP LLC), a Delaware limited liability company formed on May 2, 2001, GP LLC s general partner interest in AAP became a non-economic interest, and we became the owner of a 100% managing member interest in GP LLC.

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PAA is a publicly traded master limited partnership that owns and operates midstream energy infrastructure and provides logistics services for crude oil, natural gas liquids (NGL), natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas (LPG) such as propane and butane. When used in this Form 10-K, NGL refers to all NGL products including LPG. PAA owns an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. On average, PAA handles over 3.5 million barrels per day of crude oil and NGL on its pipelines.

Partnership Structure and Management

Our general partner, PAA GP Holdings LLC, manages our operations and activities and is responsible for exercising on our behalf any rights we have as the managing member of GP LLC, including any rights to appoint members to the board of directors of GP LLC. See Item 10. Directors and Executive Officers of our General Partner and Corporate Governance. GP LLC has responsibility for managing the business and affairs of PAA and AAP; however, through our rights as the sole and managing member of GP LLC, we effectively control the business and affairs of AAP and PAA. GP LLC employs all domestic officers and personnel involved in the operation and management of PAA and AAP. PAA s Canadian officers and personnel are employed by Plains Midstream Canada ULC. Our general partner does not receive a management fee or other compensation in connection with its management of our business.

The two charts below show the structure and ownership of PAGP and certain subsidiaries as of December 31, 2013 in both an abridged and more detailed format. The first chart depicts PAGP s legal structure in summary format, while the second chart depicts a more comprehensive view of PAGP s legal structure, including ownership and economic interests and shares and units outstanding.

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Summarized Partnership Structure

(as of December 31, 2013)

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Detailed Partnership Structure

(as of December 31, 2013)

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(1) Incentive Distribution Rights (IDRs).

(2) PAA holds direct and indirect ownership interests in consolidated operating subsidiaries including, but not limited to, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Midstream Canada ULC (PMC).

(3) PAA holds indirect equity interests in unconsolidated entities including Settoon Towing, LLC (Settoon Towing), White Cliffs Pipeline, LLC (White Cliffs), Butte Pipe Line Company (Butte), Frontier Pipeline Company (Frontier) and Eagle Ford Pipeline LLC (Eagle Ford Pipeline).

(4) Represents the number of Class A units of AAP (AAP units) for which the Class B units of AAP (referred to herein as the AAP Management Units) would be exchangeable, assuming a conversion rate of approximately 0.90 AAP units for each AAP Management Unit as of December 31, 2013. The AAP Management Units are entitled to certain proportionate distributions paid by AAP.

(5) As of December 31, 2013, we owned 22.1% of the membership interests in our general partner, which percentage corresponds to our 22.1% ownership percentage of AAP units (representing a 20.6% economic interest in AAP, including the dilutive effect of the AAP Management Units).

Our Business

As of December 31, 2013, our only cash-generating assets consist of 133,833,637 AAP units, which represent a 22.1% limited partner interest in AAP (20.6% economic interest including the dilutive effect of the AAP Management Units). Unless we directly acquire and hold assets or businesses in the future, our cash flows will be generated solely from the cash distributions we receive from AAP. AAP does not own any common units in PAA and currently receives all of its cash flows from distributions on its direct ownership of PAA s IDRs and its indirect ownership of PAA s 2% general partner interest. AAP s ownership of both of these interests entitles it to receive, without duplication:

- 2% of all cash distributed in a quarter until $0.2250 has been distributed in respect of each common unit of PAA for that quarter;
- 15% of all cash distributed in a quarter after $0.2250 has been distributed in respect of each common unit of PAA for that quarter;
- 25% of all cash distributed in a quarter after $0.2475 has been distributed in respect of each common unit of PAA for that quarter; and

- 50% of all cash distributed in a quarter after $0.3375 has been distributed in respect of each common unit of PAA for that quarter.

Such amounts do not take into account temporary and permanent reductions in IDR payments that are currently in place in connection with past PAA acquisition activities or that may be implemented with respect to future activities. The cash distributions AAP receives from PAA are tied to (i) PAA s per unit distribution level and (ii) the number of PAA common units outstanding. An increase in either factor (assuming the other factor remains constant or increases) will generally, absent additional IDR reductions, result in an increase in the amount of cash distributions AAP receives from PAA, a portion of which we, in turn, receive from AAP. Because the IDRs currently participate at the maximum percentage participation rate, any future growth in distributions we receive from AAP will not result from an increase in the percentage participation rate associated with the IDRs.

Accordingly, our primary business objective is to increase our cash available for distribution to our Class A shareholders through the execution by PAA of its business strategy. In addition, we may facilitate PAA s growth activities through various means, including, but not limited to, modifying PAA s IDRs, making loans, purchasing equity interests or providing other forms of financial support to PAA.

PAA s Business Strategy

PAA s principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage, processing, fractionation and supply and logistics services to producers, refiners and other customers. Toward this end, PAA endeavors to address regional supply and demand imbalances for crude oil and NGL in the United States and Canada by combining the strategic location and capabilities of its transportation, terminalling, storage, processing and fractionation assets with its extensive supply, logistics and distribution expertise. To a lesser extent, PAA also engages in similar activities for natural gas and refined products. We believe PAA s successful execution of this strategy will enable it to generate sustainable earnings and cash flow. PAA intends to manage and grow its business by:

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- commercially optimizing its existing assets and realizing cost efficiencies through operational improvements;

- using its transportation (including pipeline, rail, barge and truck), terminalling, storage, processing and fractionation assets in conjunction with its supply and logistics activities to capitalize on inefficient energy markets and to address physical market imbalances, mitigate inherent risks and increase margin;

- developing and implementing internal growth projects that (i) address evolving crude oil and NGL needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities;

- selectively pursuing strategic and accretive acquisitions that complement its existing asset base and distribution capabilities; and

- capitalizing on anticipated intermediate to long-term opportunities for natural gas storage services in North America by owning and operating high-quality natural gas storage facilities and providing its current and future customers reliable, competitive and flexible natural gas storage and related services.

PAA s Competitive Strengths

We believe that the following competitive strengths position PAA to successfully execute its principal business strategy:

- *Many of PAA s transportation segment and facilities segment assets are strategically located and operationally flexible.* The majority of PAA s primary transportation segment assets are in crude oil service, are located in well-established oil producing regions and other transportation corridors and are connected, directly or indirectly, with PAA s facilities segment assets located at major trading locations and premium markets that serve as gateways to major North American refinery and distribution markets where PAA has strong business relationships. PAA s assets include pipeline, rail, barge and truck assets, which provide PAA s customers and PAA with significant flexibility and optionality to satisfy demand and balance markets, particularly during a dynamic period of changing product flows.

- *PAA possesses specialized crude oil market knowledge.* We believe PAA s business relationships with participants in various phases of the crude oil distribution chain, from crude oil producers to refiners, as well as PAA s own industry expertise, provide PAA with an extensive understanding of the North American physical crude oil markets.

- *PAA s supply and logistics activities typically generate a base level of margin with the opportunity to realize incremental margins.* We believe the variety of activities executed within PAA s supply and logistics segment in combination with PAA s risk management strategies provides PAA with a balance that generally affords it the flexibility to maintain a base level of margin in a variety of market conditions (subject to the effects of seasonality). In certain circumstances, PAA is able to realize incremental margins during volatile market conditions.

- *PAA has the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Over the past sixteen years, PAA has completed and integrated over 80 acquisitions with an aggregate purchase price of approximately $10.5 billion, which figures include over 30 acquisitions totaling approximately $5.2 billion in aggregate purchase price over the last six years. PAA has also implemented internal expansion capital projects totaling over $5.8 billion. In addition, we believe PAA has the resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2013, PAA had over $1.8 billion available under its committed credit facilities, subject to continued covenant compliance.

- *PAA has an experienced management team whose interests are aligned with those of its unitholders.* PAA s executive management team has an average of 29 years industry experience, and an average of 17 years with PAA or its predecessors and affiliates. In addition, through their ownership of common units, indirect interests in PAA s general partner, grants of phantom units and AAP Management Units, PAA s management team has a vested interest in PAA s continued success.

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Our Financial Strategy

Our financial strategy is designed to be complementary with PAA s financial and business strategies. Because our only cash-generating assets consist of our partnership interests in AAP, which currently derives all of its cash flows from PAA s distributions, we intend to maintain a level of indebtedness at AAP such that it will not be material in relation to PAA s adjusted EBITDA or other financial metrics used in the evaluation of its business. As of December 31, 2013, AAP had $515 million of debt outstanding under its credit facility. In connection with future PAA equity issuances, we expect AAP may fund any capital contribution required to maintain its indirect 2% general partner interest in PAA with credit facility borrowings. We do not anticipate that additional debt associated with these contributions will be material to PAA s consolidated credit profile, as such equity issuances are typically used to pay down existing debt or fund PAA s growth through acquisitions or organic growth opportunities. We would expect to fund direct acquisitions made by us, if any, with a combination of debt and equity.

PAA s Financial Strategy

Targeted Credit Profile

We believe that a major factor in PAA s continued success is its ability to maintain a competitive cost of capital and access to the capital markets. In that regard, PAA intends to maintain a credit profile that it believes is consistent with investment grade credit ratings. PAA has targeted a general credit profile with the following attributes:

- an average long-term debt-to-total capitalization ratio of approximately 45% to 50%;
- a long-term debt-to-adjusted EBITDA multiple averaging between 3.5x and 4.0x (Adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity-indexed compensation plan charges, gains and losses from derivative activities and other selected items that impact comparability);
- 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. PAA also incurs short-term debt in connection with its supply and logistics activities that involve the simultaneous purchase and forward sale of crude oil, NGL and natural gas. The crude oil, NGL and natural gas purchased in these transactions are hedged. PAA does not consider the working capital borrowings associated with these activities to be part of its long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds. PAA also incurs short-term debt to fund New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin requirements. In certain market conditions, these routine short-term debt levels may increase significantly above baseline levels.

In order for PAA to maintain its targeted credit profile and achieve growth through internal growth projects and acquisitions, PAA intends to fund approximately 55% of the capital requirements associated with these activities with equity and cash flow in excess of distributions. From time to time, PAA may be outside the parameters of its targeted credit profile as, in certain cases, these capital expenditures and acquisitions may be financed initially using debt or there may be delays in realizing anticipated synergies from acquisitions or contributions from capital expansion projects to adjusted EBITDA.

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PAA s Acquisitions

The acquisition of midstream assets and businesses that are strategic and complementary to PAA s existing operations constitutes an integral component of its business strategy and growth objectives. Such assets and businesses include crude oil, refined products and NGL logistics assets, natural gas storage assets and other energy assets that have characteristics and provide opportunities similar to such business lines and enable PAA to leverage its assets, knowledge and skill sets.

The following table summarizes acquisitions greater than $200 million that PAA has completed over the past five years (in millions). See Note 3 to our Consolidated Financial Statements for a full discussion regarding acquisition activities.

Acquisition (1)	**Date**	**Description**		**Approximate Purchase Price (2)**
US Development Group Crude Oil Rail Terminals (USD)	Dec-2012	Four operating crude oil rail terminals and one terminal under development	$	503
BP Canada Energy Company (BP NGL)	Apr-2012	NGL assets located in Canada and the upper-Midwest United States	$	1,683(3)
Western Refining, Inc. Pipeline and Storage Assets (Western)	Dec-2011	Multi-product storage facility in Virginia and a crude oil pipeline in southeastern New Mexico	$	220(4)
Velocity South Texas Gathering, LLC (Velocity)	Nov-2011	Crude oil and condensate gathering and transportation assets in South Texas (Gardendale Gathering System)	$	349
SG Resources Mississippi, LLC (SG Resources)	Feb-2011	Southern Pines Energy Center (Southern Pines) natural gas storage facility	$	765(5)
Nexen Holdings U.S.A. Inc. Gathering and Transportation Assets (Nexen)	Dec-2010	Crude oil gathering business and transportation assets in North Dakota and Montana	$	229(6)
PAA Natural Gas Storage, LLC (PNGS)	Sep-2009	Remaining 50% interest in PNGS	$	215(7)

(1) Excludes PAA s acquisition of all of the outstanding publicly-traded common units of PAA Natural Gas Storage, L.P. (PNG) on December 31, 2013 (referred to herein as the PNG Merger), as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with generally accepted accounting principles in the United States (GAAP). As consideration for the PNG Merger, PAA issued approximately 14.7 million of its common units with a value of approximately $760 million.

(2) As applicable, the approximate purchase price includes total cash paid and debt assumed, including amounts for working capital and inventory.

(3) Purchase price includes approximately $17 million of imputed interest. A prepayment of $50 million was made during 2011. Approximate purchase price of $1.192 billion, net of working capital, linefill and long-term inventory acquired.

(4) Includes two transactions with Western.

(5) Approximate purchase price of $750 million, net of cash and other working capital acquired.

(6) Approximate purchase price of $170 million, net of cash, inventory and other working capital acquired.

(7) In connection with the PNGS acquisition PAA consolidated and subsequently refinanced approximately $450 million of previously non-recourse joint venture debt.

Ongoing Acquisition Activities. Consistent with its business strategy, PAA is continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to PAA s existing operations. In addition, PAA has in the past evaluated and pursued, and intends in the future to evaluate and pursue, other energy-related assets that have characteristics and provide opportunities similar to PAA s existing business lines and enable PAA to leverage its assets, knowledge and skill sets. Such acquisition efforts may involve participation by PAA 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 PAA believes it is 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 PAA s financial condition and results of operations.

PAA typically does not announce a transaction until after it has executed a definitive acquisition agreement. However, in certain cases in order to protect its business interests or for other reasons, PAA may defer public announcement of an acquisition until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential acquisition can advance or terminate in a short period of time. Moreover, the closing of any transaction for which PAA has entered into a definitive acquisition agreement will be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, PAA can give no assurance that its current or future acquisition efforts will be successful. Although PAA expects the acquisitions it makes to be accretive in the long term, PAA can provide no assurance that its expectations will ultimately be realized. See Item 1A. Risk Factors Risks Related to PAA s Business If PAA does not make acquisitions or if it makes acquisitions that fail to perform as anticipated, its future growth may be limited and PAA s acquisition strategy involves risks that may adversely affect its business.

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PAA s Organic Growth Projects

PAA s extensive asset base and its relationships with customers provide it with opportunities for organic growth through the construction of additional assets that are complementary to, and expand or extend, its existing asset base. PAA believes that the diversity and balance of its organic project portfolio (i.e., relatively large number of projects that are small to medium sized and spread across multiple geographic regions) reduces its overall exposure to cost overruns, timing delays and other adverse market developments with respect to a particular project or region. PAA s 2014 capital plan is representative of the diversity and balance of its overall organic project portfolio. The following expansion projects are included in PAA s 2014 capital plan as of February 2014:

Basin/Region	Project	2014 Plan Amount (1) ($ in millions)		Description
Permian	Permian Basin Area Projects	$	430	Multiple projects to increase and expand pipeline infrastructure in the Permian Basin, including the construction of three new trunklines and related assets
	Cactus Pipeline		310	310 miles of new pipeline; 250,000 Bbls/d capacity pipeline from the Permian Basin to the Eagle Ford JV Pipeline
Eagle Ford	PAA/Enterprise Products Partners Eagle Ford Joint Venture Project		60	Expansion of Eagle Ford JV pipeline capacity to 470,000 barrels per day; construction of additional 2.3 million barrels of storage capacity
	Gardendale Fractionator and Stabilizer		35	New NGL fractionator, expansion of existing condensate stabilization facility and related infrastructure enhancements in the Eagle Ford area of South Texas
Mid-Continent	Western Oklahoma Extension		50	95 miles of new pipeline; 75,000 Bbls/d of capacity from Reydon, OK to Orion Station in Major County, OK
	Mississippian Lime Pipeline		45	45 miles of new crude oil pipeline to complement our existing Mississippian Lime pipelines
Rockies/Williston	White Cliffs Pipeline Expansion		40	35.7% interest in 80,000 Bbls/d expansion of capacity through the construction of a new 12-inch diameter pipeline looping the existing pipeline
West Coast	Line 63 Reactivation		35	Reactivation of 71 miles of idled pipeline and supporting assets
Canada	Fort Saskatchewan Facility Projects / NGL pipeline		180	Development of two new NGL storage caverns and conversion of service of two existing caverns
Various	Rail Terminal Projects		185	Includes new rail facilities and expansion projects located at or near Bakersfield, CA; Carr, Co; Van Hook, ND; and Western Canada
	Natural Gas Storage		25	Multiple projects
	Other Projects		305	
		$	1,700	

(1) Represents the portion of the total project cost expected to be incurred during the year.

Global Petroleum Market Overview

The United States comprises less than 5% of the world s population, generates approximately 14% of the world s petroleum production, and consumes approximately 21% of the world s petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil and NGL) and is derived from the Energy Information Administration s (EIA) Annual Energy Outlook 2014 Early Release (see EIA website at *www.eia.doe.gov*):

		Projected (2)			
	2013 (1) (2)	2014	2015	2016	2020
	(In millions of barrels per day)				
Supply					
OECD **(3)**					
U.S.	12.3	13.1	13.7	14.2	14.2
Other	11.5	11.8	12.1	11.6	11.2
Total OECD	23.8	24.9	25.7	25.8	25.4
Organization of the Petroleum Exporting Countries	35.8	35.7	36.0	36.7	39.6
Other	30.4	30.7	30.7	31.4	33.0
Total World Production **(4)**	89.9	91.3	92.5	93.8	98.0

		Projected (2)			
	2013 (1) (2)	2014	2015	2016	2020
	(In millions of barrels per day)				
Demand					
OECD					
U.S.	18.8	18.8	19.2	19.4	19.5
Other	27.2	26.9	26.8	26.9	27.3
Total OECD	46.1	45.6	46.1	46.3	46.8
Other	44.3	45.6	46.4	47.5	51.2
Total World Consumption **(4)**	90.4	91.3	92.5	93.8	98.0

U.S. Production as % of World Production	14%	14%	15%	15%	14%
[redacted]					
Net U.S. (Consumption)	(6.5)	(5.7)	(5.5)	(5.2)	(5.3)

(1) The 2013 amounts are derived from the EIA s Short-Term Energy Outlook.

(2) Amounts may not recalculate due to rounding.

(3) Organization for Economic Co-operation and Development.

(4) Production and consumption may not equal in every year due to inventory builds or draws.

World economic growth is a driver of the world petroleum market. The challenging global economic climate of the last several years has resulted in continued uncertainty in the petroleum market. To the extent that an event causes weaker world economic growth, energy demand would likely decline and could 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 oil grade has distinguishing physical properties. For example, specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content, along with other characteristics, 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. The nature and extent of these imbalances change from time to time as a result of a variety of factors, including regional production declines and/or increases; refinery expansions, modifications and shut-downs; available transportation and storage capacity; and government mandates and related regulatory factors.

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Over the last five years, one of the most significant developments impacting the crude oil market has been the rapid growth in North American crude oil production. As a result of advances in horizontal drilling and fracturing technology over the last several years and their application to various large scale resource plays, certain historical trends have been reversed as domestic crude oil supplies have increased substantially and are expected to continue to increase over the next five years and potentially beyond. This production is being developed both in mature producing areas such as the Rockies, the Permian Basin in West Texas and the Mid-Continent region, as well as in less mature, but rapidly growing areas such as the Eagle Ford Shale in South Texas and the Bakken Shale in North Dakota. We forecast that by December 2017, crude oil production in the United States and Canada will have increased by an average of approximately 2.9 million barrels per day from fourth-quarter 2013 levels, with the increases coming primarily from Canada, the Eagle Ford Shale in South Texas, the Permian Basin in West Texas and the Bakken Shale in North Dakota. Actual and anticipated production increases in all of these regions combined with actual and anticipated volumes from Canada have strained or are expected to strain existing transportation, terminalling and downstream infrastructure. These changes have resulted in significant alterations to historical patterns of crude oil movements among regions of the U.S. For example, the quantity of crude oil transported from the Gulf Coast area into the Midwest has declined, but the overall change in crude oil flows has resulted in an increased demand for storage and terminalling services at Cushing, Oklahoma and Patoka, Illinois.

In addition to overall production growth, significant shifts in the type and location of crude oil being produced from these regions have resulted in additional strains on existing infrastructure. Notably, the increase in domestic production of light, sweet crude oil is inconsistent with the sizeable, multi-year investments made by a number of U.S. refining companies in order to expand their capabilities to process heavier, sour grades of crude oil. This divergence between readily available supplies of light sweet crude oil and increased refinery demand for heavy sour crude oil has begun to cause differentials between crude oil grades and qualities to change relative to historical levels and become more dynamic and volatile. This increase in light sweet crude oil production has also resulted in a decrease in foreign imports of light sweet crude into the U.S., particularly into the Gulf Coast, which has caused the international producers of such lighter crudes to seek alternative markets in other parts of the world. Thus far it appears that the rest of the world has been able to absorb the previously imported barrels, but that could change over time as worldwide demand fluctuates.

Since reaching a multi-year low in 2009, U.S. net refinery inputs of crude oil have slowly increased to a level of 15.2 million barrels per day for the twelve month period ending November 2013, which approximates the levels achieved during 2005 and 2006. Although domestic demand for petroleum products from end users has declined from peak levels in 2004 2007 and the increased use of ethanol for blending in gasoline has further negatively impacted refinery demand for crude oil, the attractive export market for refined products and access to discounted domestic crude oil has driven the increased refinery demand. Domestic production growth has also led to lower use of imported crude oil by U.S. refineries, a meaningful change in a multi-year trend where foreign imports of crude oil tripled over an approximately 23-year period from 1985 2007. The EIA is currently forecasting a continued gradual decline in foreign crude imports from current levels, which is attributable to increased domestic production and increased supply from other liquid products, including ethanol and biodiesel.

The table below shows the overall domestic petroleum consumption projected out to 2020 and is derived from recent information published by the EIA (see EIA website at *www.eia.doe.gov*). The amounts in the 2013 column are based on the 12 months ended November 2013**.** We believe these trends will be subject to significant variation from time to time due to a number of factors, including the level of domestic production volumes and infrastructure limitations which impact pricing and geopolitical developments.

	Actual (1)	**Projected (1)**			
	2013	**2014**	**2015**	**2016**	**2020**
			(In millions of barrels per day)		
Supply					
Domestic Crude Oil Production	7.4	8.5	9.0	9.5	9.6
Net Imports - Crude Oil from Canada	2.4	3.1	3.3	3.2	3.1
Net Imports - Crude Oil from Other	5.2	3.4	2.9	2.5	2.7
Other (Supply Adjustment / Stock Change)	0.2				
Crude Oil Input to Domestic Refineries	15.2	15.0	15.2	15.3	15.3

Product Imports	1.9	1.9	2.0	2.1	2.1
Product Exports	(2.9)	(2.9)	(3.0)	(3.0)	(3.0)
Net Product Imports / (Exports)	(1.0)	(1.0)	(1.0)	(0.9)	(0.9)
Supply from Renewable Sources	1.0	0.9	1.0	1.0	1.0
Other - (NGL Production, Refinery Processing Gain)	3.6	3.9	4.0	4.0	4.0
Total Domestic Petroleum Consumption	18.8	18.8	19.2	19.4	19.5

(1) Amounts may not recalculate due to rounding.

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As illustrated in the table above, while expected to decline, imports of foreign crude oil and other petroleum products are still expected to play a major role in achieving a balanced U.S. market on an aggregate basis. However, because of the substantial number of different grades and varieties of crude oil and their distinguishing physical and economic properties and the distinct configuration of each refinery s process units, significant logistics infrastructure and services are required to balance the U.S. market on a region by region basis.

By way of illustration, 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 November 2013 and is derived from information published by the EIA (see EIA website at *www.eia.doe.gov*):

Petroleum Administration Defense District (in millions of barrels per day) (1)	**Regional Supply**	**Refinery Demand**	**Supply Shortfall**
PADD I (East Coast)		1.0	(1.0)
PADD II (Midwest)	1.4	3.4	(2.0)
PADD III (South)	4.3	7.9	(3.6)
PADD IV (Rockies)	0.5	0.6	(0.1)
PADD V (West Coast)	1.1	2.3	(1.2)
Total U.S.	7.4	15.2	(7.9)

(1) Amounts may not recalculate or cross-foot due to rounding.

Overall, volatility of multiple aspects of the crude oil market, including absolute price, market structure and grade and location differentials, has increased over time and we expect volatility to continue. Some factors that we believe are causing and will continue to cause volatility in the market include:

- the multi-year growth in North American crude oil production;
- fluctuations in international supply and demand related to the economic environment, geopolitical events and armed conflicts;
- regional supply and demand imbalances and changes in refinery capacity and specific capabilities;
- significant fluctuations in absolute price as well as grade and location differentials;
- political instability in critical producing nations; and

- policy decisions made by various governments around the world attempting to navigate energy challenges.

The complexity and volatility of the crude oil market creates opportunities to solve the logistical inefficiencies inherent in the business. The combination of (i) a significant increase in North American production volumes, (ii) a change in crude oil qualities and related differentials and (iii) a high utilization of existing pipeline and terminal infrastructure has stimulated multiple industry initiatives to build new pipeline and terminal infrastructure, convert certain pipeline assets to alternative service or reverse flows and expand the use of trucks, rail and barges for the movement of crude oil and condensate.

Refined Products Market Overview

After transport to a refinery, the crude oil 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 and diesel.

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.

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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, conservation, fuel efficiency mandates and, to a lesser extent, weather conditions. From 2008 through the 12 months ended November 2013, petroleum consumption averaged approximately 18.8 million barrels per day, an approximate 10% decrease from peak levels, largely due to economic weakness and increased and expanding fuel efficiency standards. Given this decreased demand for refined products, the increased use of ethanol and other renewable fuels and the resulting excess refining capacity, a number of U.S. refineries reduced output and, in some cases, indefinitely shut-down. The EIA is currently forecasting growth in overall refined product demand to increase marginally over the next decade.

The level of future domestic demand generally will be influenced by economic conditions as well as the absolute prices of the products. Counteracting the impact of decreased domestic refined product demand on many U.S. refineries has been the combination of a significant decrease in refined product imports and a significant increase in refined product exports. Refined product imports decreased from 3.2 million barrels per day in 2005 to an average of approximately 1.9 million barrels per day for the 12 months ended November 2013. Conversely, refined product exports increased from approximately 1.1 million barrels per day in 2005 to 2.9 million barrels per day for the 12 months ended November 2013. We believe that potential demand growth will be met primarily by the increase in mandated alternative fuels and increased utilization of existing refining capacity, which could generate demand for midstream infrastructure in certain areas, including pipelines and terminals.

NGL Market Overview

NGL primarily includes ethane, propane, normal butane, iso-butane, and natural gasoline, and is derived from natural gas production and processing activities as well as crude oil refining processes. LPG primarily includes propane, butane, and natural gasoline, which liquefy at moderate pressures thus making it easier to transport and store such products as compared to ethane. As discussed above, NGL refers to all NGL products including LPG when used in this document.

NGL Demand. Individual NGL products have varying uses. Described below are the five basic NGL components and their typical uses:

- *Ethane.* Ethane accounts for the largest portion of the NGL barrel and substantially all of the extracted ethane is used as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. When ethane recovery from a wet natural gas stream is uneconomic, ethane is left in the natural gas stream, subject to pipeline specifications.

- *Propane.* Propane is used as heating fuel, engine fuel and industrial fuel, for agricultural burning and drying and also as petrochemical feedstock for the production of ethylene and propylene.

- *Normal butane.* Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with propane, and feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used as a feedstock for iso-butane production and as a diluent in the transportation of heavy crude oil and bitumen, particularly in Canada.

- *Iso-butane.* Iso-butane is principally used by refiners to produce alkylates to enhance the octane content of motor gasoline.

- *Natural Gasoline.* Natural gasoline is principally used as a motor gasoline blend stock, a petrochemical feedstock, or as diluent in the transportation of heavy crude oil and bitumen, particularly in Canada.

NGL Supply. The bulk (approximately 75%) of the United States NGL supply comes from gas processing plants, which separate a mixture of NGL from the dry gas (primarily methane). The NGL mix (also referred to as Y Grade) is then either fractionated at the processing site into the five individual NGL components (known as purity products), which may be transported, stored and sold to end use markets or transported as a Y-Grade to a regional fractionation facility.

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The majority of gas processing plants in the United States are located along the Gulf Coast, in the West Texas/Oklahoma area and in the Rockies region. Smaller gas processing regions are located in Michigan and Illinois as well as the Marcellus region (which is expanding rapidly) and Southern California. In Canada, the vast majority of the processing capacity is located in Alberta, with a much smaller (but increasing) amount in British Columbia and Saskatchewan.

NGL products from refineries represent approximately 19% of the United States supply and are by-products of the refinery conversion processes. Consequently, they have generally already been separated into individual components and do not require further fractionation. NGL products from refineries are principally propane, with lesser amounts of butane, refinery naphthas (products similar to natural gasoline) and ethane. Due to refinery maintenance schedules and seasonal demand considerations, refinery production of propane and butane varies on a seasonal basis.

NGL is also imported into certain regions of the United States from Canada and other parts of the world (approximately 6% of total supply). NGL (primarily propane) is also exported from certain regions of the United States.

NGL Transportation and Trading Hubs. NGL, whether as a mixture or as purity products, is transported by pipelines, barges, railcars and tank trucks. The method of transportation used depends on, among other things, the resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of product being transported. Pipelines are generally the most cost-efficient mode of transportation when large, consistent volumes of product are to be delivered.

The major NGL infrastructure and trading hubs in North America are located at Mont Belvieu, Texas; Conway, Kansas; Edmonton, Alberta; and Sarnia, Ontario. Each of these hubs contains a critical mass of infrastructure, including fractionators, storage, pipelines and access to end markets, particularly Mont Belvieu. In addition, there are several other production hubs, including Empress, Alberta and Hobbs, New Mexico. The West Virginia/Western Pennsylvania area is also rapidly developing as a meaningful NGL infrastructure hub.

NGL Storage. NGL must be stored under pressure to maintain a liquid state. The lighter the product (e.g., ethane), the greater the pressure that must be maintained. Large volumes of NGL are stored in underground caverns constructed in salt or granite. Product is also stored in above ground tanks. Natural gasoline can be stored at relatively low pressures in tankage similar to that used to store motor gasoline. Propane and butane are stored at much higher pressures in steel spheres, cylinders, bullets, salt caverns or other configurations. Ethane is stored at very high pressures, typically in salt caverns. Storage is especially important for NGL as supply and demand can vary materially on a seasonal basis.

NGL Market Outlook. NGL supplies from gas processing plants are increasing rapidly due to the increased drilling activity in unconventional resource plays. Numerous industry and financial analysts project NGL supply volumes will continue to grow over the next several years with some analysts projecting U.S. supply volumes to increase from 2013 levels over 30% by 2017. A significant amount of this volume is expected to come from recently discovered, unconventional resource plays that do not have the NGL infrastructure to process the wet natural gas or transport, fractionate, and store the NGL products. Nor are these new supply areas near historical markets for the NGL purity products. As a result of these dynamics, substantial incremental infrastructure is likely to be developed throughout the NGL value chain over the next several years, and traditional regional basis relationships could change significantly. The expected continuation of a relatively low ratio of North American gas and NGL prices to world-wide crude oil prices means North American NGL will continue to be competitive on a world scale, either as feedstock for North American based manufacturing or export to overseas markets. Thus, a portion of the increased supply of NGL will be absorbed by the domestic petrochemical sector as low-cost feed stocks, as the North American petrochemical industry has a supply cost advantage on a world scale. In addition, growing production of Canadian heavy crude oil is likely to create demand for additional diluents, primarily natural gasoline and butane. The remaining product not absorbed domestically will likely drive continued growth in the NGL export market. Due to rapid increases in NGL production, the prices of NGL (particularly ethane and propane) have been pressured relatively downward in certain regions. It is difficult to predict when such prices may rebound but this downward pressure on prices is one of the key drivers for the new infrastructure development referred to above. The NGL market is, among other things, expected to be driven by:

- the absolute prices of NGL products and their prices relative to natural gas and crude oil;
- drilling activity and wet natural gas production in developing liquids-rich production areas;
- production growth/decline rates of wet natural gas in established supply areas;
- available processing, fractionation, storage and transportation capacity;

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- infrastructure development costs and timing as well as development risk sharing;
- the cost of acquiring rights from producers to process their gas;
- petro-chemical demand;
- diluent requirements for heavy Canadian oil;
- international demand for NGL products;
- regulatory changes in gasoline specifications affecting demand for butane;
- refinery shut downs;
- alternating needs of refineries to store and blend NGL;
- seasonal shifts in weather; and
- inefficiencies caused by regional supply and demand imbalances.

As a result of these and other factors, the NGL market is complex and volatile, which along with expected market growth creates opportunities to solve the logistical inefficiencies inherent in the business.

Natural Gas Storage Market Overview

North American natural gas storage facilities provide a staging and warehousing function for seasonal swings in demand relative to supply, as well as an essential reliability cushion against disruptions in natural gas supply, demand and transportation by allowing natural gas to be injected into, withdrawn from or warehoused in such storage facilities as dictated by market conditions. Natural gas storage serves as the shock absorber that balances the market, serving as a source of supply to meet the consumption demands in excess of daily production capacity and a warehouse for gas production in excess of daily demand during low demand periods.

Overall market conditions for natural gas storage have been challenging during the last several years, driven by a variety of factors, including (i) increased natural gas supplies due to production from shale resources, (ii) increased availability of storage capacity due to both new construction and the release of previously contracted storage capacity into the market as customers reduce their storage positions and/or exit the market, (iii) a reduction in overall market depth due to various companies exiting the physical gas marketing business, and (iv) lower basis differentials due to expansion and improved connectivity of natural gas transportation infrastructure over the last five years. Due to these factors, both seasonal spreads, which are a proxy for the current intrinsic value of natural gas storage, and volatility levels, which impact the value we are able to realize on a short-term basis from our hub service and merchant storage activities, have been low relative to values experienced during the last seven years.

Longer term, we believe several factors will contribute to meaningful growth in North American natural gas demand that will bolster the market need for and the commercial value of natural gas storage. These fundamental factors include (i) exports of North American volumes of LNG, (ii) construction of new gas-fired power plants, (iii) sustained fuel switching from coal to natural gas among existing power plants and (iv) growth in base-level industrial demand. As a result, we remain optimistic about the intermediate- to long-term intrinsic value of our natural gas storage assets.

However, projected seasonal spreads for the next few years reflect a directionally similar picture to the challenging market conditions we experienced during most of 2013. While recent extremely cold weather has added volatility and uncertainty to the market in the short term, it is difficult to predict the extent to which such conditions will impact overall market conditions on a longer term basis. A return to and continuation of the market conditions that prevailed during most of 2013 will continue to adversely impact our hub services activities as well as the lease rates our customers are willing to pay for firm storage services with respect to new capacity under construction and existing capacity upon expirations of existing term leases.

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Description of Segments and Associated Assets

Under GAAP, we consolidate AAP and PAA and its subsidiaries. We currently have no separate operating activities apart from those conducted by PAA. As such, our segment analysis, presentation and discussion is the same as that of PAA, which conducts its operations through three segments Transportation, Facilities and Supply and Logistics. Accordingly, any references to we, our, and similar terms describing assets, business characteristics or other related matters are references to assets, business characteristics or other matters involving PAA s assets and operations.

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 NGL on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and other transportation fees. Our transportation segment also includes our equity earnings from our investments in Settoon Towing and the White Cliffs, Butte, Frontier and Eagle Ford pipeline systems, in which we own interests ranging from 22% to 50% and account for under the equity method of accounting.

As of December 31, 2013, we employed a variety of owned or, to a much lesser extent, leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 16,900 miles of active crude oil and NGL pipelines and gathering systems;
- 24 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 744 trailers (primarily in Canada); and
- 130 transport and storage barges and 62 transport tugs through our interest in Settoon Towing.

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The following is a tabular presentation of our active crude oil and NGL pipeline assets in the United States and Canada as of December 31, 2013, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	**System Miles**	**2013 Average Net Barrels per Day (2) (in thousands)**
United States Crude Oil Pipelines		
Permian Basin		
Basin / Mesa	599	718
Permian Basin Area Systems	2,944	581
Permian Basin Subtotal	3,543	1,299
South Texas/Eagle Ford		
Eagle Ford Area Systems	439	102
Western		
All American	138	40
Line 63 / Line 2000	354	113
Other	129	94
Western Subtotal	621	247
Rocky Mountain		
Bakken Area Systems	953	131
Salt Lake City Area Systems	983	131
White Cliffs (3)	527	23
Other	1,316	113
Rocky Mountain Subtotal	3,779	398
Gulf Coast		
Capline (3)	631	151
Other	898	291
Gulf Coast Subtotal	1,529	442
Central		
Mid-Continent Area Systems	2,298	281
Other	313	124
Central Subtotal	2,611	405
United States Total	**12,522**	**2,893**
Canada		
Crude Oil Pipelines:		
Manito	555	46
Rainbow	858	124
Rangeland	1,316	60
South Saskatchewan	341	51
Other	99	102
Crude Oil Pipelines Subtotal	3,169	383
NGL Pipelines:		
Co-Ed	772	56
Other	435	194
NGL Pipelines Subtotal	1,207	250

Canada Total	**4,376**	**633**
Grand Total	**16,898**	**3,526**

(1) Ownership percentage varies on each pipeline and gathering system ranging from approximately 20% to 100%. In 2013, we sold certain of our refined products pipeline systems and related assets.

(2) Represents average volume for the entire year attributable to our interest.

(3) Pipelines operated by a third party.

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United States Pipelines

Permian Basin

Basin Pipeline System. We own an 87% undivided joint interest in and are the 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 also serves as the initial movement for transporting crude oil from the Permian Basin to the Gulf coast through connections to other carriers at Colorado City, Texas and Wichita Falls, Texas. The Basin system accommodates three primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink/Hendrick and Midland; (ii) barrels that are shipped from Midland to connecting carriers at Colorado City or Wichita Falls; and (iii) barrels that are shipped from Jal, Midland, Colorado City and Wichita Falls to connecting carriers at Cushing.

The Basin system is an approximate 520-mile mainline, telescoping crude oil system with a system capacity ranging from approximately 144,000 barrels per day to 450,000 barrels per day (approximately 125,000 barrels per day to 392,000 barrels per day attributable to our interest) depending on the segment. System throughput (as measured by tariff volumes) was approximately 512,000 barrels per day (attributable to our interest) during 2013. The Basin system is subject to tariff rates regulated by the Federal Energy Regulatory Commission (FERC).The system also includes approximately 6 million barrels of tankage. In 2013, we announced a project to increase capacity on the segment from Jal to Wink/Hendrick from 144,000 barrels per day to 240,000 barrels per day (approximately 125,000 barrels per day to 208,800 barrels per day attributable to our interest), which will be completed in 2014.

Mesa Pipeline System. We own a 63% interest in and are the operator of the Mesa Pipeline system, which transports crude oil from Midland to a refinery at Big Spring, Texas and to connecting carriers at Colorado City. The Mesa system is an 80-mile mainline with a system capacity of up to 360,000 barrels per day (approximately 226,800 barrels per day attributable to our interest). System throughput (as measured by tariff volumes) was approximately 206,000 barrels per day (attributable to our interest) during 2013.

Permian Basin Area Systems. We operate wholly owned systems of approximately 2,950 miles that aggregate receipts from wellhead gathering lines and bulk truck injection locations into a combination of 4- to 16-inch diameter trunk lines for transportation and delivery into the Basin system at Jal, Wink and Midland as well as our terminal facilities in Midland. These systems are subject to tariff rates regulated by either the FERC or state regulatory agencies. During 2012 and 2013, we completed construction of multiple expansion and extension projects servicing the Bone Spring, Spraberry and Wolfberry producing areas in the Permian Basin. For 2013, combined throughput on the Permian Basin area systems totaled an average of approximately 581,000 barrels per day.

In 2013, we announced several new projects to increase and expand our Permian Basin infrastructure over the next few years to support crude oil production growth. These projects are expected to be completed in stages throughout 2014 and early 2015 and include:

- a new 310-mile crude oil pipeline extending from McCamey to Gardendale, Texas to provide 200,000 barrels per day (which, based on shipper demand, may be increased to 250,000 barrels per day) of additional takeaway capacity from the Permian Basin (the Cactus Pipeline);

- a new 40-mile crude oil pipeline with 100,000 barrels per day of pipeline capacity from Monahans to Crane, Texas to supply volumes to a third-party pipeline as well as the Cactus Pipeline;

- a new 62-mile crude oil pipeline with 200,000 barrels of takeaway capacity from the South Midland Basin to the origin of the Cactus Pipeline at McCamey; and

- a new 80-mile crude oil pipeline between Midland and Colorado City, Texas that will provide an additional 250,000 barrels per day of capacity to supply connecting carriers at Colorado City.

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SouthTexas/Eagle Ford Area

Eagle Ford Area Systems. We own a 100% interest in and are the operator of several gathering systems that feed into our Gardendale Station, and we also own a 50% interest in and are the operator of the Eagle Ford joint venture pipeline. These Eagle Ford Area Systems consist of 439 miles of pipeline that service increasing production in the Eagle Ford shale play of South Texas and include approximately 2 million barrels of operational storage capacity across the system. The system serves the Three Rivers and Corpus Christi, Texas refineries and other markets via a marine terminal facility at Corpus Christi, as well as the Houston market via Enterprise Products Partners L.P. s (Enterprise) connection at Lyssy, Texas. For 2013, total average throughput on our Eagle Ford Area Systems was approximately 102,000 barrels per day.

In 2013, we and Enterprise announced an expansion of the Eagle Ford joint venture pipeline to increase the pipeline s capacity to 470,000 barrels per day. This expansion, which also includes the construction of an additional 2 million barrels of operational storage capacity, is expected to be in service in the second quarter of 2015.

Western

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 two outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system receives crude oil from ExxonMobil s Santa Ynez field at Las Flores and receives crude oil from the Freeport-McMoRan-operated Point Arguello field at Gaviota. The system terminates at our Emidio Station. 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.

A portion of our transportation segment profit on Line 63 and Line 2000 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 expected to decline.

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 144-mile trunk pipeline, originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The trunk pipeline has a capacity of approximately 110,000 barrels per day. The Line 63 system includes five miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and 148 miles of gathering pipelines in the San Joaquin Valley, with a throughput capacity of approximately 72,000 barrels per day. We also have 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. In 2013, we commenced a project to place this idle segment into service. We expect the project to be completed by mid-2015. For 2013, combined throughput on Line 63 totaled an average of approximately 52,000 barrels per day.

Line 2000. We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station (part of the All American Pipeline System) and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is an approximate 130-mile, 20-inch trunk pipeline with a throughput capacity of approximately 130,000 barrels per day. During 2013, throughput on Line 2000 (excluding Line 63 volumes) averaged approximately 61,000 barrels per day.

Rocky Mountain

Bakken Area Systems. We own and operate several gathering systems and pipelines that service crude oil production in Eastern Montana and Western North Dakota, and we also own a 22% interest in Butte Pipe Line. These Bakken Area Systems consist of 953 miles of pipeline, with total average throughput for 2013 of approximately 131,000 barrels per day.

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Salt Lake City Area Systems. We operate the Salt Lake City and Wahsatch pipeline systems, in which we own interests of between 75% and 100%. These systems include interstate and intrastate common carrier crude oil pipeline systems that transport crude oil produced in the U.S. Rocky Mountain region and Canada to refiners in Salt Lake City, Utah and to other pipelines at Ft. Laramie, Wyoming. These pipeline systems consist of 693 miles of pipelines and approximately one million barrels of storage capacity. These systems have a maximum throughput capacity of (i) approximately 20,000 barrels per day from Wamsutter, Wyoming to Ft. Laramie, Wyoming, (ii) approximately 49,000 barrels per day from Wamsutter, Wyoming to Wahsatch, Utah and (iii) approximately 120,000 barrels per day from Wahsatch, Utah to Salt Lake City, Utah. For 2013, throughput on these systems (excluding Frontier Pipeline) in total averaged approximately 124,000 barrels per day.

Included in the Salt Lake City Area systems is our 22% interest in Frontier Pipeline, an interstate common carrier crude oil pipeline that consists of a 289-mile trunk pipeline with a maximum throughput capacity of 79,000 barrels per day. Frontier Pipeline originates in Casper, Wyoming and delivers crude oil into the Wahsatch Pipeline System. For 2013, throughput on Frontier averaged approximately 7,000 barrels per day (attributable to our interest).

White Cliffs Pipeline. We own an approximate 36% interest in the White Cliffs Pipeline, a 527-mile, 12-inch common carrier pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma. Rose Rock Midstream, L.P. serves as the operator of the pipeline. For 2013, throughput on White Cliffs Pipeline averaged approximately 23,000 barrels per day (attributable to our interest). In 2012, White Cliffs announced an expansion project that will increase total system capacity from 70,000 barrels per day to 150,000 barrels per day and is underpinned by long-term shipper commitments. This expansion is expected to be completed in the first half of 2014.

Gulf Coast

Capline Pipeline System. The Capline Pipeline system, in which we own an aggregate undivided joint interest of approximately 54%, is a 631-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois.

Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, it has two active docks capable of handling approximately 600,000-barrel tankers and is connected to the Louisiana Offshore Oil Port and our St. James terminal and transports various grades of crude oil to PADD II. Total designed operating capacity is approximately 1.1 million barrels per day of crude oil, of which our attributable interest is approximately 600,000 barrels per day. Throughput on our interest averaged approximately 151,000 barrels per day during 2013.

Gulf Coast Pipeline. We are constructing our Gulf Coast Pipeline, an approximate 42-mile pipeline that originates at our Ten Mile facility in Alabama and extends to a refinery on the Gulf Coast. Additionally, we are constructing approximately 600,000 of storage capacity at our Ten Mile facility. We expect this project to be in service by mid-2014.

Central

Mid-Continent Area Systems. We own and operate pipeline systems that source crude oil from the Cleveland Sand, Granite Wash and Mississippian/Lime resource plays of Western and Central Oklahoma, Southwest Kansas and the eastern Texas Panhandle. These systems consist of approximately 2,300 miles of pipeline with transportation and delivery into and out of our terminal facilities at Cushing. For 2013, combined throughput on the Mid-Continent Area systems totaled an average of approximately 281,000 barrels per day.

Included in the Mid-Continent Area Systems is our Mississippian Lime pipeline, which was placed into service in August 2013. This new pipeline, which is supported by a long-term commitment from an area producer, services the increasing crude oil production in Northern Oklahoma and Southern Kansas and provides crude oil transportation to our terminal facilities at Cushing. We are currently constructing two expansions of the Mississippian Lime pipeline, including an approximate 55-mile extension from Coldwater in Comanche County, Kansas to Byron in Alfalfa County, Oklahoma, as well as an approximate 45-mile extension that will extend our pipeline infrastructure into Logan County and farther into Grant County, Oklahoma. Each of these expansions is expected to be brought into service in the first quarter of 2014 and is supported by a long-term commitment from an area producer.

Also in 2013, we commenced construction of a 95-mile extension of our existing Oklahoma crude oil pipeline system to service increasing production from producing areas in Western Oklahoma and the Texas Panhandle. This new Western Oklahoma pipeline will provide up to 75,000 barrels per day of new takeaway capacity from Reydon, Oklahoma to our existing Orion station in Major County, Oklahoma. This pipeline is supported by long-term producer commitments and is expected to be in service by the first quarter of 2014.

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Canada Pipelines

Crude Oil Pipelines

Manito. We own a 100% interest in the Manito heavy oil system. This 555-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line which delivers condensate to upstream blending locations. 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, and the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 137 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 and can both receive and deliver heavy crude from and to the Enbridge pipeline system. For 2013, approximately 46,000 barrels per day of crude oil were transported on the Manito system.

Rainbow System. We own a 100% interest in the Rainbow system. The Rainbow system is comprised of a 480-mile, 20-inch to 24-inch mainline crude oil pipeline extending from the Norman Wells Pipeline connection in Zama, Alberta to Edmonton, Alberta that has a throughput capacity of approximately 220,000 barrels per day and has 190 miles of gathering pipelines. In September 2013, we placed into service a 188-mile, 10-inch pipeline to transport diluent north from Edmonton, Alberta to our Nipisi truck terminal in Northern Alberta. This new pipeline has an initial capacity of 35,000 barrels per day and is expandable to 70,000 barrels per day. Total average throughput during 2013 on the Rainbow system was approximately 124,000 barrels per day.

Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system consists of a 670 mile, 8-inch to 16-inch mainline pipeline and 646 miles of 3-inch to 8-inch gathering pipelines. The Rangeland system transports NGL mix, butane, condensate, light sweet crude and light sour crude either north to Edmonton, Alberta or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. Total average throughput during 2013 on the Rangeland system was approximately 60,000 barrels per day.

South Saskatchewan. We own a 100% interest in the South Saskatchewan system. This system consists of a 160 mile, 16-inch mainline from Cantuar to Regina, Saskatchewan and 181 miles of 6-inch to 12-inch gathering pipelines from the Rapdan area to Cantuar. The South Saskatchewan system transports heavy crude oil from four gathering areas in southern Saskatchewan to Enbridge s Mainline at Regina. Total average throughput during 2013 on the South Saskatchewan system was approximately 51,000 barrels per day.

NGL Pipelines

Co-Ed NGL Pipeline System. We own a 100% interest in and are the operator of the Co-Ed NGL Pipeline System, which consists of approximately 772 miles of 3-inch to 10-inch pipeline. This pipeline gathers NGL from approximately 35 field gas processing plants located in Alberta, including all of the NGL produced at the Cochrane Straddle Plant. The Co-Ed NGL Pipeline System has throughput capacity of approximately 72,000 barrels per day. During 2013, throughput averaged approximately 56,000 barrels per day.

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, NGL and natural gas, NGL fractionation and isomerization services and natural gas and condensate processing 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) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and redeliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (v) revenues from the sale of natural gas, (vi) fees from NGL fractionation and isomerization and (vii) fees from natural gas and condensate processing services.

As of December 31, 2013, we owned, operated or employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

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- approximately 74 million barrels of crude oil and refined products storage capacity primarily at our terminalling and storage locations;
- approximately 23 million barrels of NGL storage capacity;
- approximately 97 Bcf of natural gas storage working capacity;
- approximately 17 Bcf of owned base gas;
- 11 natural gas processing plants located throughout Canada and the Gulf Coast area of the United States;
- a condensate stabilization facility located in the Eagle Ford area of South Texas with an aggregate processing capacity of approximately 80,000 barrels per day;
- seven fractionation plants located throughout Canada and the United States with an aggregate gross processing capacity of approximately 221,800 barrels per day, and an isomerization and fractionation facility in California with an aggregate processing capacity of approximately 14,000 barrels per day;
- 24 crude oil and NGL rail terminals located throughout the United States and Canada. See -Major Facilities Assets - Rail Facilities below for an overview of various terminals and Supply and Logistics regarding our use of railcars; and
- approximately 1,250 miles of active pipelines that support our facilities assets, consisting primarily of NGL and natural gas pipelines.

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The following is a tabular presentation of our active facilities segment storage and service assets in the United States and Canada as of December 31, 2013, grouped by product and service type and capacity and volume as indicated:

Crude Oil and Refined Products Storage Facilities	**Total Capacity (MMBbls)**
Cushing	20
Kerrobert	1
LA Basin	8
Martinez and Richmond	5
Mobile and Ten Mile	2
Patoka	6
Philadelphia Area	4
St. James	9
Yorktown (1)	6
Other	13
	74

NGL Storage Facilities	**Total Capacity (MMBbls)**
Bumstead	4
Fort Saskatchewan	4
Sarnia Area	8
Tirzah	1
Other	6
	23

Natural Gas Storage Facilities	**Total Capacity (Bcf)**
Salt-caverns and Depleted Reservoir	97

Natural Gas Processing Facilities (2)	**Ownership Interest**	**Total Gas Inlet Volume (3) (Bcf/d)**	**Gross Gas Processing Capacity (Bcf/d)**	**Net Gas Processing Capacity (Bcf/d)**
United States Gulf Coast Area	100%	0.2	0.6	0.6
Canada	36-100%	1.3	6.7	5.4
		1.5	7.3	6.0

Condensate Stabilization Facility	**Total Capacity (Bpd)**
Gardendale	80,000

NGL Fractionation and Isomerization Facilities	**Ownership Interest**	**Total Inlet Volume (3) (Bpd)**	**Gross Capacity (Bpd)**	**Net Capacity (Bpd)**
Fort Saskatchewan	21-100%	23,332	75,000	51,300
Sarnia	62-84%	53,788	120,000	90,000
Shafter	100%	8,951	14,000	14,000

Other	82-100%	10,255	26,800	24,973
		96,326	235,800	180,273

Rail Facilities	**Ownership Interest**	**Loading Capacity (4) (Bpd)**	**Unloading Capacity (4) (Bpd)**
Crude Oil Rail Facilities	100%	211,000	280,000

	Ownership Interest	**Number of Rack Spots**	**Number of Storage Spots**
NGL Rail Facilities (5)	50-100%	247	1,135

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(1) Amount includes 1.6 million barrels of capacity for which we hold lease options (1.1 million barrels of which have been exercised).

(2) While natural gas processing inlet volumes and capacity amounts are presented, they currently are not a significant driver of our segment results.

(3) Inlet volumes represent average inlet volumes net to our share for the entire year.

(4) Capacity transported will vary according to specification of product moved.

(5) Our NGL rail terminals are predominately utilized for internal purposes specifically for our supply and logistics activities. See our -Supply and Logistics Segment discussion following this section for further discussion regarding the use of our rail terminals.

The following discussion contains a detailed description of our more significant facilities segment assets.

Major Facilities Assets

Crude Oil and Refined Products Facilities

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 United States 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 source of refinery feedstock for Midwest and Gulf Coast refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. The facility has access to all major inbound and outbound pipelines in Cushing and is designed to handle multiple grades of crude oil while minimizing the interface and enabling deliveries to connecting carriers at their maximum rate.

Since 1999, we have completed multiple expansions, which have increased the capacity of the Cushing Terminal to a total of approximately 20 million barrels. During 2013, we added approximately 1.1 million barrels of such storage capacity through the construction of four 270,000 barrel tanks. We also added additional delivery capacity through the installation of a high volume meter. During mid-2013, we commenced construction of an additional 0.5 million barrels of storage capacity, which is expected to be placed into service in stages throughout 2014.

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. The total storage capacity at the Kerrobert terminal is approximately 1 million barrels. This facility is also connected to the Enbridge pipeline system and can both receive and deliver heavy crude from and to the Enbridge pipeline system.

L.A. Basin. We own four crude oil and refined product storage facilities in the Los Angeles area with a total of approximately 8 million barrels of storage capacity in commercial service and a distribution pipeline system of approximately 50 miles of pipeline in the Los Angeles Basin. 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. Our Los Angeles area system s pipeline distribution assets connect our storage assets with major refineries and third-party pipelines and marine terminals in the Los Angeles Basin.

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 and our Richmond terminal is also able to receive products by rail.

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 2 million barrels of additional storage capacity is available at our nearby Ten Mile Facility, which is connected to our Mobile Terminal via a 36-inch pipeline. Approximately half of the additional storage capacity at Ten Mile is included in our 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 6 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. Our terminal is connected to all major pipelines and terminals at the patoka interchange. Patoka is a growing regional hub with access to domestic and foreign crude oil for certain volumes moving north on the Capline system as well as Canadian barrels moving south.

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. The Philadelphia area terminals also receive products from connecting pipelines.

St. James Terminal. We have approximately 9 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 is connected to major pipelines and other terminals and includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. Over the past few years, we completed the construction of a marine dock that is able to receive from tankers and receive from, and load, barges. The facility is also connected to our rail unloading facility. See -Rail Facilities below for further discussion.

In 2013, we added approximately 0.6 million barrels of crude oil storage capacity to the St. James terminal, and we expect to add approximately 1.1 million barrels of crude oil storage capacity throughout 2014. These expansions are supported by multi-year contracts and throughput arrangements with third-party customers.

Yorktown Terminal. We have approximately 6 million barrels of storage for crude oil, black oil, propane, butane and refined products at the Yorktown facility, including 1.6 million barrels of capacity for which we hold lease options (1.1 million barrels of which have been exercised). The Yorktown facility has its own deep-water port on the York River with the capacity to service the receipt and delivery of product from ships and barges. This facility also has an active truck rack and rail capacity. See -Rail Facilities below for further discussion. We are in the process of making a number of modifications to the Yorktown facility, which will enhance the capabilities of the rail system, the dock facilities and related infrastructure, and increase connectivity and flexibility within the terminal itself. Portions of these projects were completed in the fourth quarter of 2013, with the balance expected to be completed in early 2014.

NGL Storage Facilities

Bumstead. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With approximately 4 million barrels of useable capacity, the facility s primary assets include three salt-dome storage caverns, a 30-car rail rack and six truck racks.

Fort Saskatchewan. The Fort Saskatchewan facility is located approximately 16 miles northeast of Edmonton, Alberta in one of the key North American NGL hubs. The facility is a receipt, storage, fractionation and delivery facility for NGL and is connected to other major NGL plants and pipeline systems in the area. The facility s primary assets include 21 storage caverns with approximately 4 million barrels in useable storage capacity. NGL mix and spec products can be delivered to the Enbridge pipeline in addition to the propane truck loading rack at the facility. The facility includes assets operated by us and assets operated by a third-party. Our ownership in the various facility assets ranges from approximately 21% to 100%. See the section entitled NGL Fractionation and Isomerization Facilities below for additional discussion of this facility.

During 2013, we began upgrading our Fort Saskatchewan storage capacity as part of a multi-phase expansion. The first phase of the expansion will add two additional NGL storage caverns and approximately 2.5 million barrels of additional brine pond capacity.

Sarnia Area. The Sarnia facility is a large NGL fractionation, storage and shipping facility located on a 380 acre plant site in the Sarnia Chemical Valley. There are 36 multi-product rail car loading spots, 4 multi-product truck loading racks and a network of 14 pipelines providing product delivery capabilities to our Windsor, St. Clair and Green Springs terminal facilities, in addition to refineries, chemical plants, and other pipeline systems in the area. The facility has approximately 3 million barrels in useable storage capacity. In 2013, we initiated a brine disposal program which will facilitate the removal of excess brine via truck from our Sarnia facility. The project is expected to increase useable NGL storage capacity at the facility by as much as 3 million barrels when completed.

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The Windsor storage terminal in Windsor, Canada, is a pipeline hub and underground storage facility. The facility is served by three Plains owned receipt/dispatch pipelines, the Cochin pipeline and rail and truck offloading. There are eight storage caverns on site with a useable capacity of approximately 3 million barrels. The primary terminal assets consist of 16 multi-product rail tank car loading spots and a propane truck loading rack. In 2014, we plan to initiate a brine disposal program which will facilitate the removal of excess brine via pipeline from our Windsor storage terminal. The project is expected to increase useable NGL storage capacity at the facility by approximately 1 million barrels.

The St. Clair terminal is a propane, isobutane and butane storage and distribution facility located in St. Clair, Michigan and is connected to the Sarnia facility via a Plains owned pipeline. On site are seven storage caverns with useable capacity of approximately 2 million barrels and 28 multi-product rail tank car loading spots.

Tirzah. The Tirzah facility is located in South Carolina and consists of an underground granite storage cavern with approximately 1 million barrels of useable capacity. The Tirzah facility is connected to the Dixie Pipeline System (a third-party system) via our 62-mile pipeline.

Natural Gas Storage Facilities

We own three FERC regulated natural gas storage facilities located in the Gulf Coast and Midwest that are permitted for 149 Bcf of working gas capacity, and as of December 31, 2013, we had an aggregate working gas capacity of approximately 97 Bcf in service. Our facilities have aggregate peak daily injection and withdrawal rates of 4.1 Bcf and 6.4 Bcf, respectively.

Our natural gas storage facilities are strategically located and have a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and liquefied natural gas (LNG) exporters, whose storage needs vary from traditional seasonal storage services to hourly balancing. We are located near several major market hubs, including the Henry Hub (the delivery point for NYMEX natural gas futures contracts), the Carthage Hub (located in East Texas), the Perryville Hub (located in North Louisiana), and the major market hubs of Chicago, Illinois and Dawn, Ontario. Our facilities service consumer and industrial markets in the Gulf Coast, Midwest, Mid-Atlantic, Northeast, and Southeast regions of the United States and the Southeastern portion of Canada through 19 interconnects with 12 interstate pipelines and 4 utility companies.

Natural Gas Processing Facilities

We own and operate five natural gas processing plants located in Louisiana and Alabama with an aggregate natural gas processing capacity of approximately 0.6 Bcf per day. In 2013, we completed a number of modifications to our Patterson, Louisiana gas processing facility, which included new pipeline and customer connections.

We also own and/or operate four straddle plants and two field gas processing plants located in Western Canada with an aggregate gross natural gas processing capacity of approximately 6.7 Bcf per day and long-term liquid supply contracts relating to a third-party owned straddle plant with gross processing capacity of approximately 2.5 Bcf per day.

Condensate Stabilization Facility

In February 2013, we completed construction of a condensate stabilization facility in La Salle County, Texas which is designed to extract natural gas liquids from condensate. The facility, which currently has two stabilizers and a capacity of 80,000 barrels per day, is adjacent to our Gardendale terminal and rail facility. Throughput at the Gardendale stabilization facility is supplied by long-term commitments from producers. Since the facility began operations, throughput has averaged approximately 40,000 barrels per day.

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In 2013, we announced that we will add a third condensate stabilizer that will provide approximately 40,000 barrels per day of incremental capacity to the existing facility, bringing the total capacity to approximately 120,000 barrels per day. This project is expected to be in service in the second quarter of 2015.

NGL Fractionation and Isomerization Facilities

Fort Saskatchewan. Our Fort Saskatchewan facility has a fractionation capacity of approximately 45,000 barrels per day and produces both spec NGL products and C3/C4 mix for delivery to the Sarnia facility via the Enbridge pipeline.

The fractionation feedstock is supplied via the Fort Saskatchewan Pipeline System which connects to the Co-Ed NGL Pipeline System. Through ownership in the Keyera Fort Saskatchewan fractionation plant, (which has a gross fractionation capacity of 30,000 barrels per day), we have additional fractionation capacity, net to our share of 6,300 barrels per day.

Sarnia. The Sarnia Fractionator is the largest fractionation plant in Eastern Canada and receives NGL feedstock from the Enbridge Pipeline, the Kalkaska Pipeline, and from refineries, gas plants and chemical plants in the area. The fractionation unit has a gross useable capacity of 120,000 barrels per day and produces specification propane, isobutane, normal butane and natural gasoline. Our ownership in the various processing units at the Sarnia Fractionator ranges from 62% to 84%.

Shafter. Our Shafter facility located near Bakersfield, California provides isomerization and fractionation services to producers and customers. The primary assets consist of approximately 200,000 barrels of NGL storage and a processing facility with butane isomerization capacity of approximately 14,000 barrels per day and NGL fractionation capacity of approximately 12,000 barrels per day.

During the fourth quarter of 2013, we completed construction of a 15-mile NGL pipeline system that is capable of delivering up to 10,000 barrels per day from Occidental Petroleum Corporation s Elk Hills Gas plant to our Shafter facility. This project also included additions to our storage capacity and rail facilities.

Gardendale. In 2013, we announced a project to construct a new NGL fractionator in the Eagle Ford area of South Texas that will have a capacity of up to 15,000 barrels per day of NGL Y-Grade and off-spec Y-Grade product. The fractionator will be located near existing PAA assets in Gardendale (La Salle County), Texas, and will be designed to fractionate NGL Y-Grade and to treat and fractionate off-spec Y-Grade sourced from our area gathering system, our condensate stabilizer and throughout the Eagle Ford producing region. This project, which is supported by long-term third-party commitments, will also include the construction of approximately 80,000 barrels of pressurized storage to accommodate Y-Grade and purity products and is expected to be in service in the second quarter of 2015.

Rail Facilities

Crude Oil Rail Loading Facilities

We own five active crude oil and condensate rail loading terminals that service production in the Niobrara, Eagle Ford and Bakken shale formations and have a combined loading capacity of approximately 211,000 barrels per day. These facilities are located in Carr, Colorado; Tampa, Colorado; Gardendale, Texas; Manitou, North Dakota; and Van Hook, North Dakota. We placed the Tampa, Colorado facility into service in November 2013.

We are currently expanding our Van Hook and Carr terminals to increase loading capacity at each terminal from 35,000 and 15,000 barrels per day, respectively, to 68,000 barrels per day. We expect to complete these expansions in mid-2014 and the first half of 2015, respectively. In addition, we are currently constructing crude oil rail loading facilities in Western Canada, which we expect to be in service in mid-2015.

Crude Oil Rail Unloading Facilities

We own two active crude oil rail unloading terminals and have one additional unloading terminal under construction. Our terminal at St. James, Louisiana is connected to our active rail unloading facility that has an unload capacity of 140,000 barrels of sweet crude oil per day. Our Yorktown, Virginia rail facility was placed into service in December 2013. This facility receives unit trains and has an unload capacity of approximately 140,000 barrels per day.

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In connection with our 2012 acquisition of rail terminals from US Development Group, we acquired a project to construct a crude oil unloading terminal near Bakersfield, California. We expect to complete this project during the second half of 2014, at which point this terminal will have permitted capacity to unload 70,000 barrels per day.

NGL Rail Facilities

We own nineteen operational NGL rail facilities located throughout the United States and Canada that are strategically located near NGL storage, pipelines, gas production or propane distribution centers. Our NGL rail facilities currently have 247 railcar rack spots and 1,135 railcar storage spots and we have the ability to switch our own rail cars at six of these terminals.

Supply and Logistics Segment

Our supply and logistics segment operations generally consist of the following merchant-related activities:

- the purchase of U.S. and Canadian crude oil at the wellhead, the bulk purchase of crude oil at pipeline, terminal and rail facilities, and the purchase of cargos at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of NGL;
- the purchase of NGL from producers, refiners, processors and other marketers;
- the resale or exchange of crude oil and NGL at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and ocean-going vessels from various delivery points, market hub locations or directly to end users such as refineries, processors and fractionation facilities.

We characterize a substantial portion of our baseline segment profit generated by our Supply and Logistics segment as fee equivalent. This portion of the segment profit is generated by the purchase and resale of crude oil on an index-related basis, which results in us generating a gross margin for such activities. This gross margin is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil to market as well as any operating and general and administrative expenses. The level of profit associated with a portion of the other activities we conduct in the Supply and Logistics segment is influenced by overall market structure and the degree of market volatility, as well as variable operating expenses. The majority of activities that are carried out within our supply and logistics segment are designed to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside potential associated with opportunities inherent in volatile market conditions (including opportunities to benefit from fluctuating differentials). These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a balance. The tankage that is used to support our arbitrage activities positions us to capture margins in a contango market or when the market switches from contango to backwardation. See Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model below for further discussion.

In addition to substantial working inventories associated with its merchant activities, as of December 31, 2013, our supply and logistics segment also owned significant volumes of crude oil and NGL classified as long-term assets for linefill or minimum inventory requirements and employs a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 12 million barrels of crude oil and NGL linefill in pipelines owned by us;
- 4 million barrels of crude oil and NGL linefill in pipelines owned by third parties and other long-term inventory;
- 843 trucks and 982 trailers; and
- 7,400 crude oil and NGL 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, generally under longer term arrangements.

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The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2013 (in thousands of barrels per day):

	Volumes
Crude oil lease gathering purchases	859
NGL sales	215
Waterborne cargos	4
Supply and Logistics activities total	1,078

Crude Oil and NGL Purchases. We purchase crude oil and NGL from multiple producers under contracts and believe that we have established long-term, broad-based relationships with the crude oil and NGL producers in our areas of operations. Our crude oil contracts generally range in term from thirty-day evergreen to five years, with the majority ranging from thirty days to one year and a limited number of contracts extending up to eight years. We utilize our truck fleet and gathering pipelines as well as leased railcars, 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 United States or we may purchase crude oil in foreign locations and transport it on third-party tankers.

We purchase NGL from producers, refiners, and other NGL marketing companies under contracts that typically have ranged from immediate delivery to one year in term. With the shortage of fractionation and storage space in Western Canada, we are pursuing an increasing number of contracts with five to 10 year terms to firm up capacity utilization and base-load expansion projects. We utilize our trucking fleet and pipeline network, as well as leased railcars, third-party tank trucks and third-party pipelines to transport NGL.

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 NGL in bulk at major pipeline terminal points and storage facilities from major integrated oil companies, large independent producers or other NGL marketing companies or processors. Crude oil and NGL are purchased in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or NGL 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 NGL Sales. The activities involved in the supply, logistics and distribution of crude oil and NGL are complex and require current detailed knowledge of crude oil and NGL sources and end markets, as well as 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 NGL 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. We sell NGL primarily to propane and refined product retailers, petrochemical companies and refiners, and limited volumes to other marketers. A majority of our crude oil and NGL contracts generally range in term from a thirty-day evergreen to one year terms. We establish a margin for the crude oil and NGL 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 NGL-related futures contracts as hedging devices.

Crude Oil and NGL 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 NGL that more closely matches our physical delivery requirement, location or the preferences of our customers, we exchange physical crude oil or NGL, 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 NGL that differs in terms of geographic location, grade of crude oil or type of NGL, or physical delivery schedule from crude oil or NGL we have available for sale. Generally, we enter into exchanges to acquire crude oil or NGL at locations that are closer to our end markets, thereby reducing transportation costs and increasing our margin. We also exchange our crude oil to be physically delivered at a later date, if the exchange is expected to result in a higher margin net of storage costs, and enter into exchanges based on the grade of crude oil, which includes such factors as sulfur content and specific gravity, in order to meet the quality specifications of our physical delivery contracts. See Note 2 to our Consolidated Financial Statements for further discussion of our accounting for exchange and buy/sell agreements.

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Credit. Our merchant activities involve the purchase of crude oil, NGL, natural gas 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 hedged inventory facility or our senior unsecured revolving credit facility.

When we sell crude oil, NGL, natural gas 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, prepayment, letters of credit and monitoring procedures.

Because our typical sales transactions can involve large volumes of crude oil and natural gas, 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 and natural gas 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 NGL (principally propane); 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 NGL on a forward basis, as well as to sell NGL on a current basis to local distributors and retailers. In certain cases our NGL customers prepay for their purchases, in amounts ranging up to 100% of their contracted amounts.

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

Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model

Through our three business segments, we are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products, NGL and natural gas. The majority of our activities are focused on crude oil, which is the principal feedstock used by refineries in the production of transportation fuels.

Crude oil, NGL, natural gas and refined products commodity prices have historically been very volatile. For example, since the mid-1980s, NYMEX West Texas Intermediate crude oil benchmark prices have ranged from a low of approximately $10 per barrel during 1986 to a high of over $147 per barrel during 2008. During 2013, West Texas Intermediate crude oil prices traded within a range of $87 to $111 per barrel.

Absent extended periods of lower crude oil prices that are below production replacement costs or higher crude oil prices that have a significant adverse impact on consumption, demand for the services we provide in our fee-based transportation and facilities segments and our gross profit from these activities have little correlation to absolute crude oil prices. Relative contribution levels will vary from quarter-to-quarter due to seasonal and other similar factors, but our fee-based transportation and facilities segments should comprise approximately 70% to 80% of our aggregate base level segment profit.

Base level segment profit from our supply and logistics activities is dependent on our ability to sell crude oil and NGL at prices in excess of our aggregate cost. Although segment profit may be adversely affected during certain 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.

In developing our business model and allocating our resources among our three segments, we attempt to anticipate the impacts of shifts between supply-driven markets and demand-driven markets, seasonality, cyclicality, regional surpluses and shortages, economic conditions and a number of other influences that can cause volatility and change market dynamics on a short, intermediate and long-term basis. Our objective is to position the Partnership such that our overall annual base level of cash flow is not materially adversely affected by the absolute level of energy prices, shifts between demand-driven markets and supply-driven markets or other similar dynamics. We believe the complementary, balanced nature of our business activities and diversification of our asset base among varying regions and demand-driven and supply-driven markets provides us with a durable base level of cash flow in a variety of market scenarios.

In addition to providing a durable base level of cash flow, this approach is also intended to provide opportunities to realize incremental margin during volatile market conditions. For example, if crude oil prices are high relative to historical levels, we may hedge some of our expected pipeline loss allowance barrels, and if crude oil prices are low relative to historical prices, we may hedge a portion of our anticipated diesel purchases needed to operate our trucks and barges. Also, during periods when supply exceeds the demand for crude oil, NGL or natural gas in the near term, the market for such product is often in contango, meaning that the price for future deliveries is higher than current prices. In a contango market, entities that have access to storage at major trading locations can purchase crude oil, NGL or natural gas at current prices for storage and simultaneously sell forward such products for future delivery at higher prices. Conversely, when there is a higher demand than supply of crude oil, NGL or natural gas in the near term, the market is backwardated, meaning that the price for future deliveries is lower than current prices. In a backwardated market, hedged positions established in a contango market can be unwound, with the physical product or futures position sold into the current higher priced market at a level that mitigates losses associated with closing out future delivery obligations.

The combination of a high level of fee-based cash flow from our transportation and facilities segments, complemented by a number of diverse, flexible and counter-balanced sources of cash flow within our supply and logistics segment is intended to enable us to accomplish our objectives of maintaining a durable base level of cash flow and providing upside opportunities. In executing this business model, we employ a variety of financial risk management tools and techniques, predominantly in our supply and logistics segment.

Risk Management

In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations and, in certain circumstances, to realize incremental margin during volatile market conditions, we use derivative instruments. We also use various derivative instruments to manage our exposure to interest rate risk and currency exchange rate risk. 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 management s assessment of the cost or benefit 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 commodity 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. Our interest rate and currency exchange rate risk management policies and procedures are designed to monitor our derivative positions and ensure that those positions are consistent with our objectives and approved strategies. 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.

Except for pre-defined inventory positions, our policy is generally to structure our purchase and sales contracts so that price fluctuations do not materially affect our operating income, and not to acquire and hold physical inventory or derivatives for the purpose of speculating on outright commodity price changes.

Although we seek to maintain a position that is substantially balanced within our supply and logistics activities, we purchase crude oil, refined products, NGL and natural gas 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 18 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Corporation and its subsidiaries accounted for approximately 15% of our revenues for the year ended December 31, 2013 and approximately 16% of our revenues for each of the years ended December 31, 2012 and 2011. ExxonMobil Corporation and its subsidiaries accounted for approximately 13%, 13% and 10% of our revenues for the years ended December 31, 2013, 2012 and 2011, respectively. Phillips 66 and its subsidiaries accounted for approximately 11% of our revenues for the year ended December 31, 2013. ConocoPhillips Company (prior to the spin-off of Phillips 66, which was effective May 1, 2012) accounted for approximately 10% of our revenues for the year ended December 31, 2011. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2013, 2012 and 2011. The majority of revenues from these customers pertain to our supply and logistics operations. The sales to these customers occur at multiple locations and 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 13 to our Consolidated Financial Statements.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and supply regions and demand for the crude oil and NGL 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 cost of moving an incremental barrel of crude oil or NGL. In addition, in areas where additional infrastructure is necessary to accommodate new or increased production or changing product flows, we face competition in providing the required infrastructure solutions as well as the risk of building capacity in excess of sustained demand. Depending upon the specific movement, pipelines, which generally offer the lowest cost of transportation, may also face competition from other forms of transportation, such as rail and barge. Although these alternative forms of transportation are typically higher cost, they can provide access to alternative markets at which a higher price may be realized for the commodity being transported, thereby overcoming the increased transportation cost.

We also face competition with respect to our supply and logistics and facilities services. Our competitors include other crude oil and NGL pipeline companies, other NGL processing and fractionation companies, the major integrated oil companies, their marketing affiliates and independent gatherers, banks that have established a trading platform, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources greater than ours.

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 pipeline companies 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 and/or enforcement actions. In 2010 we settled by means of separate Consent Decrees, two Department of Justice (DOJ)/Environmental Protection Agency (EPA) proceedings regarding certain releases of crude oil. One Consent Decree applied to our crude oil pipelines in general and was terminated in November 2013. The remaining Consent Decree applies to a specific system. Although we believe that all material aspects of the injunctive elements of the remaining Consent Decree (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings could result in additional injunctive remedies, the effect of which would subject us to operational requirements and constraints that would not apply to our competitors.

The 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 (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.

United States

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. These amendments have resulted in the adoption of rules by the Department of Transportation (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. In the United States, our costs associated with the inspection, testing and correction of identified anomalies were approximately $57 million in 2013, $39 million in 2012 and $32 million in 2011. Based on currently available information, our preliminary estimate for 2014 is that we will incur approximately $25 million in operational expenditures and approximately $52 million in capital expenditures associated with our required pipeline integrity management program. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented. Currently, we believe our pipelines are in substantial compliance with HLPSA and the 2002 and 2006 amendments. In addition to required activities, our integrity management program includes several internal programs designed to prevent incidents and includes activities such as automating valves and replacing river crossings. Costs incurred for such activities were approximately $22 million in 2013, $24 million in 2012 and $22 million in 2011, and our preliminary estimate for 2014 is that we will incur approximately $47 million.

On December 13, 2011, the United States Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act). The President signed the Act into law on January 3, 2012. Under the Act, maximum civil penalties for certain violations have been increased from $100,000 to $200,000 per violation per day, and from a total cap of $1 million to $2 million. In addition, the Act reauthorizes the federal pipeline safety programs of PHMSA through September 30, 2015, and directs the Secretary of Transportation to undertake a number of reviews, studies and reports, some of which may result in additional natural gas and hazardous liquids pipeline safety rulemaking.

A number of the provisions of the Act have the potential to cause owners and operators of pipeline facilities to incur significant capital expenditures and/or operating costs. Any additional requirements resulting from these directives are not expected to impact us differently than our competitors. We will work closely with our industry associations to participate with and monitor DOT-PHMSA s efforts.

We have an internal review process in which we examine the condition and operating history of our pipelines and gathering assets to determine if any of our 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. 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.

If approved by PHMSA, states may assume responsibility for enforcing federal interstate pipeline regulations as agents for PHMSA and conduct inspections of intrastate pipelines. In practice, states vary in their authority and capacity to address pipeline safety. We do not anticipate any significant issues 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. In the United States, costs associated with this program were approximately $26 million, $31 million and $22 million in 2013, 2012 and 2011, respectively. For 2014, we have budgeted approximately $34 million in connection with continued API 653 compliance activities and similar new EPA regulations for tanks not regulated by the DOT. 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.

Canada

In Canada, the NEB and provincial agencies such as the Alberta Energy Regulator (f/k/a the Energy Resources Conservation Board) (AER) and the Saskatchewan Ministry of Economy regulate the safety and integrity management of pipelines and storage tanks used for hydrocarbon transmission. We have incurred and will continue to incur costs related to such regulatory requirements. In 2013 the AER issued an order under Section 22 of the Oil and Gas Conservation Act imposing additional regulatory requirements on PMC with respect to obtaining operating approvals under such Act and ordering an audit of PMC s operations. Although we believe that all material aspects of the order (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings could result in additional operational requirements and constraints that would not apply to our competitors. In addition to required activities, our integrity management program includes several internal programs designed to prevent incidents and includes activities such as upgrades to our operating and maintenance programs and systems and upgrades to our pipeline watercourse crossing integrity program. Between such required and elective activities we spent approximately $90 million in 2013, $80 million in 2012 and $35 million in 2011. Our preliminary estimate for 2014 is approximately $106 million. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented.

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. Since asset acquisitions are an integral part of our business strategy, as we acquire additional assets, we may be required to incur additional costs to ensure that the acquired assets comply with the regulatory standards in the United States and Canada.

Occupational Safety and Health

United States

In the United States, 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. Certain of our facilities are subject to OSHA Process Safety Management (PSM) regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals.

These regulations apply to any process which involves a chemical at or above specified thresholds or any process that involves 10,000 pounds or more of a flammable liquid or gas in one location. 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.

Canada

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts, Regulations and Codes. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or investigation of a public or employee complaint. In some jurisdictions, the agencies have been empowered to administer penalties for contraventions without the company first being prosecuted. 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. Canadian and provincial laws also impose liabilities for releases of certain substances into the environment.

We are subject to the EPA s Risk Management Plan regulations at certain facilities. These regulations are intended to work with OSHA s PSM regulations (see -Occupational Safety and Health above) to minimize the offsite consequences of catastrophic releases. The regulations require us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in substantial compliance with our risk management program.

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.

Assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We have in the past experienced and in the future will likely experience releases of crude oil into the environment from our pipeline and storage operations. We may also discover environmental impacts from past releases that were previously unidentified.

Air Emissions

Our United States operations are subject to the United States Clean Air Act (Clean Air Act), comparable state laws and associated state and federal regulations. Our Canadian operations are subject to federal and provincial air emission regulations. The new Canadian standards for air quality and industrial air emissions were implemented in May 2013. The new standards provide more stringent objectives for outdoor air quality, including for the first time in Canada, a long term (annual) target for fine particulate matter. Under these laws, permits may be required before construction can commence on a new or modified 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 federal, state, provincial and regional air emissions control requirements 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.

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Climate Change Initiatives

United States

A number of studies have been conducted by various parties which represent to be authoritative on the issue of emissions of carbon dioxide and certain other gases, generally referred to as greenhouse gases (GHG). Many of these studies draw conflicting conclusions as to whether GHG is contributing to warming of the Earth s atmosphere. In 2009, the U.S. EPA adopted rules for establishing a GHG emissions reporting program. Fewer than ten of our facilities are presently subject to the federal GHG reporting requirements. These include facilities with combustion GHG emissions and potential fugitive emissions above the reporting thresholds. We import sufficient quantities of finished fuel products into the United States to be required to report that activity as well. We also continue to monitor GHG emissions for all of our facilities and activities. At the present time, we do not anticipate the need to purchase a material amount of GHG credits or install control technology to reduce GHG emissions at any of our facilities.

In 2010, the EPA promulgated regulations establishing Title V and Prevention of Significant Deterioration permitting requirements for large sources of GHGs. Fewer than ten of our existing facilities are potential major sources of GHG subject to these permitting requirements. We may be required to install best available control technology to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs. The EPA is in the process of identifying what constitutes best available control technology for various sources of GHG emissions, but it appears likely that the agency will seek to impose energy efficiency requirements on sources that burn large volumes of fossil fuels rather than post-combustion GHG capture requirements. If the EPA imposes energy efficiency requirements, we do not anticipate that they will have an adverse effect on the cost of our operations.

In the absence of federal climate legislation in the United States, a number of regional efforts have emerged aimed at reducing GHG emissions. Two of the more significant non-federal GHG programs are the Regional Greenhouse Gas Initiative (RGGI) and the Western Climate Initiative (WCI). RGGI, which includes a number of states in the northeastern United States, implemented a cap-and-trade program in 2009. At present, this program only applies to utility power plants. None of our facilities are affected by RGGI.

The WCI originally included several U.S. states and Canadian provinces, either as full voting members or observers. Most U.S. states have withdrawn from WCI, with California the sole remaining member from the United States. California has implemented a GHG cap-and-trade program, authorized under Assembly Bill 32 (AB32). The California Air Resources Board has published a list of facilities expected to be subject to this program. At this time, the list only includes one of our facilities, the Lone Star Gas Liquids facility in Shafter, California. The rules implementing the AB32 program were finalized in December 2011, and the first auction of GHG emission credits was conducted in the fall of 2012, with the average credit selling for $10.09 per ton. The compliance requirements of the GHG cap-and-trade program through 2020 are being phased in, and we do not anticipate any problems in complying with those obligations going forward or for such impacts to be material. The California Air Resources Board is currently developing a scoping plan for AB-32 compliance obligations after the year 2020.

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, demand for our services, financial condition, 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.

The operations of our refinery customers could also be negatively impacted by current GHG legislation or new regulations resulting in increased operating or compliance costs. Some of the proposed federal and state   cap-and-trade   legislation would require businesses that emit GHGs to buy emission credits from government, other businesses, or through an auction process. In addition, refiners could be required to purchase emission credits for GHG emissions resulting from their own refining operations as well as the fuels they sell. While it is not possible at this time to predict the final form of   cap-and-trade   legislation, any new federal or state restrictions on GHG emissions could result in material increased compliance costs, additional operating restrictions and an increase in the cost of feedstock and products produced by our refinery customers.

Canada

Pursuant to the 1997 United Nations Framework Convention on Climate Change, also known as the   Kyoto Protocol , many nations, including Canada, agreed to limit emissions of GHGs. The Kyoto Protocol required Canada to reduce its emissions of GHG to 6% below 1990 levels by 2012. However, by 2009, emissions in Canada were 17% higher than 1990 levels. In December 2011, Canada withdrew from the Kyoto Protocol, but signed the   Durban Platform   committing it to a legally binding treaty to reduce GHG emissions, the terms of which are to be defined by 2015 and are to become effective in 2020.

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In 2007, in response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (also known as the Turning the Corner measures), a regulatory framework for monitoring industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Originally, this framework was intended to be implemented by 2010; however no federally mandated reduction targets for GHGs have been implemented to date. Since 2004, companies emitting more than 100 thousand tons per year (kt/y) of CO_2 equivalent (CO_2e) were required to report their GHG emissions under the Greenhouse Gas Emissions Reporting Program. In 2010, this reporting threshold was reduced to 50 kt/y. Two PMC facilities meet this reporting threshold.

In Alberta, the provincial government implemented the Specified Gas Emitter Regulation in 2007 (under the Alberta Environment Protection and Enhancement Act), which mandated a 12% reduction in emission intensity over the established baseline level (average of the 2003-2005 levels) for all facilities emitting more than 100kt/y of CO_2e. Since the regulation came into effect, PMC has had one facility (Fort Saskatchewan Storage and Fractionation Facility) which currently does not meet the reduction obligation. As such, PMC has been required to submit compliance credits which have been completed by submitting payment to the Climate Change Emissions Management Fund. Alberta also has a GHG reporting threshold at 50kt/y of CO_2e.

With regard to the oil and gas industry and the pipeline transportation sector, it is unclear at this time what direction the government plans to take. However, given that there have been no specific regulatory changes announced to date regarding GHG emissions reduction in these sectors; any future initiatives would likely not take effect until beyond 2015.

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 above and Note 16 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.

With respect to our new pipeline construction activities and maintenance on our existing pipelines, Section 404 of the CWA authorizes the Army Corps of Engineers (Corps) to permit the discharge of dredged or fill materials into navigable waters, which are defined as the waters of the United States. Section 404 (e) authorizes the Corps to issue permits on a nationwide basis for categories of discharges that have no more than minimal individual or cumulative environmental effects. For the past 35 years, the Corps has authorized construction, maintenance and repair of pipelines under a streamlined nationwide permit program known as Nationwide Permit 12 (NWP). NWP is supported by strong statutory and regulatory history and was originally approved by Congress in 1977. In a June 2012 lawsuit (*Sierra Club v. Bostick*), to which we were not a party, a plaintiff sought to have the court strike down the NWP and enjoin the construction of a particular oil pipeline project that would run from Cushing, Oklahoma to oil refineries along the Gulf Coast near Port Arthur, Texas. In August 2012, a District Court denied the motion to enjoin the construction and ruled that the Corps had acted properly in approving the project under the NWP. The District Court s decision was reaffirmed by the Tenth Circuit Court of Appeals in October 2013. We cannot predict whether future lawsuits will be filed to contest the validity of the NWP; however, in the event that a court wholly or partially strikes down the NWP, which we believe to be unlikely, we could face significant delays and financial costs when seeking project approvals.

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.

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General Interstate Regulation. Our interstate common carrier liquids pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act (ICA). The ICA requires that tariff rates for liquids pipelines, which include both crude oil pipelines and refined products pipelines, be just and reasonable and non-discriminatory.

State Regulation. Our intrastate liquids pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies, including the Railroad Commission of Texas (TRRC) and the California Public Utility Commission (CPUC). The CPUC prohibits certain of our subsidiaries from acting as guarantors of our senior notes and credit facilities.

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 (now replaced by the Bureau of Ocean Energy Management, Regulation and Enforcement) issued a final rule establishing formal and informal complaint procedures for shippers that believe they have been denied open and nondiscriminatory access to transportation on the OCS. We do not expect the rule to have a material impact on our operations or results.

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992 (EPAct), which, among other things, required the FERC to issue rules to establish a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by establishing a formulaic methodology for petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC reviews the formula every five years. Effective July 1, 2011, the annual index adjustment for the five year period ending June 30, 2016 will equal the producer price index for finished goods for the applicable year plus an adjustment factor of 2.65%. Pipelines may raise their rates to the rate ceiling level generated by application of the annual index adjustment factor each year; however, a shipper may challenge such increase if the increase in the pipeline s rates was substantially in excess of the actual cost increases incurred by the pipeline during the relevant year. If the FERC s annual index adjustment 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 the 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 and settlement rates as alternatives to the indexing approach that may be used in certain specified circumstances. Because the indexing methodology for the next five-year period 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 such 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.

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial authorities, such as the AER. 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.

Our Pipelines. The FERC generally has not investigated rates of liquids pipelines on its own initiative when those rates have not been the subject of a protest or complaint by a shipper. The majority of our transportation segment profit in the United States is produced by rates that are either grandfathered or set by agreement with one or more shippers.

Trucking Regulation

United States

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: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailer vehicles, (v) drug and alcohol testing, (vi) operation and equipment safety and (vii) many other aspects of truck operations. We are also subject to OSHA with respect to our trucking operations.

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Canada

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. We are licensed to operate both intra- and inter-provincially under the direction of the National Safety Code (NSC) that is administered by Transport Canada. Our for-hire service is primarily the transportation of crude oil, condensates and NGL. We are required under the NSC among other things to monitor: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailers, (v) operation and equipment safety and (vi) many other aspects of trucking operations. We are also subject to Occupational Health and Safety regulations with respect to our trucking operations. We believe that our trucking operations are in substantial compliance with all existing federal, state and local regulations.

Railcar Regulation

We operate a number of railcar loading and unloading facilities, and lease a significant number of railcars, in the United States and Canada. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, the Occupational Safety and Health Administration, as well as other federal and state regulatory agencies and Canadian regulatory agencies for operations in Canada. We believe that our railcar operations are in substantial compliance with all existing federal, state, and local regulations.

Recent railcar accidents in Lac-Megantic, Quebec, Aliceville, Alabama and Casselton, North Dakota involving derailments and explosions have led to increased regulatory scrutiny over the safety of transporting crude oil by rail. All of these incidents involved trains carrying crude oil from North Dakota s Bakken shale formation. In the wake of the Casselton derailment, PHMSA issued a safety advisory warning that Bakken crude may be more flammable than other grades of crude oil and reinforcing the requirement to properly test, characterize, classify, and where appropriate sufficiently degasify hazardous materials prior to and during transportation. PHMSA also initiated Operation Classification , a compliance initiative involving unannounced inspections and testing of crude oil samples to verify that offerors of the materials have properly classified, described and labeled the hazardous materials before transportation. On February 25, 2014, the DOT issued an emergency order designed to insure that crude oil is properly tested and classified prior to transportation by rail in accordance with existing hazardous materials regulations. The DOT emergency order also provides for potential penalties for non-compliance of up to $175,000 per violation. While we believe that we are in material compliance with existing regulations governing our railcar operations, the extent to which the DOT s emergency order requires additional procedures has not yet been fully established; accordingly, we cannot predict the impact that the DOT order and any future regulations may have on our operations.

These recent accidents could also prompt lawmakers to step up their efforts to phase out or require upgrades on the DOT Class 111 tank railcar, the most commonly used tank car to transport crude oil by railcar in North America. A DOT Class 111 rail tanker is not pressurized, unlike sturdier DOT-112 and -114 models used to transport more volatile liquids such as propane and methane. The U.S. National Transportation Safety Board has recommended that all tank cars used to carry crude oil be reinforced to make them more resistant to punctures if trains derail. This recommendation has not yet been adopted by PHMSA. PHMSA has said that it is considering amendments to current regulations that would enhance rail safety, including for DOT-111 railcars, but the rules are still under development. Any requirement to retrofit and upgrade existing rail tankers (DOT-111 or other models) could involve substantial cost to the partnership and we can provide no assurance that such a future compliance obligation will not have a material adverse impact on our financial condition or results of operations.

Cross Border Regulation

As a result of our cross border activities, including importation of crude oil, NGL and natural gas 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. In addition, the importation and exportation of natural gas from and to the United States and Canada is subject to regulation by U.S. Customs and Border Protection, U.S. Department of Energy and the NEB. 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. federal, state and local tax requirements, as well as Canadian federal and provincial tax requirements, could lead to the imposition of additional taxes, interest and penalties.

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Market Anti-Manipulation Regulation

In November 2009, the Federal Trade Commission (FTC) issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (CFTC) to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In November 2010, the CFTC issued proposed rules to implement their new anti-manipulation authority. The proposed rules would subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation.

We have not experienced a material impact from the FTC regulations. The CFTC rules are not final. We will continue to monitor the status of proposed rules.

Natural Gas Storage Regulation

Our natural gas storage operations are subject to regulatory oversight by numerous federal, state and local regulatory agencies, many of which are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas storage and pipeline industry, related businesses and market participants. The failure to comply with such laws and regulations can result in substantial penalties and fines. The regulatory burden increases our cost of doing business and, consequently, affects our profitability. 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. We do not believe that we are affected by applicable laws and regulations in a significantly different manner than are our competitors.

The following is a summary of the kinds of regulation that may impact our natural gas storage operations. However, our shareholders should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our natural gas storage operations.

Our natural gas storage facilities provide natural gas storage services in interstate commerce and are subject to comprehensive regulation by the FERC under the Natural Gas Act of 1938 (NGA). Pursuant to the NGA and FERC regulations, storage providers are prohibited from making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage or from maintaining any unreasonable difference in rates, charges, service, facilities, or in any other respect. The terms and conditions for services provided by our facilities are set forth in FERC approved tariffs. We have been granted market-based rate authorization for the services that our facilities provide. Market-based rate authority allows us to negotiate rates with individual customers based on market demand.

The FERC also has authority over the siting, construction, and operation of United States pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale for resale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. The FERC s authority extends to maintenance of accounts and records, terms and conditions of service, 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. Our natural gas storage entities are required by the FERC to post certain information daily regarding customer activity, capacity and volumes on their respective websites.

Additionally, the FERC has jurisdiction to impose rules and regulations applicable to all natural gas market participants to ensure market transparency. FERC regulations require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC. Our natural gas storage facilities and related marketing entities are subject to these annual reporting requirements.

Under the Energy Policy Act of 2005 (EPAct 2005) and related regulations, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to FERC jurisdiction to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 gives the FERC civil penalty authority to impose penalties for certain violations of up to $1 million per day for each violation. FERC also has the authority to order disgorgement of profits from transactions deemed to violate the NGA and the EPAct 2005.

The natural gas industry historically has been heavily regulated. New rules, orders, regulations or laws may be passed or implemented that impose additional costs, burdens or restrictions on us. We cannot give any assurance regarding the likelihood of such future rules, orders, regulations or laws or the effect they could have on our business, financial condition, and results of operations or ability to make distributions to our shareholders.

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 30 times since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. The overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. As a result, we have elected to self-insure more activities against certain of these operating hazards and expect this trend will continue in the future. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies. We have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets, including our nation s pipeline infrastructure, may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, there can be no assurance 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

Our real property holdings are generally comprised of: (i) parcels of land that we own in fee, (ii) surface leases, underground storage leases and (iii) easements, rights-of-way, permits, crossing agreements or licenses from landowners or governmental authorities permitting the use of certain lands for our operations. We believe we have satisfactory title or the right to use the sites upon which our significant facilities are located, subject to customary liens, restrictions or encumbrances. We have no knowledge of any challenge to the underlying fee title of any material fee, lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material deed, lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses. Some of our real property rights (mainly for pipelines) may be subject to termination under agreements that provide for one or more of: periodic payments, term periods, renewal rights, revocation by the licensor or grantor and possible relocation obligations. We believe that our real property holdings are adequate for the conduct of our business activities and that none of the burdens discussed above will materially (i) detract from the value of such properties or (ii) interfere with the use of such properties in our business.

Employees and Labor Relations

Through GP LLC or its affiliates, we employed approximately 4,900 employees at December 31, 2013. None of the employees are subject to a collective bargaining agreement, except for eight employees covered by an agreement scheduled for renegotiation in September 2015 and another nine employees covered by another agreement scheduled for renegotiation in September 2016. We consider employee relations to be good.

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Summary of Tax Considerations

The following is a summary of material U.S. federal income tax consequences, tax considerations, and in the case of a non-U.S. holder, estate tax consequences related to the purchase, ownership and disposition of our Class A shares by a taxpayer that holds our Class A shares as a capital asset (generally property held for investment). This summary is based on the provisions of the Internal Revenue Code of 1986, as amended (the Code), U.S. Treasury regulations and administrative rulings and judicial decisions, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect. We have not sought any ruling from the Internal Revenue Service, or the IRS, with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS will agree with such statements and conclusions.

This summary does not address all aspects of U.S. federal income and estate taxation or the tax considerations arising under the laws of any non-U.S., state, or local jurisdiction, or under U.S. federal gift tax laws. In addition, this summary does not address tax considerations applicable to investors that may be subject to special treatment under the U.S. federal income tax laws. The tax consequences of ownership of Class A shares depends in part on the owner s individual tax circumstances. It is the responsibility of each shareholder, 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, as well as Canada and the Canadian provinces, of the shareholder s investment in us. Further, it is the responsibility of each shareholder to file all U.S. federal, Canadian, state, provincial and local tax returns that may be required of the shareholder. Also see Item 1A. Risk Factors Tax Risks.

Corporate Status

Although we are a Delaware limited partnership, we have elected to be treated as a corporation for U.S. federal income tax purposes. As a result, we are subject to tax as a corporation and distributions on the Class A shares will be treated as distributions on corporate stock for federal income tax purposes. No Schedule K-1s will be issued with respect to the Class A shares, but instead holders of Class A shares will receive a Form 1099 from us with respect to distributions received on the Class A shares.

Consequences to U.S. Holders

The discussion in this section is addressed to holders of our Class A shares who are U.S. holders for U.S. federal income tax purposes. A U.S. holder for purposes of this discussion is a beneficial owner of our Class A shares and who is, for U.S. federal income tax purposes:

- an individual citizen or resident of the United States;

- a corporation, or other entity taxable as a corporation for U.S. federal income tax purposes, that was created or organized in or under the laws of the United States, any state thereof or the District of Columbia;

- an estate whose income is subject to U.S. federal income tax regardless of its source; or

- a trust if (i) a U.S. court can exercise primary supervision over the trust s administration and one or more United States persons are authorized to control all substantial decisions of the trust or (ii) certain circumstances apply and the trust has validly elected to be treated as a United States person.

Distributions

Distributions with respect to our Class A shares will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent that the amount of a distribution with respect to our Class A shares exceeds our current and accumulated earnings and profits, such distribution will be treated first as a tax-free return of capital to the extent of the U.S. holder s adjusted tax basis in such Class A shares, which reduces such basis dollar-for-dollar, and thereafter as capital gain. Such gain will be long-term capital gain provided that the U.S. holder has held such Class A shares for more than one year as of the time of the distribution. Non-corporate holders that receive distributions on our Class A shares that are treated as dividends for U.S. federal income tax purposes generally would be subject to U.S. federal income tax at a maximum tax rate of 20% on such dividends provided certain holding period requirements are met.

Both AAP and PAA have made elections permitted by Section 754 of the Code. As a result, our initial acquisition of interests in AAP resulted in basis adjustments with respect to our interest in the assets of AAP (and indirectly in PAA). Such adjustments resulted in depreciation and amortization deductions that we anticipate will offset a substantial portion of our taxable income for an extended period of time. In addition, future exchanges of retained interests in AAP and Class B shares in us for our

Class A shares will result in additional basis adjustments with respect to our interest in the assets of AAP (and indirectly in PAA). We expect to benefit from additional tax deductions resulting from those adjustments, the amount of which will vary depending on the value of the Class A shares at the time of the exchange.

We do not expect to have any earnings and profits for an extended period of time, which we estimate will include, at a minimum, each of the periods ending December 31, 2014, 2015, and 2016, and we may not have sufficient earnings and profits during future tax years for any distributions on our Class A shares to qualify as dividends for U.S. federal income tax purposes. If a distribution on our Class A shares fails to qualify as a dividend for U.S. federal income tax purposes, U.S. corporate holders would be unable to utilize the corporate dividends-received deduction.

Prospective investors in our Class A shares are encouraged to consult their tax advisors as to the tax consequences of receiving distributions on our Class A shares that do not qualify as dividends for U.S. federal income tax purposes, including, in the case of prospective corporate investors, the inability to claim the corporate dividends received deduction with respect to such distributions.

Gain on Disposition of Class A Shares

A U.S. holder generally will recognize capital gain or loss on a sale, exchange, certain redemptions, or other taxable disposition of our Class A shares equal to the difference, if any, between the amount realized upon the disposition of such Class A shares and the U.S. holder s adjusted tax basis in those shares. A U.S. holder s tax basis in the shares generally will be equal to the amount paid for such shares reduced (but not below zero) by distributions received on such shares that are not treated as dividends for U.S. federal income tax purposes. Such capital gain or loss generally will be long-term capital gain or loss if the U.S. holder s holding period for the shares sold or disposed of is more than one year. Long-term capital gains of individuals generally are subject to a reduced maximum U.S. federal income tax rate of 20%. The deductibility of net capital losses is subject to limitations.

Backup Withholding and Information Reporting

Information returns generally will be filed with the IRS with respect to distributions on our Class A shares and the proceeds from a disposition of our Class A shares. U.S. holders may be subject to backup withholding on distributions with respect to our Class A shares and on the proceeds of a disposition of our Class A shares unless such U.S. holders furnish the applicable withholding agent with a taxpayer identification number, certified under penalties of perjury, and certain other information, or otherwise establish, in the manner prescribed by law, an exemption from backup withholding. Penalties apply for failure to furnish correct information and for failure to include reportable payments in income.

Backup withholding is not an additional tax. Any amounts withheld under the backup withholding rules will be creditable against a U.S. holder s U.S. federal income tax liability, and the U.S. holder may be entitled to a refund, provided the U.S. holder timely furnishes the required information to the IRS. U.S. holders are urged to consult their own tax advisors regarding the application of the backup withholding rules to their particular circumstances and the availability of, and procedure for, obtaining an exemption from backup withholding.

Consequences to Non-U.S. Holders

The discussion in this section is addressed to holders of our Class A shares who are non-U.S. holders for U.S. federal income tax purposes. For purposes of this discussion, a non-U.S. holder is a beneficial owner of our Class A shares that is an individual, corporation, estate or trust that is not a U.S. holder as defined above.

Distributions

Generally, a distribution treated as a dividend paid to a non-U.S. holder on our Class A shares will be subject to U.S. withholding tax at a rate of 30% of the gross amount of the distribution, or such lower rate as may be specified by an applicable income tax treaty. To the extent a distribution exceeds our current and accumulated earnings and profits, such distribution will reduce the non-U.S. holder s adjusted tax basis in its Class A shares (but not below zero). The amount of any such distribution in excess of the non-U.S. holder s adjusted tax basis in its Class A shares will be treated as gain from the sale of such shares and will have the tax consequences described below under Gain on Disposition of Class A Shares. The rules applicable to distributions by USRPHCs (as defined below) to non-U.S. persons that exceed current and accumulated earnings and profits are not clear. As a result, it is possible that U.S. federal income tax at a rate not less than 10% (or such lower rate as may be specified by an applicable income tax treaty for distributions from a USRPHC) may be withheld from distributions received by non-U.S. holders that exceed our current and accumulated earnings and profits. To receive the benefit of a reduced treaty rate on distributions, a non-U.S. holder must provide the withholding agent with an IRS W-8BEN (or other appropriate form) certifying qualification for the reduced rate.

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Non-U.S. holders are encouraged to consult their tax advisors regarding the withholding rules applicable to distributions on our Class A shares, the requirement for claiming treaty benefits, and any procedures required to obtain a refund of any overwithheld amounts.

Distributions treated as dividends that are paid to a non-U.S. holder and are effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable tax treaty, are attributable to a permanent establishment maintained by the non-U.S. holder in the United States) generally will be taxed on a net income basis at the rates and in the manner generally applicable to U.S. persons (as defined under the Code). Effectively connected dividend income will not be subject to U.S. withholding tax if the non-U.S. holder satisfies certain certification requirements by providing to the withholding agent a properly executed IRS Form W-8ECI (or successor form) certifying eligibility for the exemption. If the non-U.S. holder is a corporation, that portion of the corporation s earnings and profits for the taxable year, as adjusted for certain items, that is effectively connected with its U.S. trade or business (and, if required by applicable income tax treaty, is attributable to a permanent establishment maintained by the corporate non-U.S. holder in the United States) may also be subject to a branch profits tax at a 30% rate or such lower rate as may be specified by an applicable tax treaty.

Gain on Disposition of Class A Shares

A non-U.S. holder generally will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our Class A shares unless:

- the non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met;

- the gain is effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable tax treaty, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States); or

- our Class A shares constitute a U.S. real property interest by reason of our status as a United States real property holding corporation, or USRPHC, for U.S. federal income tax purposes.

A non-U.S. holder described in the first bullet point above will be subject to tax at a rate of 30% (or such lower rate as may be specified by an applicable tax treaty) on the amount of such gain (which may be offset by U.S. source capital losses).

A non-U.S. holder whose gain is described in the second bullet point above will be subject to U.S. federal income tax on any gain recognized on a net income basis at the same graduated rates generally applicable to U.S. persons unless an applicable tax treaty provides otherwise. Corporate non-U.S. holders may also be subject to a branch profits tax equal to 30% (or such lower rate as may be specified by an applicable tax treaty) of their effectively connected earnings and profits attributable to such gain, as adjusted for certain items.

Generally, a corporation is a USRPHC if the fair market value of its U.S. real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We believe that we currently are, and expect to remain for the foreseeable future, a USRPHC for U.S. federal income tax purposes. However, as long as our Class A shares are regularly traded on an established securities market, a non-U.S. holder will be taxable on gain recognized on the disposition of our Class A shares as a result of our status as a USRPHC only if the non-U.S. holder actually or constructively owns, or owned at any time during the five-year period ending on the date of the disposition or, if shorter, the non-U.S. holder s holding period for the Class A shares, more than 5% of our Class A shares. If our Class A shares were not considered to be regularly traded on an established securities market, all non-U.S. holders would be subject to U.S. federal income tax on a disposition of our Class A shares, and a 10% withholding tax would apply to the gross proceeds from the sale of our Class A shares by such non-U.S. holder. Non-U.S. holders should consult their tax advisors with respect to the application of the foregoing rules to their ownership and disposition of our Class A shares.

U.S. Federal Estate Tax

Our Class A shares beneficially owned or treated as owned by an individual who is not a citizen or resident of the United States (as defined for U.S. federal estate tax purposes) at the time of death generally will be includable in the decedent s gross estate for U.S. federal estate tax purposes, unless an applicable estate tax treaty provides otherwise, and therefore may be subject to U.S. federal estate tax.

Backup Withholding and Information Reporting

Generally, we must report annually to the IRS and to each non-U.S. holder the amount of dividends paid to such holder, the name and address of the recipient, and the amount, if any, of tax withheld with respect to those dividends. These information reporting requirements apply even if withholding was not required. Pursuant to tax treaties or other agreements, the IRS may make such reports available to tax authorities in the recipient s country of residence.

Payments of dividends to a non-U.S. holder generally will not be subject to backup withholding if the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8, provided that the withholding agent does not have actual knowledge, or reason to know, that the beneficial owner is a U.S. person that is not an exempt recipient.

Payments of the proceeds from a sale or other disposition by a non-U.S. holder of our Class A shares effected by or through a U.S. office of a broker generally will be subject to information reporting and backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8 and certain other conditions are met or the non-U.S. holder otherwise establishes an exemption. Information reporting and backup withholding generally will not apply to any payment of the proceeds from a sale or other disposition of our Class A shares effected outside the United States by a foreign office of a broker. However, unless such broker has documentary evidence in its records that the holder is a non-U.S. holder and certain other conditions are met, or the non-U.S. holder otherwise establishes an exemption, information reporting will apply to a payment of the proceeds of the disposition of our Class A shares effected outside the United States by such a broker if it has certain relationships within the United States.

Backup withholding is not an additional tax. Rather, the U.S. income tax liability (if any) of persons subject to backup withholding will be reduced by the amount of tax withheld. If withholding results in an overpayment of taxes, a refund may be obtained, provided that certain required information is timely furnished to the IRS.

Legislation Affecting Class A Shares Held Through Foreign Accounts

Legislation enacted in 2010 imposes a 30% withholding tax on any dividends on our Class A shares and on the gross proceeds from a disposition of our Class A shares in each case if paid to a foreign financial institution or a non-financial foreign entity (including, in some cases, when such foreign financial institution or entity is acting as an intermediary), unless (i) in the case of a foreign financial institution, such institution enters into an agreement with the U.S. government to withhold on certain payments, and to collect and provide to the U.S. tax authorities substantial information regarding U.S. account holders of such institution (which includes certain equity and debt holders of such institution, as well as certain account holders that are foreign entities with U.S. owners), (ii) in the case of a non-financial foreign entity, such entity certifies that it does not have any substantial U.S. owners or provides the withholding agent with a certification identifying the direct and indirect substantial U.S. owners of the entity, or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules. Under certain circumstances, a holder might be eligible for refunds or credits of such taxes.

Payments subject to withholding tax under this law generally include dividends paid on Class A shares after June 30, 2014, and gross proceeds from sales or redemptions of such Class A shares after December 31, 2016. Non-U.S. holders are encouraged to consult their tax advisors regarding the possible implications of this law.

3.8% Tax on Unearned Income

Certain holders that are individuals, trusts or estates will be subject to an additional 3.8% Medicare tax on unearned income, which generally will include dividends received and gain recognized with respect to our Class A shares. For individual U.S. holders, the additional Medicare tax applies to the lesser of (i) net investment income, or (ii) the excess of modified adjusted gross income over $200,000 ($250,000 if married and filing jointly or $125,000 if married and filing separately). Net investment income generally equals a holder s gross investment income reduced by the deductions that are allocable to such income. Investment income generally includes passive income such as interest, dividends, annuities, royalties, rents and capital gains. Holders are urged to consult their own tax advisors regarding the application of this additional Medicare tax to their particular circumstances.

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Available Information

We make available, free of charge on our Internet website at ir.paagp.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 (SEC).

Item 1A. ***Risk Factors***

Risks Inherent in an Investment in Us

Our cash flow will be entirely dependent upon the ability of PAA to make cash distributions to AAP, and the ability of AAP to make cash distributions to us.

The source of our earnings and cash flow currently consist exclusively of cash distributions from AAP, which currently consist exclusively of cash distributions from PAA. The amount of cash that PAA will be able to distribute to its partners, including AAP, each quarter principally depends upon the amount of cash it generates from its business. For a description of certain factors that can cause fluctuations in the amount of cash that PAA generates from its business, please read Risks Related to PAA s Business and Management s Discussion and Analysis of Financial Condition and Results of Operations. PAA may not have sufficient available cash each quarter to continue paying distributions at its current level or at all. If PAA reduces its per unit distribution, either because of reduced operating cash flow, higher expenses, capital requirements or otherwise, we will have less cash available for distribution and would likely be required to reduce our per share distribution. The amount of cash PAA has available for distribution depends primarily upon PAA s cash flow, including cash flow from the release of financial reserves as well as borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, PAA may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records profits.

Furthermore, AAP s ability to distribute cash to us and our ability to distribute cash received from AAP to our Class A shareholders is limited by a number of factors, including:

- AAP s payment of costs and expenses associated with our operations, and the operations of GP LLC, including expenses we incur as a result of being a public company, to the extent they are not subject to reimbursement by PAA;
- our payment of any income taxes;
- interest expense and principal payments on any indebtedness incurred by AAP or us;

- restrictions on distributions contained in AAP s and PAA s respective credit facilities and any future debt agreements entered into by AAP, PAA or us;

- reserves necessary for us to pay a ratable amount to AAP as necessary to permit AAP to make required capital contributions to PAA to maintain AAP s indirect 2% general partner interest in PAA, as required by the partnership agreement of PAA upon the issuance of additional partnership interests by PAA; and

- reserves our general partner establishes for the proper conduct of our business, to comply with applicable law or any agreement binding on us or our subsidiaries (exclusive of PAA and its subsidiaries), which reserves are not subject to a limit pursuant to our partnership agreement.

A material increase in amounts paid or reserved with respect to any of these factors could restrict our ability to pay quarterly distributions to our Class A shareholders.

The IDRs AAP is entitled to receive may be limited or modified without the consent of our shareholders, which may reduce cash distributions to our Class A shareholders.

At December 31, 2013, we owned a 22.1% limited partner interest in AAP, which owns all of PAA s IDRs, which entitle AAP to receive increasing percentages (up to a maximum of 48%, to the extent not modified) of any cash distributed by PAA in excess of $0.225 per PAA common unit in any quarter. The vast majority of the cash flow we receive from AAP is derived from its ownership of these IDRs.

PAA, like other publicly traded partnerships, will generally only undertake an acquisition or expansion capital project if, after giving effect to related costs and expenses, the transaction would be expected to be accretive, meaning it would increase cash distributions per unit in future periods. Because AAP currently participates in the IDRs at all levels, including the highest sharing level of 48%, to the extent not modified, it is harder for an acquisition or capital project to show accretion for the common unitholders of PAA than if the IDRs received less incremental cash flow. We therefore expect that AAP may determine, in certain cases, to propose a reduction to the IDRs to facilitate a particular acquisition or expansion capital project. Any such reduction of IDRs will reduce the amount of cash that would have otherwise been distributed by AAP to us, which will in turn reduce the cash distributions we would otherwise be able to pay to our Class A shareholders. Our shareholders will not be able to vote on, or otherwise prohibit our general partner from taking, similar actions in the future and our general partner may elect to modify the IDRs without considering the interests of the holders of the Class A shares. In addition, there can be no guarantee that the expected benefits of any IDR modification will be realized.

A reduction in PAA s distributions below certain levels will lead to a disproportionately greater reduction in the amount of cash distributions to which AAP is currently entitled.

AAP s ownership of PAA s IDRs entitle it to receive increasing percentages, ranging from 13% up to 48%, to the extent not modified, of all cash distributed by PAA in excess of $0.225 per PAA common unit per quarter. A decrease in the amount of distributions paid by PAA to less than $0.3375 per PAA common unit per quarter would reduce AAP s percentage of incremental cash distributions in excess of $0.225 per PAA common unit per quarter from 48% to as low as 13%. As a result, any such reduction in quarterly cash distributions from PAA would have the effect of disproportionately reducing the amount of distributions that AAP receives from PAA in respect of the IDRs as compared to cash distributions PAA makes with respect to its 2% general partner interest and common units.

If distributions on our Class A shares are not paid with respect to any fiscal quarter, our Class A shareholders will not be entitled to receive that quarter s payments in the future.

Our distributions to our Class A shareholders are not cumulative. Consequently, if distributions on our Class A shares are not paid with respect to any fiscal quarter, our Class A shareholders will not be entitled to receive that quarter s payments in the future.

The amount of cash that we and PAA distribute each quarter may limit our ability to grow.

Because we distribute all of our available cash, our growth may not be as fast as the growth of businesses that reinvest their available cash to expand ongoing operations. In fact, because currently our cash flow is generated solely from distributions we receive from AAP, which are derived from AAP s direct and indirect partnership interests in PAA, our growth will initially be completely dependent upon PAA. The amount of distributions received by AAP is based on PAA s per unit distribution paid on each PAA common unit and the number of PAA common units outstanding. If we issue additional Class A shares or we were to incur debt or are required to pay taxes, the payment of distributions on those additional Class A shares, or interest on such debt or payment of such taxes could increase the risk that we will be unable to maintain or increase our cash distribution levels.

Our rate of growth may be reduced to the extent we purchase equity interests from PAA, which will reduce the relative percentage of the cash we receive from the IDRs.

Our business strategy includes, where appropriate, supporting the growth of PAA by making loans, purchasing equity interests or providing other forms of financial support to PAA to provide funding for the acquisition of a business or asset or for an internal growth project. To the extent we purchase equity interests from PAA that are not entitled to distributions or do not receive distributions at the same rates as the IDRs, the rate of our distribution growth may be reduced, at least in the short term, as less of our cash distributions will come from our ownership of IDRs, with respect to which distributions increase at a faster rate than PAA s common units and any similar equity interests PAA may issue in the future.

Restrictions in AAP s and PAA s respective credit facilities could limit AAP s ability to make distributions to us, thereby limiting our ability to make distributions to our Class A shareholders.

AAP s and PAA s respective credit facilities contain various operating and financial restrictions and covenants. AAP s and PAA s respective ability to comply with these restrictions and covenants may be affected by events beyond their control, including prevailing economic, financial and industry conditions. If AAP or PAA is unable to comply with these restrictions and covenants, any indebtedness under these credit facilities may become immediately due and payable and AAP s and PAA s respective lenders commitment to make further loans under these credit facilities may terminate. AAP or PAA might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, AAP s credit facility limits our ability to pay distributions to our Class A shareholders during an event of default or if an event of default would result from the distribution.

For more information regarding AAP s and PAA s credit facilities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources. For information regarding risks related to PAA s credit facilities, please see Risks Related to PAA s Business The terms of PAA s indebtedness may limit its ability to borrow additional funds or capitalize on business opportunities. In addition, PAA s future debt level may limit its future financial and operating flexibility.

Substantially all of AAP s assets, including the IDRs and its indirect 2% general partner interest in PAA, are pledged under AAP s credit facility.

Substantially all of AAP s assets, including the IDRs and its indirect 2% general partner interest in PAA, are pledged as security under AAP s credit facility. AAP s credit facility contains customary and other events of default. Upon an event of default, the lenders under AAP s credit facility could foreclose on AAP s assets, including the IDRs and its indirect 2% general partner interest in PAA, which are the only assets from which our cash flows are derived. This would have a material adverse effect on our business, financial condition and results of operations.

Our shareholders do not elect or have the power to remove our general partner and until certain conditions are met will not vote in the election of our general partner s directors. The Class B shareholders own a sufficient number of shares to allow them to prevent the removal of our general partner.

Our shareholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. The board of directors of our general partner, including our independent directors, have been designated and elected by the Legacy Owners or their designees. Our shareholders do not currently have the ability to elect our general partner or the members of the board of directors of our general partner. However, when the overall direct and indirect economic interest of the Legacy Owners and their permitted transferees in AAP falls below 40% (calculated as described below), subject to certain time and other limitations, which we refer to as a trigger date, our shareholders will have the right to elect certain of our general partner s directors. The 40% threshold referred to above will be calculated on a fully diluted basis that takes into account any Class A shares owned by the Legacy Owners and their affiliates and permitted transferees, assumes the exchange of all AAP Management Units for AAP units based on the applicable conversion factor and attributes the ownership of such AAP units to the Legacy Owners. However, as a result of our resulting governance arrangements, including a staggered board of directors, limitations on director nomination rights and the 20% voting limitation in our partnership agreement, it will be difficult for one or more of our shareholders to gain control of our general partner s board of directors. Moreover, a period of up to three years, in certain circumstances, may lapse between the occurrence of a trigger date and the first meeting of shareholders called to elect members of our board of directors.

In addition, if our Class A shareholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. Our general partner may only be removed by vote of the holders of at least 66 2/3% of our outstanding shares (including both Class A and Class B shares). At December 31, 2013, the Legacy Owners owned 77.9% of our outstanding shares. This ownership level enables the Legacy Owners to prevent our general partner s removal.

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

Our general partner may cause us to issue additional Class A shares or other equity securities, including equity securities that are senior to our Class A shares, or cause AAP to issue additional securities, in each case without shareholder approval, which may adversely affect our shareholders.

Our general partner may cause us to issue an unlimited number of additional Class A shares or other equity securities of equal rank with the Class A shares, or cause AAP to issue additional securities, in each case without shareholder approval. In addition,

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we may issue an unlimited number of shares that are senior to our Class A shares in right of distribution, liquidation and voting. Except for Class A shares issued in connection with the exercise of an Exchange Right, which will result in the cancellation of an equivalent number of Class B shares and therefore have no effect on the total number of outstanding shares, the issuance of additional Class A shares or our other equity securities of equal or senior rank, or the issuance by AAP of additional securities, will have the following effects:

- each shareholder s proportionate ownership interest in us may decrease;
- the amount of cash available for distribution on each Class A share may decrease;
- the relative voting strength of each previously outstanding Class A share may be diminished;
- the ratio of taxable income to distributions may increase; and
- the market price of the Class A shares may decline.

If PAA s unitholders remove PAA GP, AAP may be required to sell or exchange its indirect general partner interest and its IDRs and we would lose the ability to manage and control PAA.

We currently manage our investment in PAA through our membership interest in GP LLC, the general partner of AAP. PAA s partnership agreement, however, gives unitholders of PAA the right to remove PAA GP upon the affirmative vote of holders of 66 2/3% of PAA s outstanding units. If PAA GP withdraws as general partner in compliance with PAA s partnership agreement or is removed as general partner of PAA where cause (as defined in PAA s partnership agreement) does not exist and a successor general partner is elected in accordance with PAA s partnership agreement, AAP could elect to receive cash in exchange for its 2% general partner interest and the IDRs (if then owned by AAP). If PAA GP withdraws in circumstances other than those described in the preceding sentence and a successor general partner is elected in accordance with PAA s partnership agreement, the successor general partner will have the option to purchase the 2% general partner interest and the IDRs (if then owned by AAP) for their fair market value. If PAA GP or the successor general partner do not exercise their options, PAA GP s interests would be converted into common units based on an independent valuation. In each case, PAA GP would also lose its ability to manage PAA.

In addition, if PAA GP is removed as general partner of PAA, we would face an increased risk of being deemed an investment company. Please read If in the future we cease to manage and control PAA, we may be deemed to be an investment company under the Investment Company Act of 1940.

Shareholders may not have limited liability if a court finds that shareholder action constitutes control of our business.

Under Delaware law, our shareholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our shareholders as a group to remove or replace our general partner, to approve some amendments to the partnership agreement or to take other action under our partnership agreement constituted participation in the control of our business. Additionally, the limitations on the liability of holders of limited partner interests for the liabilities of a limited partnership have not been clearly established in many jurisdictions.

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

If in the future we cease to manage and control PAA, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to indirectly manage and control PAA and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act of 1940, obtain exemptive relief from the SEC or modify our organizational structure or our contractual rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict the ability of PAA and us to borrow funds or engage in other transactions involving leverage, require us to add additional directors who are independent of us and our affiliates, and adversely affect the price of our Class A shares.

Our partnership agreement restricts the rights of shareholders owning 20% or more of our shares.

Our shareholders voting rights are restricted by the provision in our partnership agreement generally providing that any shares held by a person or group that owns 20% or more of any class of shares then outstanding, other than our general partner, the Legacy Owners (or certain transferees in private, non-exchange transactions), their respective affiliates and persons who acquired such shares with the prior approval of our general partner s board of directors, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our shareholders to call meetings or to acquire information about our operations, as well as other provisions limiting our shareholders ability to influence the manner or direction of our management. As a result, the price at which our Class A shares will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

If PAA s general partner, which is owned by AAP, is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of PAA, its value, and, therefore, the value of our Class A shares, could decline.

AAP, GP LLC and their affiliates may make expenditures on behalf of PAA for which PAA GP will seek reimbursement from PAA. Under Delaware partnership law, PAA GP has unlimited liability for the obligations of PAA, such as its debts and environmental liabilities, except for those contractual obligations of PAA that are expressly made without recourse to the general partner. To the extent PAA GP incurs obligations on behalf of PAA, it is entitled to be reimbursed or indemnified by PAA. If PAA is unable or unwilling to reimburse or indemnify PAA GP, PAA GP may be required to satisfy those liabilities or obligations, which would reduce AAP s cash flows to us.

The price of our Class A shares may be volatile, and holders of our Class A shares could lose a significant portion of their investments.

The market price of our Class A shares could be volatile, and our shareholders may not be able to resell their Class A shares at or above the price at which they purchased such Class A shares due to fluctuations in the market price of the Class A shares, including changes in price caused by factors unrelated to our operating performance or prospects or the operating performance or prospects of PAA. The following factors, among others, could affect our Class A share price:

- PAA s operating and financial performance and prospects and the trading price of its common units;
- the level of PAA s quarterly distributions and our quarterly distributions;
- quarterly variations in the rate of growth of our financial indicators, such as distributable cash flow per Class A share, net income and revenues;
- changes in revenue or earnings and distribution estimates or publication of research reports by analysts;

- speculation by the press or investment community;
- sales of our Class A shares by our shareholders;
- the exercise by the Legacy Owners of their exchange rights with respect to any retained AAP units;
- announcements by PAA or its competitors of significant contracts, acquisitions, strategic partnerships, joint ventures, securities offerings or capital commitments;
- general market conditions, including conditions in financial markets;
- changes in accounting standards, policies, guidance, interpretations or principles;
- adverse changes in tax laws or regulations;
- domestic and international economic, legal and regulatory factors related to PAA s performance; and
- other factors described in these Risk Factors.

An increase in interest rates may cause the market price of our shares to decline.

Like all equity investments, an investment in our Class A shares is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our Class A shares resulting from investors seeking other more favorable investment opportunities may cause the trading price of our Class A shares to decline.

Future sales of our Class A shares in the public market could reduce our Class A share price, and any additional capital raised by us through the sale of equity or convertible securities may have a dilutive effect on our shareholders.

Subject to certain limitations and exceptions, holders of AAP units may exchange their AAP units (together with a corresponding number of Class B shares) for Class A shares (on a one-for-one basis, subject to customary conversion rate adjustments for equity splits and reclassification and other similar transactions) and then sell those Class A shares. We may also issue additional Class A shares or convertible securities in subsequent public or private offerings.

We cannot predict the size of future issuances of our Class A shares or securities convertible into Class A shares or the effect, if any, that future issuances and sales of our Class A shares will have on the market price of our Class A shares. Sales of substantial amounts of our Class A shares (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Class A shares.

The Legacy Owners hold a majority of the combined voting power of our Class A and Class B shares.

At December 31, 2013, the Legacy Owners held approximately 77.9% of the combined voting power of our Class A and Class B shares. The Legacy Owners are entitled to act separately in their own respective interests with respect to their partnership interests in us, and collectively they currently have the ability to (i) determine the outcome of all matters requiring shareholder approval, including certain mergers and other material transactions and (ii) cause or prevent a change in the composition of our board of directors or a change in control of our company that could deprive our shareholders of an opportunity to receive a premium for their Class A shares as part of a sale of our company. So long as the Legacy Owners continue to own a significant amount of our outstanding shares, even if such amount is less than 50%, they will continue to be able to strongly influence all matters requiring shareholder approval, regardless of whether or not other shareholders believe that such matters are in their own best interests.

If we or PAA fail to maintain an effective system of internal controls, our ability to accurately report our financial results or prevent fraud could be adversely affected. As a result, our shareholders could lose confidence in our financial reporting, which would harm our business and the trading price of our Class A shares.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a publicly traded partnership. We are required to comply with the SEC s rules implementing Sections 302 and 404 of the Sarbanes-Oxley Act of 2002, which require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Though we are required to disclose material changes made to our internal controls and procedures on a quarterly basis, we are not required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 until the year following the filing of this annual report with the SEC. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results will be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our Class A shares.

A valuation allowance on our deferred tax asset could reduce our earnings.

A deferred tax asset of approximately $1.1 billion was recorded on our books as a result of certain of the transactions that took place in connection with our initial public offering as well as with subsequent exchanges by Legacy Owners of AAP units and Class B shares into Class A shares. GAAP requires that a valuation allowance must be established for deferred tax assets when it is more likely than not that they will not be realized. We believe that the deferred tax asset we recorded at the time of our initial public offering and the deferred tax assets recorded related to subsequent Legacy Owner exchanges will be realized and that a valuation allowance is not required. However, if we were to determine that a valuation allowance was appropriate for our deferred tax asset, we would be required to take an immediate charge to earnings with a corresponding reduction of partners capital and increase in balance sheet leverage as measured by debt to total capitalization.

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The New York Stock Exchange (NYSE) does not require a limited partnership like us to comply with certain of its corporate governance requirements.

Because we are a limited partnership, the NYSE does not require our general partner to have a majority of independent directors on its board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, our shareholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. In addition, as a limited partnership we are not required to seek shareholder approval for issuances of Class A shares, including issuances in excess of 20% of our outstanding equity securities, or for issuances of equity to certain affiliates.

We may incur liability as a result of our ownership of our and PAA s general partner.

Under Delaware law, a general partner of a limited partnership is generally liable for the debts and liabilities of the partnership for which it serves as general partner, subject to the terms of any indemnification agreements contained in the partnership agreement and except to the extent the partnership s contracts are non-recourse to the general partner. As a result of our structure, we indirectly own and control the general partner of PAA and own a portion of our general partner s membership interests. Our percentage ownership of our general partner is expected to increase over time as the Legacy Owners exercise their exchange rights. To the extent the indemnification provisions in the applicable partnership agreement or non-recourse provisions in our contracts are not sufficient to protect us from such liability, we may in the future incur liabilities as a result of our ownership of these general partner entities.

Risks Related to Conflicts of Interest

Our existing organizational structure and the relationships among us, PAA, our respective general partners, the Legacy Owners and affiliated entities present the potential for conflicts of interest. Moreover, additional conflicts of interest may arise in the future among us and the entities affiliated with any general partner or similar interests we acquire or among PAA and such entities.

Conflicts of interest may arise as a result of our organizational structure and the relationships among us, PAA, our respective general partners, the Legacy Owners and affiliated entities.

Our partnership agreement defines the duties of our general partner (and, by extension, its officers and directors). Our general partner s board of directors or its conflicts committee will have authority on our behalf to resolve any conflict involving us and they have broad latitude to consider the interests of all parties to the conflict.

Conflicts of interest may arise between us and our shareholders, on the one hand, and our general partner and its owners and affiliated entities, on the other hand, or between us and our shareholders, on the one hand, and PAA and its unitholders, on the other hand. The resolution of these conflicts may not always be in our best interest or that of our shareholders.

Our partnership agreement defines our general partner s duties to us and contains provisions that reduce the remedies available to our shareholders for actions that might otherwise be challenged as breaches of fiduciary or other duties under state law.

Our partnership agreement contains provisions that substantially reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, the Legacy Owners, our affiliates or any limited partner. Examples include its right to vote membership interests in our general partner held by us, the exercise of its limited call right, its rights to transfer or vote any shares it may own, and its determination whether or not to consent to any merger or consolidation of our partnership or amendment to our partnership agreement;

- generally provides that our general partner will not have any liability to us or our shareholders for decisions made in its capacity as a general partner so long as it acted in good faith which, pursuant to our partnership agreement, requires a subjective belief that the determination, or other action or anticipated result thereof is in, or not opposed to, our best interests;

- generally provides that any resolution or course of action adopted by our general partner and its affiliates in respect of a conflict of interest will be permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any duty stated or implied by law or equity if the resolution or course of action in respect of such conflict of interest is:

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- approved by a majority of the members of our general partner s conflicts committee after due inquiry, based on a subjective belief that the course of action or determination that is the subject of such approval is fair and reasonable to us;

- approved by majority vote of our Class A shares and Class B shares (excluding shares owned by our general partner and its affiliates, but including shares owned by the Legacy Owners) voting together as a single class;

- determined by our general partner (after due inquiry) to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

- determined by our general partner (after due inquiry) to be fair and reasonable to us, which determination may be made taking into account the circumstances and the relationships among the parties involved (including our short-term or long-term interests and other arrangements or relationships that could be considered favorable or advantageous to us).

- provides that, to the fullest extent permitted by law, in connection with any action or inaction of, or determination made by, our general partner or the conflicts committee of our general partner s board of directors with respect to any matter relating to us, it shall be presumed that our general partner or the conflicts committee of our general partner s board of directors acted in a manner that satisfied the contractual standards set forth in our partnership agreement, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or our partnership challenging any such action or inaction of, or determination made by, our general partner, the person bringing or prosecuting such proceeding shall have the burden of overcoming such presumption; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such person s conduct was criminal.

The Legacy Owners may have interests that conflict with holders of our Class A shares.

At December 31, 2013, the Legacy Owners owned 77.9% of our outstanding shares and 77.9% of the AAP units. As a result, the Legacy Owners may have conflicting interests with holders of Class A shares. For example, the Legacy Owners may have different tax positions from us which could influence their decisions regarding whether and when to cause us to dispose of assets.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and the Legacy Owners, on the other hand, concerning among other things, a decision whether to modify or limit the IDRs in the future or potential competitive business activities or business opportunities. These conflicts of interest may not be resolved in our favor.

If we are presented with business opportunities, PAA has the first right to pursue such opportunities.

Pursuant to the administrative agreement, we have agreed to certain business opportunity arrangements to address potential conflicts with respect to business opportunities that may arise among us, our general partner, PAA, PAA GP, AAP and GP LLC. If a business opportunity is presented to us, our general partner, PAA, PAA GP, AAP or GP LLC, then PAA will have the first right to pursue such business opportunity. We have the right to pursue and/or participate in such business opportunity if invited to do so by PAA, or if PAA abandons the business opportunity and GP LLC so notifies our general partner. Accordingly, the terms of the administrative agreement limit our ability to pursue business opportunities.

Our general partner s affiliates and the Legacy Owners may compete with us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. The restrictions contained in our general partner s limited liability company agreement are subject to a number of exceptions. Affiliates of our general partner and the Legacy Owners will not be prohibited from engaging in other businesses or activities that might be in direct competition with us except to the extent they compete using our confidential information.

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Our general partner has a call right that may require our shareholders to sell their Class A shares at an undesirable time or price.

If at any time more than 80% of our outstanding Class A shares and Class B shares on a combined basis (including Class A shares issuable upon the exchange of Class B shares) are owned by our general partner, the Legacy Owners (or certain transferees in private, non-exchange transactions) or their respective affiliates, our general partner will have the right (which it may assign to any of its affiliates, the Legacy Owners or us), but not the obligation, to acquire all, but not less than all, of the remaining Class A shares held by public shareholders at a price equal to the greater of (x) the current market price of such shares as of the date three days before notice of exercise of the call right is first mailed and (y) the highest price paid by our general partner, the Legacy Owners (or certain transferees in private, non-exchange transactions) or their respective affiliates for such shares during the 90 day period preceding the date such notice is first mailed. As a result, holders of our Class A shares may be required to sell such Class A shares at an undesirable time or price and may not receive any return of or on their investment. Class A shareholders may also incur a tax liability upon a sale of their Class A shares. At December 31, 2013, the Legacy Owners owned 77.9% of the Class A shares and Class B shares on a combined basis.

Risks Related to PAA s Business

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

PAA has a number of organic growth projects that involve the construction of new midstream energy infrastructure assets or the expansion or modification of existing assets. Many of these projects involve numerous regulatory, environmental, commercial, economic, weather-related, political and legal uncertainties that are beyond its control, including the following:

- As these projects are undertaken, required approvals, permits and licenses may not be obtained, may be delayed or may be obtained with conditions that materially alter the expected return associated with the underlying projects;

- Despite the fact that PAA will expend significant amounts of capital during the construction phase of these projects, revenues associated with these organic growth projects will not materialize until the projects have been completed and placed into commercial service, and the amount of revenue generated from these projects could be significantly lower than anticipated for a variety of reasons;

- PAA may not be able to secure, or PAA may be significantly delayed in obtaining, all of the rights of way or other real property interests needed to complete such projects, or the costs PAA incurs in order to obtain such rights of way or other interests may be greater than PAA anticipated;

- PAA may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes;

- Due to unavailability or costs of materials, supplies, power, labor or equipment, the cost of completing these projects could turn out to be significantly higher than PAA budgeted and the time it takes to complete construction of these projects and place them into commercial service could be significantly longer than planned; and

- The completion or success of PAA s projects may depend on the completion or success of third-party facilities over which PAA have no control.

As a result of these uncertainties, the anticipated benefits associated with PAA s capital projects may not be achieved. In turn, this could negatively impact PAA s cash flow and its ability to make or increase cash distributions to its partners.

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PAA s 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 its results.

Results from PAA s supply and logistics segment are influenced by the overall forward market for crude oil. A contango market is favorable to commercial strategies that are associated with storage capacity as it allows a party to simultaneously purchase crude oil 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 PAA s 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 in certain circumstances 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, PAA s results from its 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 PAA s results. Depending on the overall duration of these transition periods, how PAA has allocated its assets to particular strategies and the time length of its crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial effect on its 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 PAA s supply and logistics segment.

A natural disaster, catastrophe, terrorist attack or other event, including attacks on PAA s electronic and computer systems, could interrupt its operations and/or result in severe personal injury, property damage and environmental damage, which could have a material adverse effect on its financial position, results of operations and cash flows.

Some of PAA s operations involve risks of personal injury, property damage and environmental damage, which could curtail its operations and otherwise materially adversely affect its cash flow. Virtually all of PAA s operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of PAA s assets and its customers assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk. In addition, 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. Terrorists may target PAA s physical facilities and hackers may attack its electronic and computer systems.

If one or more of PAA s facilities, including electronic and computer systems, or any facilities or businesses that deliver products, supplies or services to PAA or that it relies on in order to operate its business, are damaged by severe weather or any other disaster, accident, catastrophe, terrorist attack or event, its operations could be significantly interrupted. These interruptions could involve significant damage or injury to people, property or the environment, and repairs could take from a week or less for minor incidents to six months or more for major interruptions. Any such event that interrupts the revenues generated by its operations, or which causes PAA to make significant expenditures not covered by insurance, could reduce its cash available for paying distributions to its partners and, accordingly, adversely affect its financial condition and the market price of its securities.

If PAA does not make acquisitions or if it makes acquisitions that fail to perform as anticipated, its future growth may be limited.

PAA s ability to grow its distributions depends in part on its ability to make acquisitions that result in an increase in operating surplus per unit. If PAA is unable to make such accretive acquisitions either because PAA is (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, PAA s future growth will be limited. As a result, PAA may not be able to complete the number or size of acquisitions that it has targeted internally or to continue to grow as quickly as it has historically.

In evaluating acquisitions, PAA generally prepares one or more financial cases based on a number of business, industry, economic, legal, regulatory, and other assumptions applicable to the proposed transaction. Although PAA expects 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 PAA s 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 PAA is able to timely and effectively integrate the underlying assets and such assets perform at or near the levels anticipated in its acquisition projections.

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PAA s acquisition strategy involves risks that may adversely affect its business.

Any acquisition involves potential risks, including:

- performance from the acquired businesses or assets that is below the forecasts PAA used in evaluating the acquisition;
- a significant increase in PAA s 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 for which PAA is not indemnified by a credit-worthy party, including liabilities arising from the operation of the acquired businesses or assets prior to PAA s acquisition;
- risks associated with operating in lines of business that are distinct and separate from PAA s 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 PAA s ability to achieve anticipated levels of cash flows from its acquisitions, realize other anticipated benefits and its ability to pay distributions to its partners or meet its debt service requirements.

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

PAA continuously considers potential acquisitions and opportunities for organic growth projects. Acquisition transactions can be effected quickly, may occur at any time and may be significant in size relative to its existing assets and operations. PAA s ability to fund its capital projects and make acquisitions depends on whether it can access the necessary financing to fund these activities. Any limitations on its access to capital or increase in the cost of that capital could significantly impair its growth strategy. PAA s ability to maintain its targeted credit profile, including maintaining its credit ratings, could affect PAA s cost of capital as well as its ability to execute its growth strategy. In addition, a variety of factors beyond its control could impact the availability or cost of capital, including domestic or international economic conditions, changes in key benchmark interest rates, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets.

Due to these factors, PAA cannot be certain that funding for its capital needs will be available from bank credit arrangements or capital markets on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, PAA may be unable to implement its development plans, enhance its existing business, complete acquisitions and construction projects, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on its revenues and results of operations.

Loss of PAA s investment grade credit rating or the ability to receive open credit could negatively affect its ability to purchase crude oil, NGL and natural gas supplies or to capitalize on market opportunities.

PAA believes that, because of its strategic asset base and complementary business model, PAA will continue to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil, NGL and natural gas markets. The extent to which PAA is able to capture that benefit, however, is subject to numerous risks and uncertainties, including whether PAA will be able to maintain an attractive credit rating and continue to receive open credit from its suppliers and trade counterparties. PAA s senior unsecured debt is currently rated as investment grade by Standard & Poor s and Moody s Investors Service. A downgrade by either of such rating agencies could increase its borrowing costs, reduce its borrowing capacity and cause its counterparties to reduce the amount of open credit it receive from them. This could negatively impact PAA s ability to capitalize on market opportunities. For example, PAA s ability to utilize its crude oil storage capacity for merchant activities to capture contango market opportunities (meaning that the price of crude oil for future deliveries is higher than current prices) is dependent upon having adequate credit facilities, both in terms of the total amount of credit facilities and the cost of such credit facilities, which enables PAA to finance the storage of the crude oil from the time it completes the purchase of the crude oil until the time it completes the sale of the crude oil.

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PAA is exposed to the credit risk of its customers in the ordinary course of its business activities.

Risks of nonpayment and nonperformance by customers are a significant consideration in PAA s business. Although PAA has credit risk management policies and procedures that are designed to mitigate and limit its exposure in this area, there can be no assurance that PAA has adequately assessed and managed the creditworthiness of its existing or future counterparties or that there will not be an unanticipated deterioration in their creditworthiness or unexpected instances of nonpayment or nonperformance, all of which could have an adverse impact on PAA s cash flow and its ability to pay or increase its cash distributions to its partners.

In those cases in which PAA provides division order services for crude oil purchased at the wellhead, it may be responsible for distribution of proceeds to all parties. In other cases, PAA pays all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose PAA to operator credit risk, and there can be no assurance that PAA will not experience losses in dealings with such operators and other parties.

PAA s risk policies cannot eliminate all risks. In addition, any non-compliance with its risk policies could result in significant financial losses.

Generally, it is PAA s policy to establish a margin for crude oil or other products it purchases by selling such products for physical delivery to third-party users, or by entering into a future delivery obligation under derivative contracts. Through these transactions, PAA seeks to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other hand. PAA s policy is not to acquire and hold physical inventory 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 PAA s anticipated physical supply of crude oil or other products could expose it to risk of loss resulting from price changes. PAA is also exposed to basis risk when crude oil or other products are purchased against one pricing index and sold against a different index. Moreover, PAA is exposed to some risks that are not hedged, including risks on certain of its inventory, such as linefill, which must be maintained in order to transport crude oil on its pipelines. In an effort to maintain a balanced position, specifically authorized personnel can purchase or sell an aggregate limit of up to 860,000 barrels of crude oil, refined products and NGL. Although this activity is monitored independently by PAA s risk management function, it exposes PAA to risks within predefined limits and authorizations.

In addition, PAA s operations involve the risk of non-compliance with its risk policies. PAA has taken steps within its organization to implement processes and procedures designed to detect unauthorized trading; however, PAA can provide no assurance that these steps will detect and prevent all violations of its risk policies and procedures, particularly if deception, collusion or other intentional misconduct is involved.

PAA s operations are also subject to laws and regulations relating to protection of the environment and wildlife, operational safety, climate change and related matters that may expose it to significant costs and liabilities.

PAA s operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil, NGL and refined products, as well as PAA s 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. PAA s operations are also subject to laws and regulations relating to protection of the environment and wildlife, operational safety, climate change and related matters. Compliance with all of these laws and regulations increases its overall cost of doing business, including its capital costs to construct, maintain and upgrade equipment and facilities. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases, including cap and trade programs, could require PAA to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. In addition, with respect to our railcar operations, the adoption of new regulations designed to enhance the overall safety of crude oil and natural gas liquids transportation by rail, including new regulations requiring that existing railcars be retrofitted or upgraded to improve integrity, could result in increased operating costs and potentially involve substantial capital expenditures. Also, the failure to comply with any such laws and regulations could result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, the issuance of injunctions that may subject PAA to additional operational requirements and constraints, or claims of damages to property or persons resulting from its operations. The laws and regulations applicable to PAA s operations are subject to change and interpretation by the relevant governmental agency, including the possibility that exemptions it currently qualifies for may be modified or changed in ways that require PAA to incur significant additional compliance costs. Any such change or interpretation adverse to PAA could have a material adverse effect on its operations, revenues, expenses and profitability.

PAA has a history of incremental additions to the miles of pipelines it owns, both through acquisitions and internal growth projects. PAA has also increased its terminal and storage capacity and operate several facilities on or near navigable waters and domestic water supplies. Although PAA has implemented programs intended to maintain the integrity of its assets (discussed below), as it acquires additional assets it historically has observed an increase in the number of releases of liquid hydrocarbons into the environment. These releases expose PAA 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. PAA s refined products terminal 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 PAA s results of operations.

PAA currently devotes substantial resources to comply with DOT-mandated pipeline integrity rules. The 2006 Pipeline Safety Act requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. The DOT regulations include requirements for the establishment of pipeline integrity management programs and for protection of high consequence areas where a pipeline leak or rupture could produce significant adverse consequences. PAA has also developed and implemented certain pipeline integrity measures that go beyond regulatory mandate. See Items 1 and 2 Business and Properties Regulation.

For 2014 and beyond, PAA will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, PAA has implemented programs intended to maintain the integrity of its assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. PAA has an internal review process pursuant to which it examines various aspects of its 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 regulatory agency enforcement actions, PAA may elect (as a result of its own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade its pipeline systems to maintain environmental compliance and, in some cases, PAA may take pipelines out of service if it believes the cost of upgrades will exceed the value of the pipelines. PAA cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures but any such expenditures could be significant. See Item 3 Legal Proceedings Environmental.

PAA s profitability depends on the volume of crude oil, refined product, natural gas and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of its facilities, which can be negatively impacted by a variety of factors outside of its control.

PAA s profitability could be materially impacted by a decline in the volume of crude oil, natural gas, refined product and NGL transported, gathered, stored or processed at its facilities. A material decrease in crude oil or natural gas production or crude oil refining, as a result of depressed commodity prices, natural decline rates attributable to crude oil and natural reservoirs, a decrease in exploration and development activities, supply disruptions, economic conditions or otherwise, could result in a decline in the volume of crude oil, natural gas, refined product or NGL handled by PAA s facilities and other energy logistics assets.

For example, while advances in horizontal drilling and fracturing technology over the last several years have lead to increased oil and hydrocarbon production in North America, much of the incremental production is attributable to shale resource plays where production from wells decline very rapidly. As a result, a significant slow-down in the number of well completions, whether due to net wellhead prices falling below minimum required economic levels, reduced capital market access or increased capital costs for producers, adverse governmental or regulatory action or other factors, could lead to a significant decline in North American crude oil and hydrocarbon production. In turn, such a development could lead to reduced throughput on our pipelines and at our other facilities, which could have a material adverse effect on our business.

In addition, catastrophic accidents, such as the 2010 explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico and the resulting oil spill, could lead to increased governmental regulation of PAA s industry s operations in a number of areas, including health and safety, environmental, and licensing, any of which could restrict the supply of crude oil available for transportation and have a negative impact on its profitability.

Also, third-party shippers generally do not have long-term contractual commitments to ship crude oil on PAA s pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on PAA s pipelines could cause a significant decline in its revenues.

To maintain the volumes of crude oil PAA purchases in connection with its operations, PAA 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, PAA 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.

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Fluctuations in demand, which can be caused by a variety of factors outside of PAA s control, can negatively affect its operating results.

Demand for crude oil and other hydrocarbon products PAA handles is dependent upon a variety of factors, including price, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation, including climate change regulations, and technological advances in fuel economy and energy generation devices. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could increase the cost of consuming crude oil and other hydrocarbon products, thereby causing a reduction in the demand for such products. Demand also depends on the ability and willingness of shippers having access to PAA s transportation assets to satisfy their demand by deliveries through those assets.

Fluctuations in demand for crude oil, such as those caused by refinery downtime or shutdowns, can have a negative effect on PAA s operating results. Specifically, reduced demand in an area serviced by PAA s transportation systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by PAA s ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

Fluctuations in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products, increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL products, particularly propane, or other reasons, could result in a decline in the volume of NGL products PAA handles or a reduction of the fees it charges for its services. Also, increased supply of NGL products could reduce the value of NGL PAA handles and reduce the margins realized by it.

NGL and products produced from NGL also compete with products from global markets. Any reduced demand or increased supply for ethane, propane, normal butane, iso-butane or natural gasoline in the markets PAA accesses for any of the reasons stated above could adversely affect demand for the services PAA provides as well as NGL prices, which could negatively impact its operating results.

PAA s assets are subject to federal, state and provincial regulation. Rate regulation or a successful challenge to the rates PAA charges on its U.S. and Canadian pipeline systems may reduce the amount of cash it generates.

PAA s U.S. interstate common carrier liquids pipelines are subject to regulation by the FERC under the ICA. The ICA requires that tariff rates for liquids pipelines be just and reasonable and non-discriminatory. PAA is also subject to the Pipeline Safety Regulations of the DOT. PAA s intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

For PAA s U.S. interstate common carrier liquids pipelines subject to FERC regulation under the ICA, shippers may protest its pipeline tariff filings, file complaints against its existing rates, or the FERC can investigate on its own initiative. Under certain circumstances, the FERC could limit PAA s ability to set rates based on its costs, or could order PAA to reduce its 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.

PAA s 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 the NEB found the rates or terms of service relating to such pipeline to be unjust or unreasonable or unjustly discriminatory, the NEB could require PAA to change its rates, provide access to other shippers, or change its terms of service. A provincial authority could, on the application of a shipper or other interested party, investigate the tariff rates or PAA s terms and conditions of service relating to its provincially regulated proprietary pipelines. If it found PAA s 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 PAA to change its rates, provide access to other shippers, or otherwise alter its terms of service. Any reduction in PAA s tariff rates would result in lower revenue and cash flows.

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

PAA s cross border activities subject it 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.

PAA s sales of oil, natural gas, NGL and other energy commodities, and related transportation and hedging activities, expose it to potential regulatory risks.

The FTC, 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 PAA s physical sales of oil, natural gas, NGL or other energy commodities, and any related transportation and/or hedging activities that it undertakes, PAA is required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. PAA s sales may also be subject to certain reporting and other requirements. Additionally, to the extent that PAA enters into transportation contracts with natural gas pipelines that are subject to FERC regulation, it is subject to FERC requirements related to the use of such capacity. Any failure on PAA s part to comply with the regulations and policies of the FERC, the FTC or the Commodity Futures Trading Commission 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 PAA s business, results of operations, financial condition and its ability to make cash distributions to its partners.

The enactment and implementation of derivatives legislation could have an adverse impact on PAA s ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its business and increase the working capital requirement to conduct these hedging activities.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd Frank Act), enacted on July 21, 2010, established federal oversight and regulation of derivative markets and entities, such as PAA, that participate in those markets. The Dodd Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for, or linked to, certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on PAA is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing, and the associated rules could also require PAA, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption from such requirements. PAA does not utilize credit default swaps and PAA qualifies and expects to continue to qualify for the end-user exception from the mandatory clearing requirements for swaps entered into to hedge its interest rate risks. Should the CFTC designate commodity derivatives for mandatory clearing, PAA would expect to qualify for an end-user exception from the mandatory clearing requirements for swaps entered into to hedge its commodity price risk. However, the majority of PAA s financial derivative transactions used for hedging commodity price risks are currently executed and cleared over exchanges that require the posting of margin or letters of credit based on initial and variation margin requirements. Pursuant to the Dodd Frank Act, however, the CFTC or federal banking regulators may require the posting of collateral with respect to uncleared interest rate and commodity derivative transactions.

Posting of additional cash margin or collateral could affect PAA s liquidity (defined as unrestricted cash on hand plus available capacity under its credit facilities) and reduce PAA s ability to use cash for capital expenditures or other partnership purposes. A requirement to post additional cash margin or collateral could therefore reduce PAA s ability to execute hedges necessary to reduce commodity price exposures and protect cash flows. PAA could be at risk for reduced liquidity if the CFTC adopts rules and definitions that require companies, such as PAA, to post collateral for its uncleared derivative hedging activities. The proposed margin rules for uncleared swaps are not yet final and, therefore, the impact of such rules on PAA is uncertain at this time.

Even if PAA itself is not required to post additional cash margin or collateral for its derivative contracts, the banks and other derivatives dealers who are PAA s contractual counterparties will be required to comply with other new requirements under the Dodd Frank Act and related rules. The costs of such compliance may be passed on to customers such as PAA, thus decreasing the benefits to PAA of hedging transactions or reducing its profitability. The Dodd Frank Act also may require the counterparties to PAA s derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. In addition, implementation of the Dodd Frank Act and related rules and regulations could reduce the overall liquidity and depth of the markets for financial and other derivatives PAA utilizes in connection with its business, which could expose PAA to additional risks or limit the opportunities PAA is able to capture by limiting the extent to which PAA is able to execute its hedging strategies.

Finally, the Dodd Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. PAA s financial results could be adversely affected if a consequence of the Dodd Frank Act and implementing regulations is to reduce the volatility of commodity prices.

The full impact of the Dodd Frank Act and related regulatory requirements upon PAA s business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks PAA encounters, reduce PAA s ability to monetize or restructure its existing derivative contracts or increase PAA s exposure to less creditworthy counterparties. If PAA reduces its use of derivatives as a result of the Dodd Frank Act and regulations implementing the Dodd Frank Act, PAA s results of operations may become more volatile and its cash flows may be less predictable. Any of these consequences could have a material adverse effect on PAA, its financial condition and its results of operations.

Legislation and regulatory initiatives relating to hydraulic fracturing could reduce domestic production of crude oil and natural gas.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from unconventional geological formations. Recent advances in hydraulic fracturing techniques have resulted in significant increases in crude oil and natural gas production in many basins in the United States and Canada. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, and it is typically regulated by state and provincial oil and gas commissions. Hydraulic fracturing has been subject to increased scrutiny due to public concerns that it could result in contamination of drinking water supplies, and there have been a variety of legislative and regulatory proposals to prohibit, restrict, or more closely regulate various forms of hydraulic fracturing. Any legislation or regulatory initiatives that curtail hydraulic fracturing could reduce the production of crude oil and natural gas in the United States or Canada, and could thereby reduce demand for PAA s transportation, terminalling and storage services as well as its supply and logistics services.

PAA may not be able to compete effectively in its transportation, facilities and supply and logistics activities, and PAA s business is subject to the risk of a capacity overbuild of midstream energy infrastructure in the areas where it operates.

PAA faces competition in all aspects of its business and can give no assurances that it will be able to compete effectively against its competitors. In general, competition comes from a wide variety of players in a wide variety of contexts, including new entrants and existing players and in connection with day-to-day business, organic growth projects, acquisitions and joint venture activities. Some of PAA s competitors have capital resources many times greater than PAA s and control greater supplies of crude oil, natural gas or NGL.

A significant driver of competition in some of the markets where PAA operates (including, for example, the Eagle Ford, Permian Basin, and Rockies/Bakken areas) is the rapid development of new midstream energy infrastructure capacity driven by the combination of (i) significant increases in oil and gas production and development in the applicable production areas, both actual and anticipated, (ii) relatively low barriers to entry and (iii) generally widespread access to relatively low cost capital. While this environment presents opportunities for PAA, it is also exposed to the risk that these areas become overbuilt, resulting in an excess of midstream energy infrastructure capacity. Most midstream projects require several years of lead time to develop and companies like PAA that develop such projects are exposed (to varying degrees depending on the contractual arrangements that underpin specific projects) to the risk that expectations for oil and gas development in the particular area may not be realized or that too much capacity is developed relative to the demand for services that ultimately materializes. In addition, as an established player in some markets, PAA also faces competition from aggressive new entrants to the market that are willing to provide services at a discount in order to establish relationships and gain a foothold in the market. If PAA experiences a significant capacity overbuild in one or more of the areas where it operates, it could have a significant adverse impact on PAA s financial position, cash flows and ability to pay or increase distributions to its unitholders.

With respect to PAA s crude oil activities, its competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, refiners, industrial companies, independent gatherers, investment banks, brokers and marketers of widely varying sizes, financial resources and experience. PAA competes against these companies on the basis of many factors, including geographic proximity to production areas, market access, rates, terms of service, connection costs and other factors.

With respect to PAA s natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. PAA s natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain pipeline companies have existing storage facilities connected to their systems that compete with some of PAA s facilities.

With regard to PAA s NGL operations, it competes with large oil, natural gas and natural gas liquids companies that may, relative to PAA, have greater financial resources and access to supplies of natural gas and NGL. The principal elements of competition are rates, processing fees (e.g., extraction premiums) paid to the owners or aggregators of natural gas to be processed, geographic proximity to the natural gas or NGL mix, available processing and fractionation capacity, transportation alternatives and their associated costs, and access to end user markets.

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PAA 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 PAA s business activities has expanded, the breadth and depth of available insurance markets has contracted. As a result of these factors and other market conditions, premiums and deductibles for certain insurance policies has increased substantially. Accordingly, PAA can give no assurance that it will be able to maintain adequate insurance in the future at rates or on other terms PAA considers commercially reasonable. In addition, although PAA believes that it currently maintains adequate insurance coverage, insurance will not cover many types of interruptions or events that might occur and will not cover all risks associated with its operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. The occurrence of a significant event, the consequences of which are either not covered by insurance or not fully insured, or a significant delay in the payment of a major insurance claim, could materially and adversely affect PAA s financial position, results of operations and cash flows.

The terms of PAA s indebtedness may limit its ability to borrow additional funds or capitalize on business opportunities. In addition, PAA s future debt level may limit its future financial and operating flexibility.

As of December 31, 2013, PAA s consolidated debt outstanding was approximately $7.8 billion, consisting of approximately $6.7 billion principal amount of long-term debt (including senior notes) and approximately $1.1 billion of short-term borrowings. As of December 31, 2013, PAA had over $1.8 billion of available borrowing capacity under its senior unsecured revolving credit facility and its senior secured hedged inventory facility.

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

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

- credit rating agencies may view PAA s debt level negatively;

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

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

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

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

PAA s 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 PAA s 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 its assets or enter into a merger or consolidation. PAA s credit facility treats a change of control as an event of default and also requires PAA to maintain a certain debt coverage ratio. PAA s senior notes do not restrict distributions to unitholders, but a default under its 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 Indentures.

PAA s ability to access capital markets to raise capital on favorable terms will be affected by its debt level, its operating and financial performance, the amount of its current maturities and debt maturing in the next several years, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade PAA s credit ratings, then it could experience an increase in its borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, be unable to receive open credit from its 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 its common units. If PAA is unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, it might be forced to refinance some of its debt obligations through bank credit, as opposed to long-term public debt securities or equity securities, or sell assets. The price and terms upon which PAA 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 PAA s leverage may adversely affect its future financial and operating flexibility and thereby impact its ability to pay cash distributions at expected rates.

Increases in interest rates could adversely affect PAA s business.

As of December 31, 2013, PAA had approximately $7.8 billion of consolidated debt, of which approximately $6.7 billion was at fixed interest rates and approximately $1.1 billion was at variable interest rates. PAA is exposed to market risk due to the short-term nature of its commercial paper borrowings and the floating interest rates on its credit facilities. PAA s 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 PAA s supply and logistics segment results by increasing interest costs associated with the storage of hedged crude oil and NGL inventory.

Changes in currency exchange rates could adversely affect PAA s operating results.

Because PAA is a U.S. dollar reporting company and also conduct operations in Canada, it is exposed to currency fluctuations and exchange rate risks that may adversely affect the U.S. dollar value of its earnings, cash flow and partners capital under applicable accounting rules.

An impairment of goodwill or intangibles could reduce PAA s earnings.

At December 31, 2013, PAA had approximately $2.5 billion of goodwill and approximately $420 million of intangibles. 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. GAAP requires PAA to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. GAAP requires that PAA amortizes finite-lived intangibles over their estimated useful lives and test all of its intangibles for impairment when events or circumstances indicate the carrying value may not be recoverable. If PAA was to determine that any of its goodwill or intangibles were impaired, PAA would be required to take an immediate charge to earnings with a corresponding reduction of partners capital and increase in balance sheet leverage as measured by debt to total capitalization.

Marine transportation of crude oil has inherent operating risks.

PAA s supply and logistics operations include purchasing crude oil that is carried on third-party tankers or barges. Such waterborne cargos are at risk of being damaged or lost because of events such as marine disaster, inclement 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 , termination of contracts, governmental fines, penalties or restrictions on conducting business, higher insurance rates and damage to PAA s reputation and customer relationships generally. Although certain of these risks may be covered under PAA s insurance program, any of these circumstances or events could increase its costs or lower its revenues.

PAA is dependent on use of third-party assets for certain of its operations.

Certain of PAA s business activities require the use of third-party assets over which it may have little or no control. For example, a portion of PAA s storage and distribution business conducted in the Los Angeles basin receives waterborne crude oil through dock facilities operated by a third party in the Port of Long Beach. If at any time PAA s access to this dock was denied, and if access to an alternative dock could not be arranged, the volume of crude oil that it presently receives from its customers in the Los Angeles basin may be reduced, which could result in a reduction of facilities segment revenue and cash flow.

Non-utilization of certain assets, such as PAA s leased rail cars, could significantly reduce its profitability due fixed costs incurred to obtain the right to use such assets.

From time to time in connection with its business, PAA may lease or otherwise secure the right to use certain third party assets (such as rail cars, trucks, barges, ships, pipeline capacity, storage capacity and other similar assets) with the expectation that the revenues it generates through the use of such assets will be greater than the fixed costs it incurs pursuant to the applicable leases or other arrangements. However, when such assets are not utilized or are under-utilized, PAA s profitability could be negatively impacted because the revenues it earns are either non-existent or reduced, but it remains obligated to continue paying any applicable fixed charges, in addition to the potential of incurring other costs attributable to the non-utilization of such assets. For example, in connection with PAA s rail operations, it leases substantially all of its rail cars, typically pursuant to multi-year leases that obligate PAA to pay the applicable lease rate without regard to utilization. If business conditions are such that a portion of PAA s rail fleet is not utilized for any period of time due to reduced demand for the services they provide, PAA will still be obligated to pay the applicable fixed lease rate for such rail cars. In addition, during the period of time that PAA is not utilizing such rail cars, it will incur incremental costs associated with the cost of storing such rail cars and will continue to incur costs for maintenance and upkeep. Non-utilization of leased rail cars and other similar assets in connection with its business could have a significant negative impact on PAA s profitability and cash flows.

For various operating and commercial reasons, PAA may not be able to perform all of its obligations under its contracts, which could lead to increased costs and negatively impact financial results.

Various operational and commercial factors could result in an inability on PAA s part to satisfy its contractual commitments and obligations. For example, in connection with the provision of firm storage services and hub services to its natural gas storage customers, PAA enters into contracts that obligate PAA to honor its customers requests to inject gas into its storage facilities, withdraw gas from its facilities and wheel gas through its facilities, in each case subject to volume, timing and other limitations set forth in such contracts. The following factors could adversely impact PAA s ability to perform its obligations under these contracts:

a failure on the part of PAA s storage facilities to perform as expected, whether due to malfunction of equipment or facilities or realization of other operational risks;

a failure on PAA s part to create incremental storage capacity at its facilities due to reduced leaching rates, operational or other factors;

the operating pressure of PAA s storage facilities (affected in varying degree, depending on the type of storage cavern, by total volume of working and base gas, and temperature);

a variety of commercial decisions PAA makes from time to time in connection with the management and operation of its storage facilities. Examples include, without limitation, decisions with respect to matters such as (i) the aggregate amount of commitments PAA is willing to make with respect to wheeling, injection, and withdrawal services, which could exceed PAA s capabilities at any given time for various reasons, (ii) the timing of scheduled and unplanned maintenance or repairs, which can impact equipment availability and capacity, (iii) the schedule for and rate at which PAA conducts leaching activities at its facilities in connection with the creation of new salt caverns or the expansion of existing caverns, which can impact the amount of storage capacity PAA has available to satisfy its customers requests, (iv) the timing and aggregate volume of any base gas park and/or loan transactions PAA consummates, which can directly affect the operating pressure of PAA s storage facilities and (v) the amount of compression capacity and other gas handling equipment that PAA installs at its facilities to support gas wheeling, injection and withdrawal activities; and

adverse operating conditions due to hurricanes, extreme weather events or conditions, and operational problems or issues with third party pipelines, storage or production facilities.

Although PAA manages and monitors all of these various factors in connection with the ongoing operation of its natural gas storage facilities with the goal of performing all of its contractual commitments and obligations and optimizing revenue, one or more of the above factors may adversely impact PAA s ability to satisfy its injection, withdrawal or wheeling obligations under its storage contracts. In such event, PAA may be liable to its customers for losses or damages they suffer and/or PAA may need to incur costs or expenses in order to permit it to satisfy its obligations.

Cost reimbursements due to PAA s general partner may reduce PAA s cash available for distribution to its partners.

Prior to making any distribution to its partners, PAA will reimburse PAA GP and its affiliates, including officers and directors, for all expenses incurred on PAA s behalf (other than expenses related to the AAP Management Units). The reimbursement of expenses and the payment of fees could adversely affect PAA s ability to make distributions to its partners. PAA GP has sole discretion to determine the amount of these expenses. In addition, PAA GP and its affiliates may provide PAA with services for which PAA will be charged reasonable fees as determined by its general partner.

Cash distributions are not guaranteed and may fluctuate with PAA s performance and the establishment of financial reserves.

Because distributions on PAA s partnership interests are dependent on the amount of cash it generates, distributions to PAA s common unitholders may fluctuate based on PAA s performance, which will result in fluctuations in the amount of distributions ultimately received by AAP. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond PAA s control and the control of PAA GP. 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 PAA records losses and might not be made during periods when it records profits.

Tax Risks

As our only cash-generating assets consist of our partnership interest in AAP and its related direct and indirect interests in PAA, our tax risks are primarily derivative of the tax risks associated with an investment in PAA.

The tax treatment of PAA depends on its status as a partnership for U.S. federal income tax purposes, as well as it not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat PAA as a corporation or PAA becomes subject to additional amounts of entity-level taxation for state or foreign tax purposes, it would reduce the amount of cash available for distribution to us and increase the portion of our distributions treated as taxable dividends.

At December 31, 2013, we owned a 22.1% limited partner interest in AAP, which indirectly owns PAA s 2% general partner interest, and directly owns all of PAA s IDRs. Accordingly, the value of our indirect investment in PAA, as well as the anticipated after-tax economic benefit of an investment in our Class A shares, depends largely on PAA being treated as a partnership for federal income tax purposes, which requires that 90% or more of PAA s gross income for every taxable year consist of qualifying income, as defined in Section 7704 of the Internal Revenue Code of 1986, as amended (the Code).

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Despite the fact that PAA is a limited partnership under Delaware law and, unlike us, has not elected to be treated as a corporation for federal income tax purposes, it is possible, under certain circumstances, for PAA to be treated as a corporation for federal income tax purposes. Although we do not believe, based on its current operations, that PAA will be so treated, a change in PAA s business could cause it to be treated as a corporation for federal income tax purposes or otherwise subject it to federal income taxation as an entity.

Current law may change, causing PAA to be treated as a corporation for federal income tax purposes or otherwise subjecting PAA to entity-level taxation. In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, PAA is subject to entity-level tax on the portion of its income apportioned to Texas in the prior year. Imposition of any similar taxes on PAA in additional states will reduce its cash available for distribution to its partners.

If PAA were treated as a corporation for federal income tax purposes, it would pay federal income tax on its 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 PAA s partners, including AAP, would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to PAA s partners. Because a tax would be imposed upon PAA as a corporation, its cash available for distribution would be substantially reduced. Therefore, treatment of PAA as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to us, likely causing a substantial reduction in the value of our Class A shares.

PAA s partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects PAA to taxation as a corporation or otherwise subjects PAA to entity-level taxation for federal income tax purposes, PAA s minimum quarterly distribution and target distribution amounts will be adjusted downward by a percentage that is based on the applicable entity-level tax rate, including both federal and state tax burdens. Although it is impossible to make an accurate assessment of the impact without the specific details of any such new law or modification, in such event, it is likely the amount of distributions AAP receives from PAA and our resulting cash flows could be reduced substantially, which would adversely affect our ability to pay distributions to our shareholders.

Moreover, if PAA were treated as a corporation we would not be entitled to the deductions associated with our initial acquisition of interests in AAP or subsequent exchanges of retained AAP interests and Class B shares for our Class A shares. As a result, if PAA were treated as a corporation, (i) our liability for taxes would likely be higher, further reducing our cash available for distribution, and (ii) a greater portion of the cash we are able to distribute will be treated as a taxable dividend.

The tax treatment of publicly traded partnerships such as PAA 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 publicly traded partnerships, including PAA, may be modified by administrative, legislative or judicial changes, or differing interpretations at any time. Any modifications to the U.S. federal income tax laws that may be applied retroactively or prospectively could make it more difficult or impossible to meet the expectation of future cash distributions or reduce the cash available for distributions to our shareholders. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Currently, one such legislative proposal would eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which PAA relies for its treatment as a partnership for U.S. federal income tax purposes. PAA is unable to predict whether any of these changes or other proposals will be reintroduced or ultimately will be enacted. Any such changes could negatively impact the value of our indirect investment in PAA. Any modification to the U.S. federal income tax laws may 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.

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

PAA will be considered to have constructively terminated as a partnership for tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in its 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. PAA s termination would, among other things, result in the closing of its taxable year for all unitholders, which would result in PAA filing two tax returns for one fiscal year and could result in a deferral of depreciation deductions allowable in computing PAA s taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of PAA s taxable year may also result in more than twelve months of PAA s taxable income or loss being includable in his taxable income for the year of termination. PAA s termination currently would not affect its classification as a partnership for federal income tax purposes, but it would result in PAA being treated as a new partnership for tax purposes. If PAA were treated as a new partnership, PAA would be required to make new tax elections and could be subject to penalties if it was unable to determine that a termination occurred. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

Taxable gain or loss on the sale of our Class A shares could be more or less than expected.

If a holder sells our Class A shares, the holder will recognize a gain or loss equal to the difference between the amount realized and the holder s tax basis in those Class A shares. To the extent that the amount of our distributions exceeds our current and accumulated earnings and profits, the distributions will be treated as a tax free return of capital and will reduce a holder s tax basis in the Class A shares. We do not expect to have any earnings and profits for an extended period of time, which we estimate will include, at a minimum, each of the periods ending December 31, 2014, 2015, and 2016, Because our distributions in excess of our earnings and profits decrease a holder s tax basis in Class A shares, such excess distributions will result in a corresponding increase in the amount of gain, or a corresponding decrease in the amount of loss, recognized by the holder upon the sale of the Class A shares. Please read Summary of Tax Considerations Gain on Disposition of Class A Shares for a further discussion of the foregoing.

Our current tax treatment may change, which could affect the value of our Class A shares or reduce our cash available for distribution.

Our expectation that our initial acquisition of interests in AAP will result in deductions that will offset a substantial portion of our taxable income for an extended period of time following the closing of this offering and that such deductions will also result in our distributions not constituting taxable dividends for an extended period of time thereafter is based on current law with respect to the amortization of basis adjustments associated with our acquisition of interests in AAP. Similarly, our expectation that exchanges by the Legacy Owners of their retained interests in AAP and Class B shares in us for our Class A shares in the future will result in additional tax deductions is based on current law with respect to such exchanges. Changes in federal income tax law relating to such tax treatment could result in (i) our being subject to additional taxation at the entity level with the result that we would have less cash available for distribution, and (ii) a greater portion of our distributions being treated as taxable dividends. Moreover, we are subject to tax in numerous jurisdictions. Changes in current law in these jurisdictions, particularly relating to the treatment of deductions attributable to acquisitions of interests in AAP, could result in our being subject to additional taxation at the entity level with the result that we would have less cash available for distribution.

Any decrease in our Class A share price could adversely affect our amount of cash available for distribution.

Changes in certain market conditions may cause our Class A share price to decrease. If our Legacy Owners exchange their retained interests in AAP and Class B shares in us for our Class A shares at a point in time when our Class A share price is below the price at which Class A shares were sold in our initial public offering or in any subsequent exchange, the ratio of our income tax deductions to gross income would decline. This decline could result in our being subject to tax sooner than expected, our tax liability being greater than expected, or a greater portion of our distributions being treated as taxable dividends.

The IRS Forms 1099-DIV that our shareholders receive from their brokers may over-report dividend income with respect to our shares for U.S. federal income tax purposes, and failure to report dividend income in a manner consistent with the IRS Forms 1099-DIV may cause the IRS to assert audit adjustments to a shareholder s U.S. federal income tax return. For non-U.S. holders of our shares, brokers or other withholding agents may overwithhold taxes from dividends paid, in which case a shareholder generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to claim a refund of the overwithheld taxes.

Distributions we pay with respect to our shares will constitute dividends for U.S. federal income tax purposes only to the extent of our current and accumulated earnings and profits. Distributions we pay in excess of our earnings and profits will not be treated as dividends for U.S. federal income tax purposes; instead, they will be treated first as a tax-free return of capital to the extent of a shareholder s tax basis in their shares and then as capital gain realized on the sale or exchange of such shares. We may be unable to timely determine the portion of our distributions that is a dividend for U.S. federal income tax purposes.

For a U.S. holder of our shares, the IRS Forms 1099-DIV may not be consistent with our determination of the amount that constitutes a dividend for U.S. federal income tax purposes or a shareholder may receive a corrected IRS Form 1099-DIV (and may therefore need to file an amended federal, state or local income tax return). We will attempt to timely notify our shareholders of available information to assist with income tax reporting (such as posting the correct information on our website). However, the information that we provide to our shareholders may be inconsistent with the amounts reported by a broker on IRS Form 1099-DIV, and the IRS may disagree with any such information and may make audit adjustments to a shareholder s tax return.

For a non-U.S. holder of our shares, dividends for U.S. federal income tax purposes will be subject to withholding of U.S. federal income tax at a 30% rate (or such lower rate as may be specified by an applicable income tax treaty) unless the dividends are effectively connected with conduct of a U.S. trade or business. Please read Summary of Tax Considerations Consequences to Non-U.S. Holders. In the event that we are unable to timely determine the portion of our distributions that is a dividend for U.S. federal income tax purposes, or a shareholder s broker or withholding agent chooses to withhold taxes from distributions in a manner inconsistent with our determination of the amount that constitutes a dividend for such purposes, a shareholder s broker or other withholding agent may overwithhold taxes from distributions paid. In such a case, a shareholder generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to obtain a refund of the overwithheld tax.

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Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

General. In the ordinary course of business, we are involved 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 material adverse effect on our financial condition, results of operations or cash flows. Although we believe that our operations are presently in material compliance with applicable requirements, as we acquire and incorporate additional assets it is possible that the 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 whether such noncompliance initially developed before or after our acquisition.

Pemex Exploración y Producción v. Big Star Gathering Ltd L.L.P. et al. In two cases filed in the Texas Southern District Court in May 2011 and April 2012, Pemex Exploración y Producción (PEP) alleges that certain parties stole condensate from pipelines and gathering stations and conspired with U.S. companies (primarily in Texas) to import and market the stolen condensate. PEP does not allege that Plains was part of any conspiracy, but that it dealt in the condensate only after it had been obtained by others and resold to Plains Marketing, L.P. PEP seeks actual damages, attorney s fees, and statutory penalties from Plains Marketing, L.P. In February 2013, the Court granted Plains Marketing, L.P. s motion to be dismissed from the April 2012 lawsuit. In October 2013, the Court issued an order in the May 2011 lawsuit granting summary judgment in favor of Plains Marketing, L.P. with respect to all of PEP s remaining claims against Plains Marketing, L.P. In February 2014, the Court affirmed its order granting summary judgment in favor of Plains Marketing, L.P., denied PEP s motion for reconsideration, and issued a judgment dismissing all claims against Plains. PEP has the right to appeal such rulings.

PNG Merger. Purported class action lawsuits were filed on behalf of PNG unitholders challenging the PNG Merger. Two lawsuits were filed in the Delaware Court of Chancery in September 2013 and were consolidated under the caption In re PAA Natural Gas Storage, Limited Partnership Unitholder Litigation, C.A. No. 8908-VCL (which we refer to as the Consolidated Delaware Action). Two lawsuits were filed in Texas state court in September 2013 and were consolidated under the caption Vicars v. PNGS GP, LLC, et al., Cause No. 2013-52687 (Tex. Dist. Ct. Harris County) (which we refer to as the Consolidated Texas Action). Four lawsuits were filed in Texas federal court in October 2013 and were consolidated under the caption The DuckPond Trust, et al., v. PAA Natural Gas Storage, LP., et al., 4:13-cv-03170 (S.D. Tex.) (which we refer to as the Consolidated Federal Action).

Plaintiffs in the Consolidated Delaware Action generally allege that (i) the individual defendants breached fiduciary duties owed to PNG unitholders by allegedly approving the merger agreement at an unfair price and through an unfair process and by agreeing to certain deal protection devices; and (ii) the PNG Merger unfairly benefits certain members of PNG s board of directors. Plaintiffs also allege that PNG s general partner, PNG and other of our affiliates aided and abetted the alleged fiduciary breaches by the individual defendants.

Plaintiffs in the Consolidated Texas Action generally allege that (i) the individual defendants breached their duties owed to PNG s unitholders under PNG s partnership agreement as well as the implied covenant of good faith and fair dealing, and are engaging in self-dealing; and (ii) PNG s general partner, PNG and other of our affiliates have aided and abetted the defendant directors for the purpose of advancing their own interests and/or assisting such directors in connection with their breaches of their respective duties. In addition, the Consolidated Texas Action includes purported derivative claims on behalf of PNG based on the alleged breaches of duties by the individual defendants.

In February 2014, the Consolidated Federal Action was dismissed. Plaintiffs in the remaining actions generally seek, among other relief, to enjoin the transaction, rescission in the event the transaction is consummated, an order directing defendants to account to plaintiff and other members of the putative class for all damages caused by their breaches, money damages and an award of costs and disbursements, including reasonable attorneys fees. We cannot predict the outcome of these or any other lawsuits that might be filed, nor can we predict the amount of time and expense that will be required to resolve these lawsuits. We intend to defend vigorously against these and any other actions. See Note 1 to our Consolidated Financial Statements for a description of the PNG Merger.

Environmental

General

Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. These releases can result from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

At December 31, 2013, our estimated undiscounted reserve for environmental liabilities totaled approximately $93 million, of which approximately $11 million was classified as short-term and approximately $82 million was classified as long-term. At December 31, 2012, our reserve for environmental liabilities totaled approximately $96 million, of which approximately $13 million was classified as short-term and approximately $83 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in Accounts payable and accrued liabilities and Other long-term liabilities and deferred credits, respectively, on our Consolidated Balance Sheets. At December 31, 2013 and 2012, we had recorded receivables totaling approximately $10 million and $42 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly reflected in Trade accounts receivable and other receivables, net on our Consolidated Balance Sheets.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional liabilities. 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.

Rainbow Pipeline Release

During April 2011, we experienced a crude oil release of approximately 28,000 barrels of crude oil on a remote section of our Rainbow Pipeline located in Alberta, Canada. Since the release and through December 31, 2013, we spent approximately $70 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of December 31, 2013, we did not have any material outstanding liabilities or insurance receivables relating to this release. On February 26, 2013, the AER issued a report detailing four enforcement actions against PMC for failure to comply with certain regulatory requirements in connection with the release, including requirements related to operations and maintenance procedures, leak detection and response, backfill and compaction procedures and emergency response plan testing. PMC is in the process of taking appropriate actions necessary to respond to and comply with the enforcement actions set forth in the report, including the implementation of additional risk assessment procedures and the taking of other actions designed to minimize the risk that similar incidents occur in the future and enhance the effectiveness of PMC s response to any such future incidents. In addition, on April 23, 2013, the Alberta Crown Prosecutor filed civil charges under the Environmental Protection and Enhancement Act against PMC relating to the release. To date, PMC has not been assessed any fines or penalties related to this release; however, such fines or penalties may be assessed in the future and are not expected to be material.

Rangeland Pipeline Release

During June 2012, we experienced a crude oil release on a section of our Rangeland Pipeline located near Sundre, Alberta, Canada. Approximately 3,000 barrels were released into the Red Deer River and were contained downstream in the Gleniffer Reservoir. Remediation activities in the reservoir area were completed by June 30, 2012, remediation of the remaining impacted areas of government-owned lands was completed by September 30, 2012 and interim closure, in respect of those lands, was received from the applicable regulatory agencies. Monitoring will continue into 2014, and a long-term monitoring plan has been developed and implemented in accordance with regulatory requirements. Through December 31, 2013, we spent approximately $46 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities. This release is currently under investigation by the AER, which also intends to perform an audit of PMC s operations. Although the AER s final investigation is not

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complete, on July 4, 2013, the AER issued four enforcement actions against PMC citing failure to inspect water crossings, failure to complete an engineering assessment to determine suitability of continued operation of the Rangeland Pipeline, failure to maintain updated emergency response plans, and failure to conduct regular public awareness programs. To date, no fines or penalties have been assessed against PMC with respect to this release; however, it is possible that fines or penalties may be assessed against PMC in the future and are not expected to be material.

Bay Springs Pipeline Release

During February 2013, we experienced a crude oil release of approximately 120 barrels on a portion of one of our pipelines near Bay Springs, Mississippi. Most of the released oil was contained within our pipeline right of way, but some of the released oil entered a nearby waterway where it was contained with booms. The EPA has issued an administrative order requiring us to take various actions in response to the release, including remediation, reporting and other actions, and we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was approximately $6 million, which has been recognized in Field operating costs on our Consolidated Statement of Operations.

Kemp River Pipeline Release

During May and June 2013, two separate releases were discovered on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the release of approximately 700 barrels of condensate and light crude oil. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. We estimate that the aggregate clean-up and remediation costs associated with these releases will be approximately $15 million which we have recognized in Field operating costs on our Consolidated Statement of Operations.

Insurance

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 various types of insurance that we consider adequate to cover our operations and certain assets. The insurance policies are subject to deductibles or self-insured retentions that we consider reasonable. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues.

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 with respect to our operations. In the future, we may not be able to maintain insurance at levels that we consider adequate for rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain insurance programs. For example, the market for hurricane- or windstorm-related property damage coverage has remained difficult the last few years. The amount of coverage available has been limited, costs have increased substantially and deductibles have increased as well.

In 2011, we elected not to renew our hurricane insurance, and, instead, to self-insure this risk. Our assessment of the current availability of coverage and associated rates has led us to the decision to continue to self-insure. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims which we have renewed at our historic coverage levels. In addition, although we believe that we have established adequate reserves to the extent such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Item 4. ***Mine Safety Disclosures***

Not applicable.

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PART II

Item 5. *Market for Registrant s Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities*

Our Class A shares are listed and traded on the New York Stock Exchange (NYSE) under the symbol PAGP. As of February 20, 2014, there were approximately 18,100 record holders and beneficial owners (held in street name). As of March 6, 2014, there were 135,833,637 Class A shares outstanding and the closing market price for our Class A shares was $28.04 per share.

The following table sets forth high and low sales prices for our Class A shares and the cash distribution declared per Class A share for the periods indicated:

	Class A share Price Range High		Low		Cash Distribution (1) (2)
4th Quarter 2013 (3)	$ 27.04		$ 21.50		$ 0.12505

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

(2) The distribution paid for the fourth quarter of 2013 was prorated for the period from October 21, 2013 (the date of closing of our IPO) through December 31, 2013, which corresponds to a distribution of $0.15979 per Class A share before proration, assuming our ownership of AAP for the full fourth quarter of 2013.

(3) Our Class A shares did not commence trading on the NYSE until October 2013.

Our Class B shares are not listed or traded on any stock exchange.

Our Class A shares may be used as a form of compensation to our employees and directors. 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.

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

Use of Proceeds from Sale of Securities

On October 16, 2013, we commenced the IPO of our Class A shares pursuant to our Registration Statement on Form S-1, Commission File No. 333-190227, which was declared effective by the Securities and Exchange Commission on October 15, 2013. Barclays Capital Inc., Goldman, Sachs & Co., JP Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., UBS Securities LLC and Wells Fargo Securities, LLC acted as joint book-running managers of the offering.

In October 2013, we issued 132,382,094 Class A shares, which included 4,382,094 Class A shares issued pursuant to partial exercise of the underwriters over-allotment option, at a price per share of $22.00. After deducting underwriting discounts and commissions of approximately $87 million paid to the underwriters, estimated offering expenses of approximately $5 million, the net proceeds from the IPO were approximately $2.8 billion. We distributed all of the net proceeds to the existing owners of AAP who sold a portion of their interests in AAP in connection with the offering.

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Cash Distribution Policy

Our partnership agreement requires that, within 55 days after the end of each quarter, we distribute all of our available cash to Class A shareholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the date of determination of available cash for the distribution in respect of such quarter (including expected distributions from AAP in respect of such quarter), less the amount of cash reserves established by our general partner, which will not be subject to a cap, to:

- comply with applicable law or any agreement binding upon us or our subsidiaries (exclusive of PAA and its subsidiaries);
- provide funds for distributions to shareholders;
- provide for future capital expenditures, debt service and other credit needs as well as any federal, state, provincial or other income tax that may affect us in the future;
- permit us to pay a ratable amount to AAP as necessary to permit AAP to make required capital contributions to PAA to maintain PAA GP s 2% general partner interest upon the issuance of additional partnership securities by PAA; or
- provide for the proper conduct of our business;

As of December 31, 2013, our only cash-generating assets consisted of 133,833,637 AAP units, which represent a 22.1% limited partner interest in AAP. AAP currently receives all of its cash flows from its direct ownership of all of PAA s incentive distribution rights and its indirect ownership of the 2% general partner interest in PAA. Therefore, our cash flow and resulting ability to make distributions will be completely dependent upon the ability of PAA to make distributions to AAP in respect of those partnership interests. The actual amount of cash that PAA, and correspondingly AAP, will have available for distribution will primarily depend on the amount of cash PAA generates from its operations. Also, under the terms of the agreements governing AAP and PAA s debt, they 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 Agreements, PAA Commercial Paper Program and Indentures.

Although not required to do so, in response to past requests by PAA management in connection with PAA s acquisition activities, AAP has, from time to time, agreed to reduce the amounts due to it as incentive distributions. Such modifications were implemented with a view toward enhancing PAA s competitiveness for such acquisitions and managing the overall cost of equity capital while achieving an appropriate balance between short-term and long-term accretion to PAA s limited partners and the holders of its general partner interest and IDRs. AAP agreed to reduce the amount of its incentive distribution by $3.75 million per quarter for distributions paid during 2013, $6.75 million for the distribution paid in February 2014, $5.5 million per quarter thereafter through November 2015, $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. These reductions were agreed to in connection with the BP NGL Acquisition and the completion of the PNG Merger on

December 31, 2013. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL Acquisition. See Note 1 to our Consolidated Financial Statements for further discussion of the PNG Merger.

Issuer Purchases of Equity Securities

We did not repurchase any of our Class A shares during the fourth quarter of 2013, and we do not have any announced or existing plans to repurchase any of our Class A shares.

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

The following tables set forth selected historical consolidated financial and other information for PAGP as of the dates and for the periods indicated. The selected consolidated statements of operations data for the year ended December 31, 2013 include results attributable to PAGP from October 21, 2013 (the date of closing PAGP s IPO) through December 31, 2013, plus results for Plains All American GP LLC (GP LLC), the predecessor entity to PAGP, prior to October 21, 2013.

The selected historical statements of operations and cash flow data for the years ended December 31, 2013, 2012 and 2011 and balance sheet data as of December 31, 2013 and 2012 is derived from the audited financial statements of PAGP (and GP LLC as discussed above) included elsewhere in this document. The selected historical statements of operations and cash flow data for the year ended December 31, 2010 and 2009 and the balance sheet data as of December 31, 2011, 2010 and 2009 are derived from the unaudited financial statements of GP LLC that are not included elsewhere in this document.

The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(in millions, except for per share data)				
Statement of operations data:					
Total revenues	$ 42,249	$ 37,797	$ 34,275	$ 25,893	$ 18,520
Net income	$ 1,374	$ 1,118	$ 987	$ 501	$ 568
Net income attributable to PAGP	$ 15	$ 3	$ 2	$ 2	$ 1
Per share data:					
Basic and diluted net income per Class A share (1)	$ 0.10	N/A	N/A	N/A	N/A
Balance sheet data (at end of period):					
Total assets	$ 21,453	$ 19,259	$ 15,414	$ 13,734	$ 12,388
Long-term debt	$ 7,230	$ 6,520	$ 4,720	$ 4,831	$ 4,342
Total debt	$ 8,343	$ 7,606	$ 5,406	$ 6,161	$ 5,416
Partners capital/Members equity:					
Partners capital/Members equity (excluding noncontrolling interests)	$ 1,035	$	$	$	$
Noncontrolling interests	7,244	6,968	5,794	4,391	3,977
Total Partners capital/Members equity	$ 8,279	$ 6,968	$ 5,794	$ 4,391	$ 3,977
Other data:					
Net cash provided by operating activities	$ 1,948	$ 1,232	$ 2,357	$ 248	$ 357
Net cash used in investing activities	$ (1,653)	$ (3,392)	$ (2,020)	$ (851)	$ (686)
Net cash provided by/(used in) financing activities	$ (274)	$ 2,159	$ (337)	$ 613	$ 348
Capital expenditures:					
Acquisitions	$ 19	$ 2,286	$ 1,404	$ 407	$ 393
Internal growth projects	$ 1,622	$ 1,185	$ 531	$ 355	$ 379
Maintenance	$ 176	$ 170	$ 120	$ 93	$ 81

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	Year Ended December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
Volumes (2)(3)					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	3,595	3,373	2,942	2,889	2,836
Trucking	117	106	105	97	85
Transportation segment total	3,712	3,479	3,047	2,986	2,921
Facilities segment:					
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	94	90	70	61	56
Rail load / unload volumes (average volumes in thousands of barrels per day)	221				
Natural gas storage (average monthly capacity in billions of cubic feet)	96	84	71	47	26
NGL fractionation (average volumes in thousands of barrels per day)	96	79	14	14	15
Facilities segment total (average monthly volumes in millions of barrels)	120	106	82	70	61
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	859	818	742	620	612
NGL sales	215	182	103	96	105
Waterborne cargos	4	3	21	68	55
Supply and Logistics segment total	1,078	1,003	866	784	772

(1) Attributable to post-IPO period, October 21, 2013 through December 31, 2013.

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

(3) Facilities segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the year and divided by the number of months in the year; (iii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude British thermal unit (Btu) equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation 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, including periods prior to the closing of our IPO on October 21, 2013. Such analysis should be read in conjunction with our historical consolidated financial statements and accompanying notes. For ease of reference, we refer to the historical results of Plains All American GP LLC (GP LLC) prior to our IPO as being our historical financial results. Unless the context otherwise requires, references to we, us, our, and PAGP are intended to mean the business and operations of PAGP and its consolidated subsidiaries since October 21, 2013. When used in the historical context (i.e. prior to October 21, 2013), these terms are intended to mean the business and operations of GP LLC and its consolidated subsidiaries.

Our discussion and analysis includes the following:

- Executive Summary
- Company Overview
- Overview of Operating Results, Capital Investments and Significant Activities

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- 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 are a Delaware limited partnership formed on July 17, 2013 to own an interest in the general partner and incentive distribution rights (IDRs) of Plains All American Pipeline, L.P (PAA), a publicly traded Delaware limited partnership. Although we were formed as a limited partnership, we have elected to be taxed as a corporation for United States federal income tax purposes. As of December 31, 2013, we owned a 22.1% limited partner interest in AAP, and the remaining limited partner interests in AAP continue to be held by the owners of AAP immediately prior to our IPO (the Legacy Owners). AAP is a Delaware limited partnership that directly owns all of PAA s incentive distribution rights and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP LLC (PAA GP), a Delaware limited liability company that directly holds the 2% general partner interest in PAA.

Through a series of transactions prior to our IPO with our general partner and the owners of GP LLC, a Delaware limited liability company formed on May 2, 2001 that manages the business and affairs of PAA and AAP, GP LLC s general partner interest in AAP became a non-economic interest, and we became the owner of a 100% managing member interest in GP LLC. Since we are the managing member of and control GP LLC, which in turn effectively controls PAA we reflect our ownership in PAA, as well as its subsidiaries, on a consolidated basis in accordance with generally accepted accounting principles. Accordingly, our financial results are combined with those of GP LLC and PAA as well as with their subsidiaries. As such, our results of operations as discussed below do not differ materially from the results of operations of PAA.

PAA owns and operates midstream energy infrastructure and provides logistics services for crude oil, natural gas liquids (NGL), natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas (LPG) such as propane and butane. When used in this Form 10-K, NGL refers to all NGL products including LPG. PAA owns an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. On average, PAA handles over 3.5 million barrels per day of crude oil and NGL on its pipelines.

Overview of Operating Results, Capital Investments and Significant Activities

During 2013, net income was approximately $1.374 billion, as compared to net income of approximately $1.118 billion recognized during 2012. Major items impacting the favorable performance between periods include contributions from the USD Rail Terminal and BP NGL Acquisitions, which were completed in December 2012 and April 2012, respectively, incremental fee-based contributions associated with acquisition and expansion capital invested in our Transportation and Facilities segments and favorable unit margins in our Supply and Logistics segment.

The favorable unit margins in the Supply and Logistics segment were driven by our NGL marketing operations, which benefited from improved market conditions and higher demand, as well as additional sales volumes related to the BP NGL Acquisition noted above. However, such results were partially offset by the impact of less favorable crude oil market conditions, particularly narrower crude oil differentials during much of 2013.

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Other significant items impacting the comparison to 2012 include:

- Decreased depreciation and amortization expense, largely driven by one-time asset impairment charges of approximately $168 million recognized during the comparative 2012 period; and

- Increased income tax expense resulting from an increased proportion of earnings subject to Canadian federal and provincial taxes, primarily driven by the stronger performance from our existing operations and operations related to the BP NGL Acquisition.

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2013, 2012 and 2011 that have impacted our results of operations. The following table summarizes our capital expenditures for acquisitions, internal growth projects and maintenance capital for the periods indicated (in millions):

	For the Year Ended December 31,		
	2013	2012	2011
Acquisition capital (1)	$ 19	$ 2,286	$ 1,404
Internal growth projects	1,622	1,185	531
Maintenance capital	176	170	120
	$ 1,817	$ 3,641	$ 2,055

(1) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, PAA issued approximately 14.7 million of its common units with a value of approximately $760 million.

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under credit facilities and the issuance of senior notes. Businesses acquired impact our results of operations commencing on the closing 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. Information regarding acquisitions completed in 2013, 2012 and 2011 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
2013 Total (1)	09/01/2013	$ 19	Transportation

BP NGL Acquisition (2)	04/01/2012	$	1,633	Transportation, Facilities and Supply and Logistics
US Development Group Crude Oil Rail Terminals	12/13/2012		503	Facilities
Other	Various		150	Transportation, Facilities and Supply and Logistics
2012 Total		$	2,286	
Southern Pines	02/09/2011	$	765	Facilities
Gardendale Gathering System	11/29/2011		349	Transportation
Western Pipeline and Storage Assets	12/29/2011		220	Facilities and Transportation
Other	Various		70	Transportation, Facilities and Supply and Logistics
2011 Total		$	1,404	

(1) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, PAA issued approximately 14.7 million of its common units with a value of approximately $760 million.

(2) Total BP NGL Acquisition purchase price was approximately $1.683 billion. A cash deposit of $50 million was paid during 2011 and is reflected in Other in the 2011 Total in the table above.

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Internal Growth Projects

Our 2013 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2013, 2012 and 2011 projects (in millions):

Projects		2013		2012		2011
Mississippian Lime Pipeline (1)	$	163	$	54	$	
Gulf Coast Pipeline (1)		125		13		
Rainbow II Pipeline		124		79		44
Yorktown Terminal Projects		114		39		
Eagle Ford Area Pipeline Projects (1) (2)		86		88		2
Rail Terminal Projects (4)		83		41		27
White Cliffs Expansion (5)		73		1		
Fort Saskatchewan Facility Expansions		73				
Cactus Pipeline (1)		64				
Eagle Ford JV Project (1) (3)		60		132		18
Spraberry Area Pipeline Projects (1)		51		91		
St. James Expansions (1)		51		46		4
Western Oklahoma Pipeline (1)		50				
Natural Gas Storage (multiple projects) (1)		45		61		89
Cushing Terminal Expansions (1)		38		31		41
Gulf Coast Gas Processing Facility Enhancements		36				
Shafter Expansion		28		21		2
Other projects		358		488		304
Total	$	1,622	$	1,185	$	531

(1) These projects will continue into 2014. See Liquidity and Capital Resources Acquisitions, Capital Expenditures and Distributions Paid to Our Class A Shareholders and Noncontrolling Interests 2014 Capital Expansion Projects.

(2) Includes pipeline, tankage and condensate stabilization.

(3) Includes net expenditures associated with the formation of Eagle Ford Pipeline LLC in 2012, as well as subsequent contributions related to our 50% interest.

(4) Includes Manitou, ND, Bakersfield, CA, Tampa, CO, and Van Hook, ND rail projects.

(5) Represents contributions related to our 35.7% investment interest in the White Cliffs Pipeline.

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 (GAAP). 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 GAAP and rules and regulations of the United States Securities and Exchange Commission (SEC) 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. On a regular basis, we evaluate our assumptions, judgments and estimates. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

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We believe that the assumptions, judgments and estimates involved in the accounting for our (i) purchase and sales accruals, (ii) fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) fair value of derivatives, (iv) accruals and contingent liabilities, including our equity-indexed compensation plan accruals, (v) property and equipment and depreciation expense and (vi) allowance for doubtful accounts have the greatest potential impact on our Consolidated Financial Statements. These areas are key components of our results of operations and are based on complex rules which require us to make judgments and estimates, so we consider these to be our critical accounting estimates. Such critical accounting estimates are discussed further as follows:

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, 2013, we estimate that approximately 1% and 2% of annual revenues and cost of sales were recorded using sales and purchase estimates, respectively. Accordingly, a hypothetical variance of 10% from both of these estimates, either up or down in tandem, would impact annual revenues, cost of sales, operating income and net income by 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 Financial Accounting Standards Board (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 recorded. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. With exception to our equity method investments, 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 future revenues, future cash flows and 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 did not have any material goodwill impairments in 2013, 2012 or 2011. See Note 8 to our Consolidated Financial Statements for a further discussion of goodwill.

Fair Value of Derivatives. Our derivatives are reported at fair value as either assets or liabilities with changes in fair value recognized in either earnings or accumulated other comprehensive income (AOCI). The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the 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. See Note 11 to our Consolidated Financial Statements for a discussion regarding derivatives and risk management activities.

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Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, asset retirement obligations, equity-indexed compensation plan accruals (as further discussed below), bonus accruals 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, 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 hypothetical 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 $15 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-Indexed Compensation Plan Accruals. We accrue compensation expense (referred to herein as equity-indexed compensation expense) for outstanding equity-indexed compensation awards. Under GAAP, we are required to estimate the fair value of our outstanding equity-indexed compensation awards and recognize that fair value as compensation expense over the service period. For equity-indexed compensation awards that contain a performance condition, the fair value of the award is recognized as compensation expense only if the attainment of the performance condition is considered probable. 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-indexed compensation awards.

We recognized total compensation expense of approximately $116 million, $101 million and $110 million in 2013, 2012 and 2011, respectively, related to awards granted under our various equity-indexed compensation plans. We cannot provide assurance that the actual fair value of our equity-indexed compensation awards will not vary significantly from estimated amounts. See Note 15 to our Consolidated Financial Statements.

Property and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. These estimates are based on various factors including condition, manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. Any evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property 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 event or circumstance that may be indicative of an impairment;
- the grouping of assets;

- the intention of holding , abandoning or 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 2013, 2012 and 2011, we recognized losses on impairments of long-lived assets of approximately $20 million, $168 million and $5 million, respectively. The impairments recognized in 2013 and 2011 were predominantly related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and, in some instances, we utilized other assets to handle these activities. The impairments recognized in 2012 primarily related to our Pier 400 terminal project and the anticipated sale of certain refined products pipeline systems and related assets. See Note 6 to our Consolidated Financial Statements for further discussion regarding impairments.

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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

See Note 2 to our Consolidated Financial Statements for information regarding the effect of recent accounting pronouncements on our consolidated financial statements.

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 18 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 PAGP.

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 our 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. 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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The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP (in millions, except for per share amounts):

	For the Twelve Months Ended December 31,			Favorable/(Unfavorable)			
				2013-2012		2012-2011	
	2013	2012	2011	$	%	$	%
Transportation segment profit	$ 729	$ 710	$ 555	$ 19	3%	$ 155	28%
Facilities segment profit	616	482	358	134	28%	124	35%
Supply and Logistics segment profit	822	753	647	69	9%	106	16%
Total segment profit	2,167	1,945	1,560	222	11%	385	25%
Unallocated general and administrative expenses	(1)			(1)	N/A		%
Depreciation and amortization	(378)	(483)	(250)	105	22%	(233)	(93)%
Interest expense	(309)	(295)	(259)	(14)	(5)%	(36)	(14)%
Other income/(expense), net	1	6	(19)	(5)	(83)%	25	132%
Income tax expense	(106)	(55)	(45)	(51)	(93)%	(10)	(22)%
Net income	1,374	1,118	987	256	23%	131	13%
Net income attributable to noncontrolling interests	(1,359)	(1,115)	(985)	(244)	(22)%	(130)	(13)%
Net income attributable to PAGP	$ 15	$ 3	$ 2	$ 12	400%	$ 1	50%
Net income attributable to PAGP:							
Basic and diluted net income per Class A share (1)	$ 0.10	N/A	N/A				
Basic and diluted weighted average number of Class A shares outstanding (1)	132	N/A	N/A				

(1) Attributable to post-IPO period, October 21, 2013 through December 31, 2013.

Transportation Segment

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

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

				Favorable/(Unfavorable)			
Operating Results (1)	Year Ended December 31,			2013-2012		2012-2011	
(in millions, except per barrel amounts)	2013	2012	2011	$	%	$	%
Revenues							
Tariff activities	$ 1,293	$ 1,232	$ 1,005	$ 61	5%	$ 227	23%
Trucking	205	184	160	21	11%	24	15%
Total transportation revenues	1,498	1,416	1,165	82	6%	251	22%

Cost and Expenses							
Trucking costs	(147)	(134)	(115)	(13)	(10)%	(19)	(17)%
Field operating costs (excluding equity-indexed compensation expense)	(528)	(468)	(387)	(60)	(13)%	(81)	(21)%
Equity-indexed compensation expense - operations	(18)	(16)	(14)	(2)	(13)%	(2)	(14)%
Segment general and administrative expenses (2) (excluding equity-indexed compensation expense)	(101)	(96)	(69)	(5)	(5)%	(27)	(39)%
Equity-indexed compensation expense - general and administrative	(39)	(30)	(38)	(9)	(30)%	8	21%
Equity earnings in unconsolidated entities	64	38	13	26	68%	25	192%
Segment profit	$ 729	$ 710	$ 555	$ 19	3%	$ 155	28%
Maintenance capital	$ 123	$ 108	$ 86	$ (15)	(14)%	$ (22)	(26)%
Segment profit per barrel	$ 0.54	$ 0.56	$ 0.50	$ (0.02)	(4)%	$ 0.06	12%

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Average Daily Volumes (in thousands of barrels per day) (3)	Year Ended December 31, 2013	2012	2011	Favorable/(Unfavorable) 2013-2012 Volumes	%	2012-2011 Volumes	%
Tariff activities							
Crude Oil Pipelines							
All American	40	33	35	7	21%	(2)	(6)%
Bakken Area Systems	131	130	130	1	1%		%
Basin / Mesa	718	696	566	22	3%	130	23%
Capline	151	146	160	5	3%	(14)	(9)%
Eagle Ford Area Systems	102	23	5	79	343%	18	360%
Line 63 / Line 2000	113	128	114	(15)	(12)%	14	12%
Manito	46	57	66	(11)	(19)%	(9)	(14)%
Mid-Continent Area Systems	281	271	218	10	4%	53	24%
Permian Basin Area Systems	581	461	404	120	26%	57	14%
Rainbow	124	145	142	(21)	(14)%	3	2%
Rangeland	60	62	59	(2)	(3)%	3	5%
Salt Lake City Area Systems	131	149	146	(18)	(12)%	3	2%
South Saskatchewan	51	60	52	(9)	(15)%	8	15%
White Cliffs	23	18	13	5	28%	5	38%
Other	725	703	730	22	3%	(27)	(4)%
NGL Pipelines							
Co-Ed	56	44		12	27%	44	N/A
Other	194	131		63	48%	131	N/A
Refined Products Pipelines	68	116	102	(48)	(41)%	14	14%
Tariff activities total	3,595	3,373	2,942	222	7%	431	15%
Trucking	117	106	105	11	10%	1	1%
Transportation segment total	3,712	3,479	3,047	233	7%	432	14%

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

(2) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(3) Volumes associated with acquisitions represent total volumes (attributable to our interest) 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. Revenue from our pipeline capacity leases generally reflects a negotiated amount.

The following is a discussion of items impacting Transportation segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. As noted in the table above, our total Transportation segment revenues, net of trucking costs, and volumes increased year-over-year for each comparative period presented. Our Transportation segment results were impacted by the following for the years ended December 31, 2013, 2012 and 2011:

- North American Crude Oil Production and Related Expansion Projects For the year ended December 31, 2013, the favorable volume and revenue variances experienced were primarily due to increased producer drilling activities as well as the completion of certain of our expansion projects, most notably on our Permian Basin and Eagle Ford Area Systems and our Basin and Mesa pipelines. The Permian Basin Area Systems also benefited from increased movements to a new third-party pipeline connected to Gulf Coast markets. We estimate that increased production combined with our phased-in expansion projects increased revenues by approximately $40 million for the annual 2013 period over the comparable 2012 period.

Increased producer drilling activities and phased-in expansion projects also resulted in favorable volume and revenue variances for the year ended December 31, 2012 over the comparative 2011 period, most notably on our Basin and Mesa pipelines and Permian Basin and Mid-Continent Area Systems. We estimate that increased production combined with our phased-in expansion projects increased revenues by approximately $50 million for the annual 2012 period over the comparable 2011 period.

- Rate Changes Revenues on our pipelines are impacted by various rate changes that may occur during the period. These rate changes primarily include the indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate and Canadian pipelines or other negotiated rate changes. The upward indexings effective July 1, 2011, 2012 and 2013 favorably impacted revenues on a majority of our FERC regulated pipelines. However, during the third quarter of 2013, as a result of market factors, we lowered our tariff rates on certain of our FERC regulated pipelines relative to 2012 rates, which partially offset the favorable impact of the upward indexing effective July 1, 2013. Revenues for both the 2013 and 2012 periods were also favorably impacted by increasing tariff rates on certain of our non-FERC regulated pipelines.

We estimate that the collective impact of these rate changes increased revenues by approximately $50 million for 2013 compared to 2012, and by approximately $45 million for 2012 compared to 2011.

- BP NGL Acquisition Assets We acquired pipelines through the BP NGL Acquisition completed on April 1, 2012. These assets contributed approximately $27 million of additional tariff revenues for the year ended December 31, 2013 over the year ended December 31, 2012, which was primarily related to the benefit from a full period of ownership of these assets (as we only owned the assets for nine months of 2012). This increase excludes the unfavorable impacts related to decreased tariff rates and weather-related downtime on our Co-Ed pipeline, as discussed elsewhere in this section.

The BP NGL Acquisition assets generated tariff revenues of approximately $89 million and increased volumes by approximately 175,000 barrels per day for the year ended December 31, 2012 over the year ended December 31, 2011.

- Loss Allowance Revenue As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The loss allowance revenue decreased by approximately $23 million for 2013 compared to 2012 primarily due to a lower average realized price per barrel (including the impact of gains and losses from derivative-related activities) and lower volumes. The loss allowance revenue increased by approximately $13 million for 2012 compared to 2011 primarily due to higher loss allowance volumes, partially offset by a lower average realized price per barrel compared to 2011 (including the impact of losses from derivative-related activities).

- Weather-Related Downtime During the second and third quarters of 2013, our Rangeland, South Saskatchewan and Co-Ed pipelines in Canada were shut down due to high river flow rates and flooding in the surrounding area. We estimate that the downtime on these pipelines negatively impacted revenues and volumes by approximately $15 million to $20 million and 15,000 to 20,000 barrels per day, respectively, for the year ended December 31, 2013.

- Rail Impact Volumes for the 2013 period, primarily on our Manito and Rainbow pipelines and certain pipelines included in our Bakken Area Systems, were unfavorably impacted by producer decisions to deliver more crude oil to rail loading facilities in the area. We estimate that the impact to revenues was approximately $20 million for the year ended December 31, 2013 and that volumes decreased by approximately 25,000 to 30,000 barrels per day for the period. Although to a lesser extent, volumes in the 2012 period compared to 2011 were also unfavorably impacted by producer decisions to deliver more crude oil to rail loading facilities, primarily on our Manito pipeline.

- Foreign Exchange Impact Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. The average CAD to USD exchange rates for 2013 and 2012 were $1.03 CAD: $1.00 USD and $1.00 CAD: $1.00 USD, respectively. Therefore, revenues from our Canadian pipeline systems and trucking operations were unfavorably impacted by approximately $13 million for 2013 compared to 2012 due to the depreciation of the Canadian dollar relative to the U.S. dollar. The translation of revenues and expenses from our Canadian based subsidiaries did not have a significant impact on our Transportation segment results in 2012 as compared to 2011.

Additional noteworthy volume and revenue variances for the year ended December 31, 2013 compared to 2012 include (i) increased volumes and revenues on our All American pipeline due to higher production levels in 2013 coupled with lower maintenance activities at the production facilities in 2013 compared to 2012, (ii) decreases on the Salt Lake City Area Systems and our Line 63 and Line 2000 pipelines due to refinery maintenance issues and lower refinery demand for pipeline barrels; however, revenues on Line 63 pipeline were consistent with 2012 results due to movements on higher tariff segments, (iii) increased volumes and revenues on our Mid-Continent Area Systems primarily due the startup of the Mississippian Lime pipeline, which was placed in service in August 2013, (iv) increased trucking activity due to increased demand for production transported to rail terminals and hauls from pipeline disruptions and (v) decreased volumes and revenues on our Refined Products Pipelines primarily due to the sale of these assets in the third and fourth quarters of 2013.

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Additional noteworthy volume and revenue variances on our individual pipeline systems for the year ended December 31, 2012 include (i) increases on the Eagle Ford Area Systems resulting from the Gardendale Gathering System acquired in November 2011 and (ii) favorable volume and revenue variances in 2012 on our Rainbow pipeline due to downtime in 2011 as a result of a pipeline release in April of 2011 and rate increases in 2012, partially offset by the impact of a third-party competitor pipeline that was placed into service in the third quarter of 2011.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) increased during the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to (i) higher environmental response, remediation and related repair expenses associated with pipeline releases of approximately $21 million, (ii) higher integrity management expenses associated with smart pigging and other integrity work, (iii) higher payroll costs, primarily due to the BP NGL Acquisition and increased headcount and (iv) approximately $4 million of cost incurred associated with the testing of certain lines that we considered bringing back into service. Excluding the impacts of the environmental response and remediation expenses, field operating costs in general remained relatively consistent on a per barrel basis during the comparable annual periods.

Field operating costs (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2012 compared to the year ended December 31, 2011 consistent with the overall growth in segment volumes and remained relatively constant on a per barrel basis during each of those periods. Operating costs were also impacted by approximately $15 million of environmental remediation expenses associated with the Rangeland Pipeline release, which occurred in the second quarter of 2012, and approximately $11 million of environmental remediation expenses associated with the Rainbow Pipeline release, which occurred in the second quarter of 2011.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2013 over the year ended December 31, 2012 due to the continued overall growth of the segment and legal fees incurred in connection with the sale of certain of our refined products pipelines in 2013.

The increase in general and administrative expenses (excluding equity-indexed compensation expenses) during the year ended December 31, 2012 over the year ended December 31, 2011 was due to non-recurring costs associated with the closing and integration of the BP NGL Acquisition and ongoing administrative costs associated with this acquisition, as well as the continued overall growth of the segment.

Equity-Indexed Compensation Expenses. A majority of our equity-indexed compensation awards (including the AAP Management Units) contain performance conditions contingent upon PAA achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would have been if we had been accruing for these awards since the grant date. At December 31, 2013 and 2012, we determined that PAA distribution levels of $2.75 and $2.45 per unit, respectively, were probable of occurring. Furthermore, a change in PAA s unit price impacts the fair value of our liability-classified awards. See Note 15 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

On a consolidated basis, equity-indexed compensation expense increased by approximately $15 million for the year ended December 31, 2013 over the year ended December 31, 2012 primarily due to the following: (i) a more significant impact of the increase in PAA s unit price during the year ended December 31, 2013 compared to the impact of the increase during the year ended December 31, 2012, (ii) a greater number of units deemed probable of vesting for the year ended December 31, 2013 compared to the year ended December 31, 2012 and (iii) a higher average fair value per unit for those units deemed probable of vesting for the year ended December 31, 2013 compared to the year ended December 31, 2012. Equity-indexed compensation expense decreased by approximately $9 million for the year ended December 31, 2012 compared to the year ended December 31, 2011, primarily related to a less significant impact of the change in probability assessment as compared to 2011.

Equity Earnings in Unconsolidated Entities. The favorable variance in equity earnings in unconsolidated entities for the year ended December 31, 2013 compared to the year ended December 31, 2012 was largely due to (i) increased throughput on the Eagle Ford and White Cliffs pipelines as a result of increased production, as discussed above and (ii) increased capacity related to vessel additions and increased rates on services provided by Settoon Towing.

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Equity earnings in unconsolidated entities increased for the year ended December 31, 2012 compared to the year ended December 31, 2011 due to increased volumes as a result of industry fundamentals, as noted above.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The increase in maintenance capital in 2013 compared to 2012 and in 2012 compared to 2011 is primarily due to increased investments on pipeline integrity projects.

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 NGL, as well as NGL fractionation and isomerization services and natural gas and condensate processing 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:

	For the Year Ended December 31,			Favorable/(Unfavorable)			
Operating Results (1)				**2013-2012**		**2012-2011**	
(in millions, except per barrel amounts)	**2013**	**2012**	**2011**	**$**	**%**	**$**	**%**
Revenues	$ 1,075	$ 868	$ 605	$ 207	24%	$ 263	43%
Natural gas sales (2)	302	230	191	72	31%	39	20%
Storage related costs (natural gas related)	(16)	(22)	(22)	6	27%		%
Natural gas costs (2)	(296)	(216)	(183)	(80)	(37)%	(33)	(18)%
Field operating costs (excluding equity-indexed compensation expense)	(362)	(289)	(165)	(73)	(25)%	(124)	(75)%
Equity-indexed compensation expense - operations	(2)	(2)	(2)		%		%
Segment general and administrative expenses (3) (excluding equity-indexed compensation expense)	(63)	(64)	(47)	1	2%	(17)	(36)%
Equity-indexed compensation expense - general and administrative	(22)	(23)	(19)	1	4%	(4)	(21)%
Segment profit	$ 616	$ 482	$ 358	$ 134	28%	$ 124	35%
Maintenance capital	$ 38	$ 49	$ 22	$ 11	22%	$ (27)	(123)%
Segment profit per barrel	$ 0.43	$ 0.38	$ 0.36	$ 0.05	13%	$ 0.02	6%

	For the Year Ended December 31,			Favorable/(Unfavorable)			
				2013-2012		**2012-2011**	
Volumes (4) (5)	**2013**	**2012**	**2011**	**Volumes**	**%**	**Volumes**	**%**

Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	94	90	70	4	4%	20	29%
Rail load / unload volumes (average volumes in thousands of barrels per day)	221			221	N/A		N/A
Natural gas storage (average monthly capacity in billions of cubic feet)	96	84	71	12	14%	13	18%
NGL fractionation (average volumes in thousands of barrels per day)	96	79	14	17	22%	65	464%
Facilities segment total (average monthly volumes in millions of barrels)	120	106	82	14	13%	24	29%

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

(2) Natural gas sales and costs are primarily attributable to the activities performed by our natural gas storage commercial optimization group.

(3) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

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

(5) Facilities segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the year and divided by the number of months in the year; (iii) natural gas capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes multiplied by the number of days in the year and divided by the number of months in the year.

The following is a discussion of items impacting Facilities segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. As noted in the table above, our Facilities segment revenues, less storage related costs and natural gas costs, and volumes increased year-over-year for each comparative period presented. The significant variances in revenues and average monthly volumes between the comparative periods are primarily due to our ongoing acquisition and expansion activities as discussed below:

- Rail Terminal Acquisition and Related Expansion Projects The USD Rail Terminal Acquisition in December 2012 and rail-related internal growth projects completed during the latter portion of 2012 and 2013 expanded our rail loading and unloading fee-based activities. Rail load and unload activities contributed approximately $103 million and $22 million to the increase in total revenues for the years ended December 31, 2013 and 2012, respectively.

- NGL Storage, Fractionation and Gas Processing Activities We acquired NGL storage facilities, fractionation plants and related assets through the BP NGL Acquisition completed in April 2012. These assets contributed approximately $87 million of aggregate revenues for the year ended December 31, 2013 over the year ended December 31, 2012, primarily due to the benefit from a full period of ownership of these assets in 2013 (as we only owned the assets for nine months of 2012), as well as from physical processing gains recognized primarily at our NGL fractionation facilities.

For the year ended December 31, 2012, the BP NGL Acquisition assets contributed aggregate revenues of approximately $204 million, increased average monthly capacity of NGL storage by approximately 10 million barrels and increased average NGL fractionation throughput by approximately 65,000 barrels per day over the year ended December 31, 2011.

- Other Expansion Projects and Acquisitions We estimate that expansion projects that were completed in phases throughout recent years at some of our major terminal locations favorably impacted revenues by approximately $22 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Such projects included completed phases of expansions at our Cushing, Patoka, St. James and Yorktown terminals, new condensate stabilizers at our Gardendale site, and expansion of gas processing capacity at our facilities near the Gulf Coast. Partially offsetting the increased revenues from these expansions was reduced revenues from certain storage facilities in California and the East Coast due to decreased demand. While average monthly natural gas storage capacity increased during 2013 due to expansions of the Pine Prairie and Southern Pines facilities, decreased storage rates on contracts executed to replace expiring contracts on existing capacity largely offset incremental revenues from our natural gas storage activities.

The completion of our Yorktown facility acquisition in December 2011 and expansion projects at our Cushing, Patoka and St. James terminals throughout 2011 and 2012 resulted in increased storage capacity and barge loading and receipt capability. We estimate that these activities increased our revenues by approximately $24 million on a combined basis for the year ended December 31, 2012 compared to the year ended December 31, 2011. Additionally, revenues and volumes for 2012 compared to 2011 were favorably impacted by the expansion of working gas capacity at PNG s Pine Prairie and Southern Pines facilities by approximately 17 Bcf in the aggregate during 2012.

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Field Operating Costs. Field operating costs (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2013 compared to the year ended December 31, 2012 due to our growth through acquisitions, primarily the BP NGL and USD Rail Terminal Acquisitions. A portion of the increase was also related to additional costs for integrity and other maintenance, particularly on the assets that were part of the BP NGL Acquisition.

The increase in field operating costs (excluding equity-indexed compensation expenses) during the year ended December 31, 2012 over the year ended December 31, 2011 was also primarily due to growth through acquisitions, primarily the BP NGL and Yorktown acquisitions.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2012 compared to the year ended December 31, 2011 due to growth associated with the BP NGL Acquisition as well as certain one-time costs during 2012 associated with integrating this acquisition.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense increased during 2013 as compared to 2012 and decreased during 2012 as compared to 2011. See the discussion regarding such variances under Transportation Segment above. Also, see Note 15 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The decrease in maintenance capital in 2013 from 2012 is primarily due to two major equipment replacement projects that occurred in 2012. These projects contributed to the overall increase in 2012 from 2011, along with growth from acquisitions and increased integrity investment.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers. We do not anticipate that future changes in revenues resulting from variances in commodity prices will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchase volumes, NGL sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) 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.

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

	For the Year Ended			Favorable/(Unfavorable)			
Operating Results (1)		**December 31,**		**2013-2012**		**2012-2011**	
(in millions, except per barrel amounts)	**2013**	**2012**	**2011**	**$**	**%**	**$**	**%**

Revenues	$ 40,696	$ 36,440	$ 33,068	$ 4,256	12%	$ 3,372	10%
Purchases and related costs (2)	(39,315)	(35,139)	(31,984)	(4,176)	(12)%	(3,155)	(10)%
Field operating costs (excluding equity-indexed compensation expense)	(422)	(417)	(314)	(5)	(1)%	(103)	(33)%
Equity-indexed compensation expense - operations	(3)	(2)	(2)	(1)	(50)%		%
Segment general and administrative expenses (3) (excluding equity-indexed compensation expense)	(102)	(101)	(86)	(1)	(1)%	(15)	(17)%
Equity-indexed compensation expense - general and administrative	(32)	(28)	(35)	(4)	(14)%	7	20%
Segment profit	$ 822	$ 753	$ 647	$ 69	9%	$ 106	16%
Maintenance capital	$ 15	$ 13	$ 12	$ (2)	(15)%	$ (1)	(8)%
Segment profit per barrel	$ 2.09	$ 2.05	$ 2.05	$ 0.04	2%	$	%

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Average Daily Volumes (in thousands of barrels per day)	For the Year Ended December 31, 2013	2012	2011	Favorable (Unfavorable) 2013-2012 Volume	%	2012-2011 Volume	%
Crude oil lease gathering purchases	859	818	742	41	5%	76	10%
NGL sales	215	182	103	33	18%	79	77%
Waterborne cargos	4	3	21	1	33%	(18)	(86)%
Supply and Logistics segment total	1,078	1,003	866	75	7%	137	16%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged crude oil and NGL inventory) of approximately $30 million, $12 million and $20 million for the years ended December 31, 2013, 2012, and 2011, respectively.

(3) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

The NYMEX West Texas Intermediate benchmark price of crude oil ranged from approximately $87 to $111 per barrel, $77 to $111 per barrel, and $75 to $115 per barrel during 2013, 2012, and 2011, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for all periods presented, resulting from increases in volumes in the comparative 2013 and 2012 periods. The increase in 2012 over 2011 was further impacted by higher commodity prices.

Generally, we expect a base level of earnings from our Supply and Logistics segment from the assets employed by this segment. This base level 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. Also, our NGL marketing operations are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on NGL demand and thus our financial performance.

The following is a discussion of items impacting Supply and Logistics segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs and excluding gains and losses from derivative activities (see the Impact from Derivative Activities section below), increased year-over-year for each of the comparative periods presented. The following summarizes the more significant items in the comparative periods:

- NGL Marketing Operations Revenues from our NGL marketing operations increased during the year ended December 31, 2013 as compared to the year ended December 31, 2012, primarily due to more favorable market prices and higher demand related to (i) increases in export capacity in the U.S. that reduced overall product availability in the market, (ii) increased heating requirements during the extended winter season, (iii) heavy crop drying and (iv) petrochemical demand as well as more favorable supply contracts. Additionally, NGL margins during the 2012 period were negatively impacted by the sale of NGL product at points in time where spot prices were less than our weighted average inventory cost, primarily associated with inventory acquired in the BP NGL Acquisition on April 1, 2012. NGL sales volumes increased over the comparative year ended December 31, 2012 primarily due to increased demand as discussed above, as well as the impact from our BP NGL Acquisition.

- North American Crude Oil Production and Related Market Economics The increasing production of oil and liquids-rich gas in North America over the last several years generally created supply and demand imbalances that increased the volatility of historical differentials for various grades of crude oil and also impacted the historical pricing relationship between NGL and crude oil. Lack of existing pipeline takeaway capacity and associated logistical challenges in certain of these producing regions created market conditions and opportunities that were favorable to our supply and logistics activities. During 2012 and the first quarter of 2013, these conditions provided opportunities for increased

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margins. However, infrastructure additions in many of these resource plays during the second and third quarters of 2013 began to relieve certain of the transportation constraints that had created opportunities for these favorable crude oil margins. Therefore, although we experienced higher crude oil lease gathering volumes in 2013 compared to 2012, we experienced fewer opportunities to capture favorable differentials from market dislocations.

We believe the fundamentals of our business remain strong; however, as the midstream infrastructure in these producing regions continues to be developed, we believe a normalization of margins will continue to occur as the logistics challenges are addressed. (See Items 1 and 2 Business and Properties Description of Segments and Associated Assets Supply and Logistics Segment Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model included in Part I for further discussion regarding our business model, including diversification and utilization of our asset base among varying demand- and supply-driven markets.)

Impact from derivative activities. The mark-to-market valuation of our derivative activities impacted our net revenues as shown in the table below (in millions):

	For the Twelve Months Ended December 31,			Variance	
	2013	**2012**	**2011**	**2013-2012**	**2012-2011**
Gains/(losses) from derivative activities(1)	$ (59)	$ (75)	$ 62	$ 16	$ (137)

(1) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. These amounts are reduced by the net impact of inventory valuation adjustments attributable to inventory hedged by the related derivative and gains recognized in later periods on physical sales of inventory that was previously written down. See Note 11 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

Field Operating Costs. The increase in field operating costs (excluding equity-indexed compensation expenses) for the year ended December 31, 2012 over the year ended December 31, 2011 was primarily related to increased lease gathering volumes, particularly in West Texas, Oklahoma and the Rockies, which required the use of higher cost, third-party transporters to supplement our truck fleet.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense increased during 2013 as compared to 2012 and decreased during 2012 as compared to 2011. See the discussion regarding such variances under Transportation Segment above. Also, see Note 15 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $378 million for the year ended December 31, 2013 compared to $483 million and $250 million for the years ended December 31, 2012 and 2011. Such amounts include losses on impairments of long-lived assets of approximately $20 million, $168 million and $5 million, for the 2013, 2012 and 2011 periods, respectively. The impairments recognized in 2013 and 2011 were predominantly related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and, in some instances, we utilized other assets to handle these activities. The impairments recognized in 2012 primarily related to our Pier 400 terminal project and the anticipated sale of certain refined products pipeline systems and related assets, which occurred in 2013. See Note 6 to our Consolidated Financial Statements for further discussion of asset impairments.

Excluding the impact of asset impairments, depreciation and amortization expense increased during the 2013 period over the comparable 2012 period primarily due to an increased amount of assets resulting from acquisition activities, as well as various internal growth projects completed in recent years.

Excluding the impact of asset impairments, the remaining increase for the 2012 as compared to the 2011 period was primarily the result of an increased amount of assets resulting from acquisition activities, including accelerated amortization of certain intangible assets associated with our BP NGL Acquisition, as well as the completion of various internal growth projects. Such increases were partially offset by a decrease in expense of $13 million resulting from extensions of depreciable lives of several of our crude oil and other storage facilities and pipeline systems, as well as a net gain of approximately $6 million recognized upon disposition of certain assets.

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Interest Expense

Interest expense increased by approximately $14 million and $36 million for the years ended December 31, 2013 and 2012, respectively, over the previous year. 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 the components impacting the interest expense variance for the years ended December 31, 2013 and 2012 (in millions, except for percentages):

			Average LIBOR Rate	Weighted Average Interest Rate (1)
Interest expense for the year ended December 31, 2011	$	259	0.2%	5.5%
Impact of retirement of senior notes (2) (4)		(8)		
Impact of issuance of senior notes (3) (5)		44		
Impact of capitalized interest		(11)		
Impact of credit facilities		(3)		
Impact of interest included in purchases and other costs (8)		8		
Other		6		
Interest expense for the year ended December 31, 2012	$	295	0.2%	5.2%
Impact of retirement of senior notes (4) (7)		(15)		
Impact of issuance of senior notes (5) (6)		47		
Impact of ineffective portion of terminated forward-starting swaps		(4)		
Impact of credit facilities and commercial paper program		18		
Impact of interest included in purchases and other costs (8)		(18)		
Other		(14)		
Interest expense for the year ended December 31, 2013	$	309	0.2%	4.4%

(1) Excludes commitment and other fees.

(2) In February 2011, PAA redeemed its outstanding $200 million, 7.75% senior notes due 2012.

(3) In January 2011, PAA completed the issuance of $600 million of 5.00% senior notes due 2021.

(4) In September 2012, PAA s $500 million, 4.25% senior notes matured.

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(5) In March 2012, PAA completed the issuance of $750 million of 3.65% senior notes due 2022 and $500 million of 5.15% senior notes due 2042, and in December 2012, PAA completed the issuance of $400 million of 2.85% senior notes due 2023 and $350 million of 4.30% senior notes due 2043.

(6) In August 2013, PAA completed the issuance of $700 million of 3.85% senior notes due 2023.

(7) In December 2013, PAA s $250 million, 5.63% senior notes matured.

(8) Interest costs attributable to borrowings for hedged crude oil and NGL inventory 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 costs were approximately $30 million, $12 million and $20 million for the years ended December 31, 2013, 2012, and 2011, respectively.

Other Income/(Expense), Net

Other income/(expense), net in each of the years ended December 31, 2013 and 2012 was primarily impacted by foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with intercompany notes and the impact of related foreign currency hedges.

In addition to the impact of such foreign currency gains, the 2011 period also included a loss of approximately $23 million that was recognized in conjunction with the early redemption of PAA s $200 million, 7.75% senior notes in February 2011.

Income Tax Expense

Income tax expense increased for year ended December 31, 2013 compared to the year ended December 31, 2012 primarily as a result of stronger performance from our existing Canadian operations and our operations related to the BP NGL Acquisition, both of which increased the proportion of earnings subject to Canadian federal and provincial taxes.

Income tax expense increased for the year ended December 31, 2012 compared to the year ended December 31, 2011, even with a slight decrease in the combined Canadian federal and provincial rates for 2012, primarily as a result of the BP NGL Acquisition which increased the proportion of earnings subject to Canadian federal and provincial taxes. Canadian withholding taxes also increased on interest and dividends from our Canadian entities to other affiliates. These Canadian withholding taxes are due as payments occur.

Outlook

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays occurring contemporaneously with attractive crude oil and liquids prices, U.S. crude oil and liquids production has increased rapidly in multiple regions in the lower 48 states. This is particularly true for light crudes and condensates. As a result of similar resource development activities in Canada and ongoing oil sands development activities, Canadian crude oil production has also increased. A significant portion of these activities and production increases are concentrated in areas where we have a significant asset presence, increasing the utilization of our existing assets as well as providing multiple opportunities to expand and extend our asset base as well as the services we provide our customers throughout the value chain.

Additionally, the crude oil market has periodically experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude qualities, international supply issues, and regional downstream operating issues. During 2012 and 2013, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment. As a result of the factors enumerated above we believe current U.S. and Canadian energy industry fundamentals are favorable for our asset base and business model.

However, despite the prevailing outlook for steady growth in U.S. and Canadian crude oil production and the continuing opportunity to displace waterborne foreign crude imports to balance the North American market, we believe global oil and petroleum products supply and demand balances are such that the potential exists for a disruption that leads to lower than forecasted rates of growth in North American crude oil production. Potential disruption catalysts include a meaningful decrease in crude oil prices and/or capital availability coupled with an overall increase in cost of capital. Accordingly, there can be no assurance that North American production increases will continue unabated or that we will not be negatively impacted by potential volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely continue to reduce existing infrastructure constraints, which could place downward pressure on unit margins in our various segments, and we cannot be certain that our expansion efforts will generate targeted returns or that any future acquisition activities will be successful. See Item 1A. Risk Factors - Risks Related to PAA s Business.

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Liquidity and Capital Resources

General

On a consolidated basis, our primary sources of liquidity are (i) cash flow from operating activities as further discussed below in the section entitled Cash Flow from Operating Activities, (ii) borrowings under credit facilities or the PAA commercial paper program and (iii) funds received from PAA s sales of equity and debt securities. Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses and interest payments on outstanding debt, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on long-term debt and (v) distributions to our Class A shareholders and noncontrolling interests. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under credit facilities or the PAA commercial paper program. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs, and/or the issuance of additional PAA equity or debt securities. As of December 31, 2013, we had a working capital deficit of approximately $448 million and approximately $1.95 billion of liquidity available to meet our ongoing operating, investing and financing needs as noted below (in millions):

		As of December 31, 2013
Availability under PAA senior unsecured revolving credit facility, prior to giving effect to PAA commercial paper program (1)	$	1,587
Availability under PAA senior secured hedged inventory facility, prior to giving effect to PAA commercial paper program (1)		1,372
Less: Amounts outstanding under the PAA commercial paper program		(1,109)
Subtotal		1,850
Availability under AAP senior secured revolving credit facility		60
Cash and cash equivalents		43
Total	$	1,953

(1) Borrowings under the PAA commercial paper program reduce available capacity under the facility.

We believe that we have and will continue to have the ability to access the credit facilities and PAA commercial paper program, 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 materially 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 and PAA commercial paper program is subject to ongoing compliance with covenants. As of December 31, 2013, AAP and PAA were in compliance with all such covenants.

Cash Flow from Operating Activities

The primary drivers of cash flow from operating activities are (i) the collection of amounts related to the sale of crude oil, NGL and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services provided for a fee and (ii) the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses, principally field operating costs, general and administrative expenses and interest expense.

Cash flow from operating activities can be materially impacted by 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. In the month we pay for the stored crude oil, we borrow under the credit facilities or PAA commercial paper program (or use cash on hand) to pay for the crude oil, which negatively impacts 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, the level of NGL 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 credit facilities or the PAA commercial paper program 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 credit facilities or the PAA commercial paper program to pay for the inventory or linefill. In addition, cash flow from operating activities 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.

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Net cash provided by operating activities for the year ended December 31, 2013 was approximately $1.95 billion, primarily resulting from earnings from our operations. Additionally, during 2013, we decreased the amount of our inventory, primarily due to the sale of crude oil inventory that had been stored during the contango market, as well as the sale of NGL inventory due to end users increased demand for product used for heating and crop drying during the latter half of 2013. The net proceeds received from liquidation of such inventory during the year were used to repay borrowings under credit facilities or the PAA commercial paper program and favorably impacted cash flow from operating activities. These decreases in inventory were partially offset by an increase in natural gas inventory whereby we retained more capacity for our own use. We primarily used borrowings under credit facilities to pay for the stored natural gas, which negatively impacted our cash flow from operating activities. Also, a significant portion of our 2013 natural gas sales occurred in December 2013, with cash collections on these sales occurring in January 2014.

Net cash provided by operating activities for the twelve months ended December 31, 2012 was approximately $1.23 billion. The cash provided by operating activities reflects cash generated by our recurring operations, and is also significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage as discussed above. During 2012, we increased the amount of our crude oil inventory, which was primarily financed through borrowings under credit facilities as well as through PAA s $250 million senior notes that are currently classified as Short-term debt on our Consolidated Balance Sheet. This resulted in a negative impact on our cash flow from operating activities for the period. During the year, we also increased the amount of our NGL inventory; however, these volumetric increases were offset by lower prices for such inventory stored at the end of the year compared to prior year amounts.

Net cash provided by operating activities for the twelve months ended December 31, 2011 was approximately $2.36 billion. During 2011, we reduced our overall inventory levels resulting in a positive impact to operating cash flow. The reduction in our crude oil inventory levels was primarily due to liquidating a certain amount of inventory that had been stored in the contango market, which primarily began liquidating during the latter portion of the second quarter of 2011, as well as liquidating the inventory stored through our waterborne cargo purchase activity, which occurred throughout the third and fourth quarters of 2011.

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Credit Agreements, PAA Commercial Paper Program and Indentures

PAA has three primary credit arrangements. These include a $1.6 billion senior unsecured revolving credit facility maturing in 2018 and a $1.4 billion senior secured hedged inventory facility maturing in 2016. Additionally, PAA has a $1.5 billion unsecured commercial paper program that is backstopped by its revolving credit facility and hedged inventory facility. The PAA credit agreements (which impact the ability to access the PAA commercial paper program) and the indentures governing PAA s senior notes contain cross-default provisions. A default under PAA s credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as PAA is in compliance with the provisions in its credit agreements, PAA s ability to make distributions of available cash is not restricted. PAA is in compliance with the covenants contained in its credit agreements and indentures as of December 31, 2013. In addition, AAP has a credit agreement which includes a $500 million term loan facility and a $75 million senior secured revolving credit facility. AAP is in compliance with the covenants contained in its credit agreement as of December 31, 2013. See Note 9 to our Consolidated Financial Statements for additional discussion regarding credit agreements, the PAA commercial paper program and long-term debt.

Equity and Debt Financing Activities

On a consolidated basis, our financing activities primarily relate to funding acquisitions and internal capital projects, and short-term working capital and hedged inventory borrowings related to our NGL business and contango market activities, as well as the refinancing of debt maturities. Our financing activities have primarily consisted of PAA equity offerings, PAA senior notes offerings and borrowings and repayments under the credit facilities.

PAA Registration Statements. PAA periodically accesses the capital markets for both equity and debt financing. PAA has filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows PAA to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). At December 31, 2013, PAA had approximately $1.5 billion of unsold securities available under the Traditional Shelf. PAA also has access to a universal shelf registration statement (WKSI Shelf), which provides it with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and capital needs.

PAA Equity Offerings. The following table summarizes the issuance of PAA s common units in connection with marketed equity offerings or PAA s Continuous Offering Program during the three years ended December 31, 2013 (net proceeds in millions):

Year	Type of Offering	PAA Common Units Issued		Net Proceeds (1)
2013	Continuous Offering Program	8,644,807	$	468(2)
2013 Total		**8,644,807**	**$**	**468**
2012	Continuous Offering Program	12,063,707	$	513(2)
2012	Marketed Offerings	11,500,000		446(3)
2012 Total		**23,563,707**	**$**	**959**
2011	Marketed Offerings	27,870,000	$	870(3)
2011 Total		**27,870,000**	**$**	**870**

(1) Amounts do not include PAA s general partner s proportionate capital contributions. Amounts are net of costs associated with the offerings.

(2) PAA pays commissions to its sales agents in connection with common unit issuances under its Continuous Offering Program. PAA paid approximately $5 million and $6 million of such commissions during 2013 and 2012, respectively. The net proceeds from these offerings were used for general partnership purposes.

(3) These offerings of PAA s common units were underwritten transactions that required PAA to pay a gross spread. The net proceeds from these offerings were used to reduce outstanding borrowings under PAA s credit facilities and for general partnership purposes.

PAA Senior Notes Offerings. During the last three years PAA issued senior unsecured notes as summarized in the table below (in millions):

Year	Description	Maturity	Face Value	Net Proceeds(1)
2013	3.85% Senior Notes issued at 99.792% of face value (2)	October 2023	$ 700	$ 699
2012	2.85% Senior Notes issued at 99.752% of face value (2)	January 2023	$ 400	$ 399
2012	4.30% Senior Notes issued at 99.925% of face value (2)	January 2043	$ 350	$ 350
2012	3.65% Senior Notes issued at 99.823% of face value (3)	June 2022	$ 750	$ 748
2012	5.15% Senior Notes issued at 99.755% of face value (3)	June 2042	$ 500	$ 499
2011	5.00% Senior Notes issued at 99.521% of face value (4)	February 2021	$ 600	$ 597

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

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(2) PAA used the net proceeds from this offering to repay outstanding borrowings under its credit facilities or commercial paper program and for general partnership purposes.

(3) PAA used the net proceeds from this offering to repay outstanding borrowings under its credit facilities and for general partnership purposes. In addition, PAA used a portion of the proceeds to prefund the BP NGL Acquisition. See Note 3 to our Consolidated Financial Statements for a discussion of the BP NGL Acquisition.

(4) PAA used the net proceeds from this offering to repay outstanding borrowings under its credit facilities and for general partnership purposes. In addition, PAA used a portion of the proceeds to redeem all of its outstanding $200 million, 7.75% senior notes due 2012, as discussed further below.

In December 2013, PAA s $250 million, 5.63% senior notes matured and were repaid with proceeds from the PAA commercial paper program. In September 2012, PAA s $500 million, 4.25% senior notes matured and were repaid with proceeds from its credit facilities.

In February 2011, PAA s $200 million, 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million. PAA utilized cash on hand and available capacity under its credit facilities to redeem these notes.

Acquisitions and Capital Expenditures and Distributions Paid to Our Class A Shareholders and Noncontrolling Interests

In addition to operating needs discussed above, on a consolidated basis, we also use cash for acquisition activities, internal growth projects and distributions paid to our Class A shareholders and noncontrolling interests. 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 of 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.

2014 Capital Expansion Projects. We expect the majority of funding for our 2014 capital program will be provided by borrowings under PAA s revolving credit facility or commercial paper program and cash flow in excess of partnership distributions as well as through PAA s access to the capital markets for equity and debt as deemed necessary. Our 2014 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects	**2014**
Permian Basin Area Projects	$430
Cactus Pipeline	310
Rail Terminal Projects (1)	185
Ft. Sask Facility Projects / NGL Pipeline	180
Eagle Ford JV Project	60
Western Oklahoma Extension	50
Mississippian Lime Pipeline	45
White Cliffs Expansion	40
Line 63 Reactivation	35
Gardendale Fractionator and Stabilizer	35
Natural Gas Storage (Multiple Projects)	25
Other Projects	305
	$1,700
Potential Adjustments for Timing/Scope Refinement (2)	-$100 + $100
Total Projected Expansion Capital Expenditures	$1,600 - $1,800

(1) Includes projects located in or near Bakersfield, CA, Carr, Co, Van Hook, ND and Western Canada.

(2) Potential variation to current capital costs estimates may result from changes to project design, final cost of materials and labor and timing of incurrence of costs due to uncontrollable factors such as permits, regulatory approvals and weather.

Distributions to our Class A shareholders. We distribute 100% of our available cash within 55 days after the end of each quarter to Class A shareholders of record. 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 14, 2014, we paid a quarterly distribution of $0.12505 per Class A share, which was prorated for the partial quarter following the closing of our IPO on October 21, 2013. This distribution corresponds to a distribution of $0.15979 per Class A share ($0.63914 per Class A share on an annualized basis) before proration, assuming our ownership of AAP for the full fourth quarter of 2013. See Note 10 to our Consolidated Financial Statements for details of distributions paid. Also, see Item 5. Market for Registrant s Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities-Cash Distribution Policy for additional discussion on distributions.

Distributions Prior to our IPO. Prior to the completion of our IPO in October 2013, we distributed $6 million to the members of GP LLC during 2013. Of this amount, approximately $3 million relates to distributions received from AAP related to the net proceeds from the increase in AAP s term loan. See Note 9 to the Consolidated Financial Statements for further discussion. During the years ended December 31, 2012 and 2011, $3 million and $2 million, respectively, were distributed to the members of GP LLC.

Distributions to noncontrolling interests. Distributions to noncontrolling interests represent amounts paid on interests in consolidated entities that are not owned by us. During the years ended December 31, 2013, 2012 and 2011, we paid distributions of approximately $1.5 billion, $1.0 billion and $822 million, respectively, to noncontrolling interests. Of the amount distributed during the year ended December 31, 2013, approximately $296 million relates to distributions paid for the noncontrolling interests proportionate share of the net proceeds from the increase in AAP s term loan. See Note 10 to the Consolidated Financial Statements for further discussion.

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

Distribution of Net Proceeds of our IPO. In October 2013, we completed our IPO of 132,382,094 Class A shares representing limited partner interests at a price of $22.00 per Class A share, generating net proceeds, after deducting underwriting discounts and commissions and direct offering expenses, of approximately $2.8 billion. We distributed these net proceeds to certain owners of AAP who, prior to our IPO, sold a portion of their interests in AAP to us in exchange for the right to receive an amount equal to the net proceeds of the IPO.

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Contingencies

For a discussion of contingencies that may impact us, see Note 16 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years with a limited number of contracts extending up to approximately ten 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. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. 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 entities that we deem creditworthy or who have provided credit support we consider adequate.

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, 2013 (in millions):

	2014	2015	2016	2017	2018	2019 and Thereafter	Total
Long-term debt, including related interest payments (1)	$ 361	$ 904	$ 510	$ 705	$ 1,390	$ 7,350	$ 11,220
Leases (2)	152	132	124	103	78	386	975
Other obligations (3)	216	80	46	32	21	140	535
Subtotal	729	1,116	680	840	1,489	7,876	12,730
Crude oil, natural gas, NGL and other purchases (4)	9,952	4,560	4,341	3,634	2,389	7,503	32,379
Total	$ 10,681	$ 5,676	$ 5,021	$ 4,474	$ 3,878	$ 15,379	$ 45,109

(1) Includes debt service payments, interest payments due on PAA s senior notes, interest payments on long-term borrowings outstanding under the AAP credit agreement and the commitment fee on assumed available capacity under the PAA revolving credit facilities. Although there may be short-term borrowings on the PAA revolving credit facilities, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the facilities) in the amounts above.

(2) Leases are primarily for (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars.

(3) Includes (i) other long-term liabilities, (ii) storage and transportation agreements and (iii) commitments related to capital expansion projects, including projected contributions for our share of the capital spending of our equity-method investments. Excludes a non-current liability of approximately $1 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2013. 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 supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs and construction activities. At December 31, 2013 and 2012, we had outstanding letters of credit of approximately $41 million and $24 million, respectively.

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Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

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, 2013 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Settoon Towing, LLC	Barge Transportation Services	50%	$ 315	$	$ 230
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%	$ 425	$ 9	$
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%	$ 449	$ 85	$
Frontier Pipeline Company	Crude Oil Pipeline	22%	$ 25	$ 3	$
Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 26	$ 6	$

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

We are exposed to various market risks, including (i) commodity price risk, (ii) interest rate risk and (iii) currency exchange rate risk. We use various derivative instruments to manage such risks and, in certain circumstances, to realize incremental margin during volatile market conditions. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our exchange-cleared and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

We use derivative instruments to hedge commodity price risk associated with the following commodities:

- *Crude oil and refined products*

We utilize crude oil and refined products derivatives to hedge commodity price risk inherent in our Supply and Logistics and Transportation segments. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory, and storage capacity utilization. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

- *Natural gas*

We utilize natural gas derivatives to hedge commodity price risk inherent in our Supply and Logistics and Facilities segments. Our objectives for these derivatives include hedging anticipated purchases and sales and managing our anticipated base gas requirements. We manage these exposures with various instruments including exchange-traded futures, swaps and options.

- *NGL*

We utilize NGL derivatives, primarily butane and propane derivatives, to hedge commodity price risk inherent in our Supply and Logistics segment. Our objectives for these derivatives include hedging anticipated purchases and sales. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

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See Note 11 to our Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

Our policy is to (i) purchase only product for which we have a market, (ii) hedge our purchase and sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or other derivative instruments for the purpose of speculating on outright commodity price changes, as these activities could expose us to significant losses.

The fair value of our commodity derivatives and the change in fair value as of December 31, 2013 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil and related products	$ 24	$ 8	$ (4)
Natural gas	(20)	$ (9)	$ 9
NGL and other	(50)	$ (23)	$ 23
Total fair value	$ (46)		

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or 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 commodity 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

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time we use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. The majority of our variable rate debt at December 31, 2013, approximately $1.6 billion, is subject to interest rate re-sets, which range from one week to three months. The average interest rate of approximately 1.5% is based upon rates in effect during the year ended December 31, 2013. The fair value of our interest rate derivatives is an asset of approximately $26 million as of December 31, 2013. A 10% increase in the forward LIBOR curve as of December 31, 2013 would result in an increase of approximately $19 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2013 would result in a decrease of approximately $19 million to the fair value of our interest rate derivatives. See Note 11 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives is a liability of approximately $4 million as of December 31, 2013. A 10% increase in the exchange rate (USD-to-CAD) would result in a decrease of approximately $27 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would result in an increase of approximately $28 million to the fair value of our foreign currency derivatives. See Note 11 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***

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our DCP. Our DCP is designed to ensure that information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the Exchange Act) is (i) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

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

Internal Control over Financial Reporting

This annual report does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

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.

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

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2013 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*

Our Management and Governance

Immediately prior to completion of our initial public offering in October 2013, certain owners of Plains AAP, L.P. (AAP) sold a portion of their interests in AAP to us, resulting in our ownership of a limited partnership interest in AAP. As of December 31, 2013, we owned a 22.1% limited partner interest in AAP, and the remaining limited partner interests in AAP continue to be held by the owners of AAP immediately prior to our initial public offering (the Legacy Owners). AAP directly owns all of the incentive distribution rights and indirectly owns the 2% general partner interest in Plains All American Pipeline, L.P. (PAA). AAP is the sole member of PAA GP LLC, which is the general partner of PAA. Also, through a series of transactions prior to our initial public offering with our general partner and the owners of Plains All American GP LLC (GP LLC), GP LLC s general partner interest in AAP became a non-economic interest, and we became the owner of a 100% managing member interest in GP LLC.

Our general partner, PAA GP Holdings LLC, manages our operations and activities. Class A shareholders are limited partners and do not participate in the management of our operations. 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.

We and our general partner have no employees. All of our officers and other personnel necessary for our business to function (to the extent not out-sourced) are employed by GP LLC. As a result, the Administrative Agreement (described below under Item 13. Certain Relationships and Related Transactions, and Director Independence Related Party Transactions Administrative Agreement) provides for AAP s payment of an annual fee to GP LLC for general and administrative services. The initial fee is $1.5 million per year and is subject to adjustment on an annual basis, beginning on January 1, 2015, based on the Consumer Price Index. The fee is also subject to adjustment if a material event occurs that impacts the general and administrative services provided to us such as acquisitions, entering into new lines of business or changes in laws, regulations, listing requirements or accounting rules. In addition to the general and administrative services provided to us by GP LLC, we also expect to incur direct annual expenses of approximately $1.5 million per year for recurring costs associated with being a separate publicly traded entity, including expenses associated with (i) compensation for new directors, (ii) incremental director and officer liability insurance, (iii) listing on the NYSE, (iv) investor relations, (v) legal, (vi) tax and (vii) accounting. All of these direct expenses, to the extent such expenses and expenditures exceed or are in addition to those contemplated in the above fee, other than income taxes payable by us, are borne by AAP. All of the officers and a majority of the directors of our general partner are also officers or directors of GP LLC. Our general partner s executive officers spend the substantial majority of their time managing the business of PAA, which benefits us as PAA s performance will determine our success. We estimate that these officers will spend less than 10% of their time on our business, as distinct from PAA s business. The actual time devoted by these officers to managing our business as well as PAA s will fluctuate as a result of the relative activity level between the two entities. The amount of incremental time spent by non-officer directors who serve on both boards will depend to some extent on committee assignments, but our general partner estimates that such directors will spend less than 20% more time by serving on the board of directors of our general partner. One of our independent directors also serves as an independent director of GP LLC.

In addition to the fee and expenses described above, AAP reimburses GP LLC for expenses incurred (i) on our behalf; (ii) on behalf of our general partner; or (iii) for any other purpose related to our business and activities or those of our general partner. AAP also reimburses our general partner for any additional expenses incurred on our behalf or to maintain our legal existence and good standing. There is no limit on the amount of fees and expenses AAP may be required to pay to affiliates of our general partner on our behalf pursuant to the Administrative Agreement.

Election of Directors

Initial Election of Directors. Our general partner s limited liability company agreement provides for a board of directors consisting of seven members. For so long as each of EMG Investment, LLC (an affiliate of The

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Energy & Minerals Group), KAFU Holdings, L.P. (an affiliate of Kayne Anderson Investment Management Inc.) and Oxy Holding Company (Pipeline), Inc. (a subsidiary of Occidental Petroleum Corporation), together with their respective affiliates, which we refer to as the original designating parties, own at least a 10% limited partner interest in AAP (excluding for this purpose the AAP Management Units but including any indirect ownership interest in AAP through ownership of Class A shares), such party will be entitled to designate one director to our general partner s board of directors. In addition, any other person or group that acquires and maintains a 20% or greater limited partner interest in AAP, which we refer to a subsequent designating person, will be entitled to designate one director to our general partner s board of directors. We refer to this 10% ownership interest requirement for the original designating parties and this 20% ownership interest requirement for a subsequent designating person as the minimum ownership requirement, and we refer to the original designating parties and a subsequent designating person collectively as the designating parties. In no event will more than three designating parties be entitled to designate a director to our general partner s board of directors at any point in time. In the event that any designating party s ownership level falls below the minimum ownership requirement, such party will automatically forfeit its designation right, and the director then designated by such party will be replaced by a director elected by (i) a majority vote of the remaining directors if such forfeiture takes place prior to the date that the overall direct and indirect economic interest of the Legacy Owners and their permitted transferees in AAP falls below 40% (calculated as described below), which we refer to as the trigger date, and (ii) our Class A and Class B shareholders voting together as a single class if such forfeiture takes place after the trigger date. The 40% threshold referred to above will be calculated on a fully diluted basis that takes into account any Class A shares owned by the Legacy Owners and their affiliates and permitted transferees, assumes the exchange of all AAP Management Units for AAP units based on the applicable conversion factor and attributes the ownership of such AAP units to the Legacy Owners.

The limited liability company agreement of our general partner further provides that the Chief Executive Officer of our general partner will serve as a director and Chairman of the Board of our general partner. All three of the remaining members of our general partner s board of directors must be independent (as defined in applicable NYSE and SEC rules) and eligible to serve on the audit committee. Because we are a limited partnership, the listing standards of the NYSE do not require that our general partner s board of directors include a majority of independent directors. At least two directors on our general partner s board of directors must meet the criteria for service on a conflicts committee in accordance with our partnership agreement. Any successors to the three independent directors will be elected by our general partner s board of directors (rather than the members of our general partner), until such time as our shareholders are entitled to vote in the election of directors as described below.

Election of Directors Following Substantial Reduction in Legacy Owners Ownership. Our general partner s limited liability company agreement contains provisions linking the ownership of the membership interests in our general partner to the ownership of the outstanding AAP units. Membership interests in our general partner cannot be transferred without transferring the same number of AAP units and vice versa. The membership interests in our general partner generally may not be transferred in private (non-exchange) transactions other than in the case of specified permitted transfers. Any other transfers would be subject to a right of first refusal in favor of the other owners of our general partner, including us or our designee.

Our general partner s limited liability company agreement provides that as the Legacy Owners reduce their ownership in AAP (through their exchange of AAP units and Class B shares for Class A shares), they will be contractually obligated to contribute to us a percentage of membership interests in our general partner that corresponds to the percentage of AAP units being exchanged by such Legacy Owner. As a result, as the Legacy Owners reduce their ownership of AAP units and membership interests in our general partner, our ownership of our general partner will increase in the same proportion. Moreover, as a result of these provisions, holders of our Class A shares will not have the ability to acquire the contractual right to designate a director through the acquisition of Class A shares in market purchases. Following the trigger date, the following governance arrangements will occur: (i) within a certain period of time, our general partner s board of directors will be staggered into three classes; (ii) within a certain time period and subject to certain limitations, our Class A and Class B shareholders, voting together as a single class, will have the right to elect certain of our directors; and (iii) any person that owns of record at least 10% of our combined Class A and Class B shares will be entitled to nominate a single director for election at an annual meeting.

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Our Board Committees

Because we are a limited partnership, the listing standards of the NYSE do not require that we establish or maintain a nominating or compensation committee of the board. 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.

To be considered independent under NYSE listing standards, 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 of our general partner has determined that Messrs. Burk, Goyanes and Shackouls are independent under applicable NYSE rules.

Audit Committee. 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 of our general partner has determined that each member of our audit committee (Messrs. Burk, Goyanes and Shackouls) is independent under applicable NYSE rules and that Messrs. Burk and Goyanes are each an Audit Committee Financial Expert, as that term is defined in Item 407 of Regulation S-K.

None of the members of our audit committee has any relationships with us or our general partner, other than as a director and shareholder. Mr. Goyanes also serves as a director and chairman of the audit committee of the board of directors of GP LLC. For additional information regarding the experience and qualifications of our directors, please read the biographical descriptions under Directors and Executive Officers of our General Partner below.

Other Committees. Applicable NYSE listing standards do not require that we or our general partner have a compensation committee or a nominating committee. Our general partner s board of directors performs the functions of a compensation committee and administers our Long-Term Incentive Plan. Our general partner s board of directors did not retain any compensation consultants during 2013.

Our partnership agreement provides for the establishment 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 or between us and PAA or its affiliates. Such a committee would consist of a minimum of two members, none of whom can be officers or employees of our general partner or directors, officers or employees of its affiliates and each of whom must meet the independence standards established by the NYSE and the SEC for service on an audit committee. 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 shareholders. See Item 13. Certain Relationships and Related Transactions, and Director Independence Review, Approval or Ratification of Transactions with Related Persons.

Board Leadership Structure and Role in Risk Oversight

Our CEO also serves as Chairman of the Board. The board of directors of our general partner has no policy with respect to the separation of the offices of chairman and CEO; rather, that relationship is currently defined and governed by our general partner s limited liability company agreement, which currently requires coincidence of the offices. However, pursuant to the terms of our general partner s limited liability company agreement, if and when our general partner s board of directors elects a successor to our current CEO, by majority vote our general partner s board of directors may determine to separate the offices of CEO and Chairman of the Board. We do not have a lead independent director.

The management of enterprise-level risk (ELR) may be defined as the process of identifying, managing and monitoring events that present opportunities and risks with respect to creation of value for our Class A shareholders. The GP LLC board has delegated to PAA management the primary responsibility for ELR management, while the GP LLC board has retained responsibility for oversight of management in that regard. Management provides an ELR assessment to the GP LLC board at least once every year.

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Non-Management Executive Sessions and Shareholder Communications

NYSE listing standards require regular executive sessions of the non-management directors of a listed company, and an executive session for independent directors at least once a year. Only the members of our audit committee qualify as independent. We expect that our audit committee will routinely hold discussions with no other directors or members of management present. We also expect that our non-management directors will meet in executive session in connection with each regular board meeting, which will be held in conjunction with meetings of the board of directors of GP LLC. 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 Vice President of Internal Audit at Plains GP Holdings, 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.

Meetings and Other Information

Since the closing of our initial public offering in October 2013 through December 2013, our board of directors held no meetings, but approved various matters by unanimous written consent. Our audit committee held one meeting.

As discussed above, our general partner manages our operations and activities under the direction of our board of directors, whose members are currently either designated or appointed by members of our general partner. Accordingly, our Class A shareholders have only limited voting rights on matters affecting our business or governance. As a result, we will not hold regular annual meetings of shareholders for the purpose of electing directors or soliciting approval of any other routine matters prior to the trigger date.

Our audit committee charter 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 under the Structure and Governance tab in the Investor Relations section of our Internet website at *http://www.plainsallamerican.com*. 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.

Audit Committee Report

The audit committee of our general partner s board of directors 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 Public Company Accounting Oversight Board Auditing Standard No. 16, Communications with Audit Committees. 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.

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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, 2013 for filing with the SEC.

Everardo Goyanes, *Chairman*
Victor Burk
Bobby S. Shackouls

Directors and Executive Officers of Our General Partner

The following table sets forth certain information with respect to the directors and executive officers (for purposes of Item 401(b) of Regulation S-K) of our general partner. Directors are elected annually and all executive officers are appointed by the board of directors of our general partner. There is no family relationship between any executive officer and director. As discussed above, three of the owners of membership interests in our general partner each have the right to separately designate a member of our board of directors, and such designee in turn automatically becomes a member of the GP LLC board (as does the CEO). For additional information regarding the contractual designation of directors to our general partner s board, please read Election of Directors above.

Name	**Age (as of 12/31/13)**	**Position**(1)
Greg L. Armstrong(2)	55	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis	56	President and Chief Operating Officer
Mark J. Gorman	59	Executive Vice President Operations and Business Development
Phillip D. Kramer	57	Executive Vice President
Richard K. McGee	52	Executive Vice President, General Counsel and Secretary
John R. Rutherford	53	Executive Vice President
Al Swanson	49	Executive Vice President and Chief Financial Officer
John P. vonBerg	59	Executive Vice President Commercial Activities
W. David Duckett	58	President, Plains Midstream Canada
Chris Herbold	41	Vice President Accounting and Chief Accounting Officer
Victor Burk	64	Director and Member of Audit Committee
Everardo Goyanes(2)	69	Director and Member of Audit Committee*
John T. Raymond(2)	43	Director
Bobby S. Shackouls	63	Director and Member of Audit Committee
Robert V. Sinnott(2)	64	Director
Vicky Sutil(2)	49	Director

* Indicates chairman of committee.

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

(2) These individuals also serve as members of the GP LLC board of directors.

Greg L. Armstrong has served as Chairman of the Board and Chief Executive Officer of our general partner since July 2013 and as Chairman of the Board and Chief Executive Officer of PAA s general partner since PAA s formation in 1998. He has also served as a director of PAA s general partner or former general partner since PAA s 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 a director and Chairman of the Federal Reserve Bank of Dallas, Houston Branch, and a director of National Oilwell Varco, Inc. Mr. Armstrong previously served as a director of BreitBurn Energy Partners, L.P. Mr. Armstrong is Chairman, Chief Executive and a director of PNGS GP LLC, the general partner of PAA Natural Gas Storage, L.P., which, as of December 31, 2013, is no longer a publicly traded entity. Mr. Armstrong is also a member of the advisory board of the Maguire Energy Institute at the Cox School of Business at Southern Methodist University, the National Petroleum Council and the Foundation for The Council on Alcohol and Drugs Houston.

Harry N. Pefanis has served as President and Chief Operating Officer of our general partner since July 2013 and as President and Chief Operating Officer of PAA s general partner since PAA s formation in 1998. He was also a director of PAA s 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 PAA s formation. Mr. Pefanis is a director of Settoon Towing. Mr. Pefanis is Vice Chairman and a director of PNGS GP LLC, the general partner of PAA Natural Gas Storage, L.P., which, as of December 31, 2013, is no longer a publicly traded entity.

Mark J. Gorman has served as Executive Vice President Operations and Business Development of our general partner since July 2013 and as Executive Vice President Operations and Business Development of PAA s general partner since February 2013. He previously served as Senior Vice President Operations and Business Development from August 2008 until February 2013, and 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, and a managing director of Eagle Ford Pipeline, LLC.

Phillip D. Kramer has served as Executive Vice President of our general partner since July 2013 and as Executive Vice President of PAA s general partner since November 2008. He previously served as Executive Vice President and Chief Financial Officer from PAA s 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.

Richard K. McGee has served as Executive Vice President, General Counsel and Secretary of our general partner since July 2013 and as Executive Vice President, General Counsel and Secretary of PAA s general partner since February 2013. He served as Vice President, General Counsel and Secretary from March 2012 until February 2013 and served as Vice President and Deputy General Counsel from August 2011 through March 2012. He also serves as Executive Vice President, General Counsel and Secretary for PAA s natural gas storage business, where he was Vice President Legal and Business Development from September 2009 through March 2012. From January 1999 to July 2009, he was employed by Duke Energy, serving as President of Duke Energy International from October 2001 through July 2009 and serving as general counsel of Duke Energy Services from January 1999 through September 2001. He previously spent 12 years at Vinson & Elkins L.L.P., where he was a partner with a focus on acquisitions, divestitures and development work for various clients in the energy industry.

John R. Rutherford has served as Executive Vice President of our general partner since July 2013 and as Executive Vice President of PAA s general partner since October 2010. Mr. Rutherford has 25 years of energy and investment banking experience, most recently serving as Managing Director and Head of North American Energy at Lazard, Freres & Co. Prior to joining Lazard, Mr. Rutherford worked at Simmons & Company International for 10 years, where he served as Managing Director and Partner and played a leadership role in building its financial advisory businesses in the mid-stream, downstream, and exploration and production sectors. During his career, Mr. Rutherford has developed substantial experience advising clients on mergers and acquisitions, corporate restructurings and other strategic actions, including many transactions in which he represented PAA.

Al Swanson has served as Executive Vice President and Chief Financial Officer of our general partner since July 2013 and as Executive Vice President and Chief Financial Officer of PAA s general partner since February 2011. He previously served as Senior Vice President and Chief Financial Officer from November 2008 through February 2011, 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 Executive Vice President, Chief Financial Officer and Director of PNGS GP LLC, the general partner of PAA Natural Gas Storage, L.P., which, as of December 31, 2013, is no longer a publicly traded entity.

John P. vonBerg has served as Executive Vice President Commercial Activities of our general partner since February 2014 and served as Senior Vice President Commercial Activities of our general partner from July 2013 until February 2014. He has also served as Executive Vice President Commercial Operations of PAA s general partner since February 2014. Previously he served as Senior Vice President Commercial Activities of PAA s general partner from August 2008 until February 2014, 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.

W. David Duckett has served as President of Plains Midstream Canada since June 2003, and served as Executive Vice President of Plains Midstream Canada 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.

Chris Herbold has served as Vice President Accounting and Chief Accounting Officer of our general partner since July 2013 and as Vice President Accounting and Chief Accounting Officer of PAA s general partner since August 2010. He served as Controller of PAA from 2008 until August 2010. He previously served as Director of Operational Accounting from 2006 to 2008, Director of Financial Reporting and Accounting from 2003 to 2006 and Manager of SEC and Financial Reporting from 2002 to 2003. Prior to joining PAA in April 2002, Mr. Herbold spent seven years working for the accounting firm Arthur Andersen LLP.

Victor Burk has served as a director of our general partner since January 2014. He has been a Managing Director for Alvarez and Marsal, a privately owned professional services firm since April 2009. From 2005 to 2009, Mr. Burk was the global energy practice leader for Spencer Stuart, a privately owned executive recruiting firm. Prior to joining Spencer Stuart, Mr. Burk served as managing partner of Deloitte & Touche s global oil and natural gas group from 2002 to 2005. He began his professional career in 1972 with Arthur Andersen and served as managing partner of Arthur Andersen s global oil and natural gas group from 1989 until 2002. Mr. Burk is on the board of directors of EV Management, LLC, the ultimate general partner of EV Energy Partners, L.P., a publicly traded limited partnership engaged in the acquisition, development and production of oil and natural gas. Mr. Burk served as a director and as chairman of the audit committee of PNGS GP LLC, the general partner of PAA Natural Gas Storage, L.P., from April 2010 through December 2013. Mr. Burk also serves as a board member of the Independent Petroleum Association of America (Southeast Texas Region) and the Sam Houston Area Council of the Boy Scouts of America. He received a BBA in Accounting from Stephen F. Austin State University, graduating with highest honors. The board of directors of our general partner has determined that Mr. Burk is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. We believe that Mr. Burk s background, spanning over 30 years of extensive public accounting and consulting in the energy industry, coupled with his demonstrated leadership abilities, brings valuable expertise and insight to the board.

Everardo Goyanes has served as a director of our general partner since October 2013. He has served as a director of PAA s general partner or former general partner since May 1999. He is Founder of Ex Cathedra LLC (a consulting firm). Mr. Goyanes served as Chairman of Liberty Natural Resources from April 2009 until August 2011. 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 Masters degree in Finance (honors) from Babson Institute. The board of directors of our general partner 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.

John T. Raymond has served as a director of our general partner since October 2013. He has served as a director of PAA s general partner since December 2010. Mr. Raymond is an owner and founder of EMG, a diversified natural resource private equity fund manager with approximately $8.4 billion of total investor commitments (including co-investments), and has been Managing Partner and CEO since EMG s inception in 2006. Previous to that time, Mr. Raymond held leadership positions with various energy companies, including President and CEO of Plains Resources Inc. (the predecessor entity for Vulcan Energy), President and Chief Operating Officer of Plains Exploration and Production Company and Director of Development for Kinder Morgan, Inc. Mr. Raymond has been a direct or indirect owner of PAA s general partner since 2001 and served on the board of PAA s general partner from 2001 to 2005. Mr. Raymond serves on numerous other boards, including NGL Energy Holdings LLC, the general partner of NGL Energy Partners, L.P., and Tallgrass MLP GP, LLC, the general partner of Tallgrass Energy Partners, L.P. Mr. Raymond received a BSM degree from the A.B. Freeman School of Business at Tulane University with dual concentrations in finance and accounting. We believe that Mr. Raymond s experience with investment in and management of a variety of upstream and midstream assets and operations provides a valuable resource to the board.

Bobby S. Shackouls has served as a director of our general partner since January 2014. Mr. Shackouls served as Chairman of Burlington Resources Inc. from 1997 until its acquisition by ConocoPhillips in 2006, and continued to serve on the ConocoPhillips Board of Directors until his retirement in May 2011. Prior thereto, Mr. Shackouls served as President and Chief Executive Officer of Meridian Oil, Inc, a wholly owned subsidiary of Burlington Resources, from 1994-1995, and as President and Chief Executive Officer of Burlington Resources from 1995 until 2006. Mr. Shackouls currently serves as a director and member of the audit and corporate governance committees of The Kroger Co. and as a director and member of the compensation committee of Oasis Petroleum. He served as a director and member of the audit committee of PNGS GP LLC, the general partner of PAA Natural Gas Storage, L.P., from April 2010 through December 2013. The board of directors of our general partner has determined that Mr. Shackouls is independent under applicable NYSE rules. We believe that Mr. Shackouls extensive experience within the energy industry offers valuable perspective and, in tandem with his long history of leadership as the CEO of a public company, make him highly qualified to serve as a member of the board.

Robert V. Sinnott has served as a director of our general partner since October 2013. He has served as a director of PAA s general partner or former general partner since September 1998. Mr. Sinnott is President, Chief Executive 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 CEO role in 2010. He is also President of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. Mr. Sinnott served as a director of Kayne Anderson Energy Development Company from 2006 through June 2013. He was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992. Mr. Sinnott received a BA from the University of Virginia and an MBA from Harvard. Mr. Sinnott s extensive investment management background includes his current role of managing approximately $22 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.

Vicky Sutil has served as a director of our general partner since October 2013. She has served as a director of PAA s general partner since December 2010. Ms. Sutil is Director, Corporate Development Midstream, and Director, Business Development Rockies, for Oxy, where she has led and worked on a variety of international and domestic oil and gas acquisitions. Her prior positions at Oxy have included Senior Manager, Corporate Development, Manager, Financial Planning and Analysis, and Senior Business Analyst. Before joining Oxy in 2000, Ms. Sutil worked for ARCO Products Company as a Business Analyst for the Refining and Retail Marketing divisions, and Senior Project Manager for the Refining Division. Earlier, she held a variety of engineering positions

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at Mobil Oil Corporation. Ms. Sutil served as Oxy s designated observer of the board of PAA s general partner from 2008, when Oxy acquired its initial interest in PAA s general partner, until December 2010. Ms. Sutil received a BS in Mechanical Engineering Petroleum Emphasis from the University of California, Berkeley, and an MBA from Pepperdine University. We believe that Ms. Sutil s financial and analytical background, coupled with her knowledge of engineering, provides the board a distinctive and valuable perspective.

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.plainsallamerican.com.*

Based solely upon a review of the copies of Forms 3 and 4 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our executive officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2013, except as follows:

- Mr. Armstrong timely filed a Form 3 on October 15, 2013, the effective date of our initial public offering, but, due to a technical filing error, it was inadvertently coded to an inactive issuer with the same name. A filing that was coded to the correct issuer was submitted on October 21, 2013.

- Messrs. Herbold, McGee and Raymond each were late in filing a Form 4 to report the acquisition of interests in us in connection with the closing of our initial public offering on October 21, 2013. The Forms 4 were filed on October 24, 2013.

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Item 11. ***Executive Compensation***

Compensation Committee Report

Our general partner s board of directors performs the functions of a compensation committee. Accordingly, the board of directors of our general partner has reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on those reviews and discussions, the board of directors has recommended that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2013 for filing with the SEC.

Greg L. Armstrong
Victor Burk
Everardo Goyanes
John T. Raymond
Bobby S. Shackouls
Robert V. Sinnott
Vicky Sutil

Compensation Committee Interlocks and Insider Participation

Our general partner s board of directors performs the functions of a compensation committee. Mr. Armstrong, our Chief Executive Officer, also serves as a director and executive officer of GP LLC. No other member of our general partner s board of directors serves as an executive officer of us or PAA. Mr. Goyanes serves as a director of GP LLC and as chairman of its audit committee, and Messrs. Raymond, Sinnott and Ms. Sutil serve as directors of GP LLC and as members of its compensation committee. Mr. Raymond is associated with EMG, Mr. Sinnott is associated with Kayne Anderson and its affiliates, and Ms. Sutil is associated with Oxy. We have relationships with these entities. See Item 13. Certain Relationships and Related Transactions, and Director Independence Related Party Transactions.

Compensation Discussion and Analysis

We and our general partner were formed in July 2013. As such, neither we nor our general partner accrued any obligations with respect to compensation for our executive officers or directors for the fiscal year ended December 31, 2012, or any period prior to completion of our initial public offering in October 2013.

Neither we nor our general partner have employees. All of our officers and other personnel necessary for our business to function (to the extent not out-sourced) are employed by GP LLC, and AAP, on our behalf, pays GP LLC an annual fee for general and administrative services. See Item 13. Certain Relationships and Related Transactions, and Director Independence Related Party Transactions Administrative Agreement. Applicable disclosure rules require us to discuss certain aspects of the compensation of any of our Named Executive Officers, which are generally defined to include our Chief Executive Officer (CEO), our Chief Financial Officer (CFO), and the three other most highly compensated executive officers who received compensation in excess of $100,000 during the previous fiscal year. References within this

Compensation Discussion and Analysis to our Named Executive Officers and to PAA s Named Executive Officers refer to Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg.

We do not separately compensate our Named Executive Officers; rather, their management of our business is part of the service provided by GP LLC under the Administrative Agreement. Moreover, substantially all responsibility and authority for compensation-related decisions resides with the compensation committee of GP LLC. Our Named Executive Officers participate in the employee benefit plans and arrangements of GP LLC and PAA, including plans that may be established in the future. Neither we nor our general partner have entered into any employment or benefits-related agreements with any individual who provides executive officer services to us, and, except for the LTIP and potential awards under such plan, we do not anticipate entering into any such agreement in the future. The Administrative Agreement, which governs the reimbursement of GP LLC by AAP for AAP s allocable share of costs and expenses borne or incurred by GP LLC for the benefit of AAP, us or our general partner does not cover any costs we may incur that are attributable to any future awards we may grant under the LTIP. Any

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such costs will be borne by AAP as determined by our general partner s board of directors, who is responsible for the administration of our LTIP, the issuance of any awards thereunder and approval of any compensation payable to our general partner s non-employee directors.

The compensation information set forth in this section discloses the compensation discussion and analysis of PAA for the year ended December 31, 2013. This section will provide insight into GP LLC s compensation philosophy and policies that governed the compensation of our Named Executive Officers as it relates to their services performed on behalf of PAA during the 2013 fiscal year.

PAA Background

All of PAA s officers and employees (other than Canadian personnel) are employed by GP LLC. PAA s Canadian personnel are employed by Plains Midstream Canada, which is a wholly owned subsidiary. Under its partnership agreement, PAA is required to reimburse its general partner and its general partner s affiliates for all employment-related costs, including compensation for executive officers, other than expenses related to the AAP Management Units (which are borne entirely by AAP).

Objectives

Since PAA s inception, it has 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 compensation at risk. The primary long-term measure of PAA s performance is its ability to increase its sustainable quarterly distribution to its unitholders. PAA believes its pay-for-performance approach aligns the interests of its executive officers with that of its equity holders, and at the same time enables PAA to maintain a lower level of base overhead in the event operating and financial performance is below expectations. PAA s executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute PAA s 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 PAA s unitholders, and to reward success in reaching such goals. PAA uses 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 PAA s 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. PAA does not maintain a defined benefit or pension plan for its executive officers as PAA believes such plans primarily reward longevity and not performance. PAA provides 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, PAA also reimburses certain Named Executive Officers and other employees for club dues and similar expenses. PAA considers these benefits and reimbursements to be typical of other employers, and it does not believe they are distinctive of its compensation program.

Elements of Compensation

Salary. PAA does not benchmark salary or bonus amounts. In practice, PAA believes its salaries are generally competitive with the narrower universe of large-cap master limited partnerships, but are moderate relative to the broad spectrum of energy industry competitors for similar talent.

Cash Bonuses. PAA s cash bonuses include annual discretionary bonuses in which all of its current domestic Named Executive Officers potentially participate, as well as a quarterly bonus program in which Mr. vonBerg participates. Mr. Duckett participates in an annual and quarterly bonus program that is specific to activities managed by PAA s Canadian personnel.

Long-Term Incentive Awards. The primary long-term measure of PAA s performance is its ability to increase its sustainable quarterly distribution to its unitholders. Historically, PAA has used performance-indexed phantom unit grants issued under its Long-Term Incentive Plans to encourage and reward timely achievement of targeted distribution levels and align the long-term interests of its Named Executive Officers with those of its

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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). PAA does not use options as a form of incentive compensation. Unlike vesting of an option, vesting of a phantom unit results in delivery of a common unit or cash of equivalent value as opposed to a right to exercise. Terms of historical phantom unit grants have varied, but generally phantom units vest upon the later of achievement of targeted distribution threshold levels and continued employment for periods ranging from two to five years. These distribution performance thresholds are generally consistent with PAA s targeted range for distribution growth. To encourage accelerated performance, if PAA meets certain distribution thresholds prior to meeting the minimum service requirement for vesting, PAA s 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 AAP authorized the creation of Class B units of AAP (the AAP Management Units) and authorized GP LLC s compensation committee to issue grants of AAP Management Units to create additional long-term incentives for PAA s management designed to attract talent and encourage retention over an extended period of time. The entire economic burden of the AAP Management Units is borne solely by AAP, and does not impact PAA s cash or units outstanding.

The AAP Management Units are subject to restrictions on transfer and generally become incrementally earned (entitled to receive a portion of the distributions that would otherwise be paid to PAA s general partner) upon achievement of certain performance thresholds, which are aligned with the interests of PAA s common unitholders. As of February 15, 2014, 100% of the outstanding AAP Management Units granted in 2007, 2009, 2010 and 2011 had been earned (or will be earned within 180 days), and 25% of the AAP Management Units granted in 2013 had been earned. No AAP Management Units were granted in 2008 or 2012.

To encourage retention following achievement of these performance benchmarks, AAP retained a call right to purchase any earned AAP Management Units at a discount to fair market value that is exercisable upon the termination of a holder s employment with GP LLC and its affiliates (other than a termination without cause or by the employee for good reason) prior to certain stated dates. If a holder of an AAP Management Unit remains employed past such designated date (or prior to such date is terminated without cause or quits for good reason), any earned units are no longer subject to the call right and are deemed to have vested. The applicable designated dates for the various AAP Management Unit grants range from January 1, 2016 for AAP Management Units granted in 2007 to January 1, 2021 for AAP Management Units granted in 2013. In order to encourage retention, the size of the discount to fair market value reflected in the potential call right purchase price decreases over time pursuant to a formula set forth in each AAP Management Unit grant agreement. AAP Management Unit grants also provide that all earned AAP Management Units and a portion of any unearned and unvested AAP Management Units will vest upon a change of control. All earned AAP Management Units will also vest if AAP elects not to timely exercise its call right.

If at any time after December 31, 2015 our Class A shares are publicly traded, each vested AAP Management Unit may be converted into AAP units and a like number of PAGP Class B shares based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and was approximately 0.90 AAP units and PAGP Class B shares for each AAP Management Unit as of December 31, 2013 and approximately 0.91 as of February 15, 2014). Following any such conversion, the resulting AAP units and PAGP Class B shares are exchangeable for PAGP Class A shares on a one-for-one basis as provided in the PAGP limited partnership agreement. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner AAP Management Units.

Transaction/Transition Grants. In connection with the initial public offering of PNG in 2010, PAA created a plan based on PNG equity, which was designed to reward and create incentive for certain of PAA s officers who were instrumental in developing the natural gas storage business and bringing it to the point of the IPO, and who would continue to allocate meaningful amounts of time to the business. In September 2010, PAA entered into transaction/transition grant agreements with Messrs. Armstrong, Pefanis and Swanson, pursuant to which they acquired, in equal proportion, phantom common units, phantom series A subordinated units and phantom series B subordinated units representing a portion of the limited partner interest of PNG issued to PAA in connection with

PNG s IPO. The phantom common units vested in equal one-half increments in May 2011 and May 2012. Messrs. Armstrong, Pefanis and Swanson unilaterally surrendered the unvested portion of these grants, which consisted of all of the phantom series A subordinated units and phantom series B subordinated units, on December 31, 2013 in connection with the closing of the PNG Merger.

Relation of Compensation Elements to Compensation Objectives

PAA s compensation program is designed to motivate, reward and retain its 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 AAP Management 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 AAP Management Units subject to AAP 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 vesting profile of the AAP Management 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 GP LLC s compensation committee in reviewing and making recommendations, a compensation tally sheet is prepared by GP LLC s CEO and General Counsel and provided to the compensation committee.

PAA stresses performance-based compensation elements to attempt to create a performance-driven environment in which its 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 PAA even after meeting long-term performance thresholds in order to meet the minimum service periods and by the potential for rewards yet to come. PAA believes its compensation philosophy as implemented by application of the three primary compensation elements (i) aligns the interests of its Named Executive Officers with its unitholders, (ii) positions PAA to achieve its business goals, and (iii) effectively encourages the exercise of sound judgment and risk-taking that is conducive to creating and sustaining long-term value. PAA believes the processes employed by the GP LLC compensation committee and 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.

PAA believes its compensation program has been instrumental in its achievement of stated objectives. Over the five-year period ended December 31, 2013, PAA s annual distribution per common unit has grown at a compound annual rate of 6.10% and the total return realized by PAA s unitholders for that period averaged approximately 32.1% per annum. During this period, PAA has enjoyed a very high rate of retention among executive officers.

Application of Compensation Elements

Salary. PAA does not make systematic annual adjustments to the salaries of its Named Executive Officers. PAA does, however, make salary adjustments as necessary to maintain hierarchical relationships among senior management levels after new senior management members are added to keep pace with its overall growth. Since the date of PAA s initial public offering in 1998 (or date of employment, if later) through December 31, 2013, Messrs. Armstrong, Pefanis and vonBerg have each received one salary adjustment, Mr. Duckett has received small salary adjustments in line with other Canadian personnel, 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 PAA s performance relative to its annual plan forecast and public guidance (typically provided quarterly in conjunction with release of earnings), 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 GP LLC board of directors in conjunction with the review and authorization of PAA s annual plan.

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At the end of each year, the CEO performs a quantitative and qualitative assessment of PAA s performance relative to its 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. PAA s primary performance metric is its ability to generate increasing and sustainable cash distributions to its unitholders. Accordingly, although net income and net income per unit are monitored to highlight inconsistencies with primary performance metrics, as is PAA s market performance relative to its MLP peers and major indices, these metrics are considered secondary performance measures. The CEO s written analysis of PAA s performance examines 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 GP LLC for review and comment. Based on the conclusions set forth in the annual performance review, the CEO submits recommendations to the GP LLC compensation committee for bonuses to the other Named Executive Officers taking into account the relative contribution of the individual officer. There are no set formulas for determining the annual discretionary bonus for the Named Executive Officers. Factors considered by the CEO in determining the level of bonus in general include (i) whether or not PAA 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) PAA s relative prospects at the end of the year with respect to future growth and performance; and (vi) PAA s positioning at the end of the year with respect to its targeted credit profile. The CEO takes these factors into consideration as well as the relative contributions of each of the Named Executive Officers to the year s performance in developing his recommendations for bonus amounts.

These recommendations are discussed with the GP LLC compensation committee, adjusted as appropriate, and submitted to the GP LLC board of directors for its review and approval. Similarly, the GP LLC compensation committee assesses the CEO s contribution toward meeting PAA s goals, and recommends a bonus for the CEO it believes to be commensurate with such contribution. In several historical instances, the CEO and the President have requested that the bonus amount recommended by the GP LLC compensation committee be reduced to maintain a closer relationship to bonuses awarded to the other Named Executive Officers. Accordingly, the current practice is for the CEO to submit to the GP LLC 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 GP LLC compensation 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 GP LLC compensation committee for review and recommendation to the GP LLC board.

U.S. Bonus based on Adjusted EBITDA. Mr. vonBerg and certain other members of PAA s U.S.-based senior management team are directly involved in activities that generate partnership earnings. These individuals, along with other employees in PAA s marketing and business development groups participate in a quarterly bonus pool, the size of which is 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. The size of the bonus pool, and the allocation of quarterly bonus amounts among all participants based on relative contribution, is recommended by Mr. Pefanis and reviewed, modified and approved by Mr. Armstrong, as appropriate. Messrs. Pefanis and Armstrong do not participate in the quarterly bonus pool. The quarterly bonus amounts for Mr. vonBerg are taken into consideration in determining the recommended annual discretionary bonus submitted by the CEO to the GP LLC compensation committee.

Annual Bonus and Quarterly Bonus based on Adjusted EBITDA (Canada). Substantially all of the personnel employed by Plains Midstream Canada (including Mr. Duckett) or involved in Canadian operations participate in a bonus pool under a program established at the time of PAA s 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

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is recommended by Mr. Duckett and reviewed, adjusted if warranted, and approved by Mr. Pefanis. Mr. Pefanis does not participate in the bonus pool. Mr. Duckett receives a quarterly bonus equal to approximately 40% of his participation level for the first three fiscal quarters of the year. He receives an annual bonus consisting of 60% of his participation in the first three quarters and 100% of his participation in the fourth quarter.

Long-Term Incentive Awards. PAA does not make systematic annual phantom unit awards to its Named Executive Officers. Instead, PAA s objective is to time the granting of awards such that the creation of new long-term incentives coincides with the satisfaction of performance thresholds under existing awards. Thus, performance is rewarded by relatively greater frequency of awards, and lack of performance by relatively lesser frequency of awards. Generally, PAA believes that a grant cycle of approximately three years (and extended time-vesting requirements) provides a balance between a meaningful retention period for PAA and a visible, reachable reward for the executive officer. Achievement of performance targets does not shorten the minimum service period requirement. If top performance targets on outstanding awards are achieved in the early part of this cycle, new awards are granted with higher performance thresholds, and the minimum service periods of the new awards are generally synchronized with the remaining time-vesting requirements of outstanding awards in a manner designed to encourage extended retention of PAA s 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 AAP authorized the creation of AAP Management Units, which the compensation committee of GP LLC is authorized to administer. See Elements of Compensation Long-Term Incentives. These AAP Management Units are limited to 52,125,935 authorized units, of which approximately 48,642,830 were outstanding as of December 31, 2013 pursuant to individual restricted units agreements between AAP and certain members of PAA s management. As of December 31, 2013 PAA s Named Executive Officers held 28,931,571 of the restricted AAP Management Units. The remaining available AAP Management Units are administered at the discretion of GP LLC s 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 2013

At the beginning of 2013, PAA established four public goals with paraphrased versions of these goals overlapping two of its five internal goals.

The four public goals for the year were to:

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

2. Successfully execute PAA s 2013 capital program and set the stage for growth in 2014 and beyond;

3. Increase PAA s November 2013 annualized distribution level by approximately 9% to 10% over the November 2012 annualized distribution level; and

4. Selectively pursue strategic and accretive acquisitions.

Additionally, PAA s internal qualitative goals included (a) advancing multi-year programs and initiatives and preparing the organization for future growth, (b) continuing to promote a culture of safety and environmental responsibility throughout the organization, and (c) realizing targeted synergies and opportunities from the BP NGL Acquisition and completing remaining material integration activities.

In general, PAA substantially achieved or exceeded all of these goals.

- PAA s adjusted EBITDA and distributable cash flow exceeded its 2013 guidance furnished in the February 6, 2013 Form 8-K by approximately 13% and 15%, respectively;

- PAA executed a $1.62 billion expansion capital program generally on time and on budget, and refined and expanded its portfolio of organic growth projects, setting up a 2014 program of approximately $1.7 billion;

- PAA completed integration of the BP NGL Acquisition and generated/exceeded its acquisition model EBITDA forecasts for 2013. PAA also continued to focus on extracting further commercial synergies and identifying additional organic growth opportunities associated with the acquired assets;

- PAA increased its annualized distribution rate by 10.6% to $2.40 per common unit, while maintaining distribution coverage of approximately 143%;

- PAA executed multiple financings that enabled it to fund its expansion capital expenditures while maintaining solid financial strength and high liquidity, including raising an aggregate of approximately $1.15 billion of long-term debt and equity capital, extending and lowering pricing on $3 billion of bank credit facilities, initiating a $1.5 billion commercial paper program and retaining $500 million of cash flow in excess of distributions;

- PAA initiated and executed the PAGP initial public offering and completed the acquisition of all of the publicly held units of PNG; and

- PAA executed multiple initiatives to sustain the organization, prepare it for future growth and promote a culture of safety and environmental responsibility.

For 2013, the elements of compensation were applied as described below.

Salary. No salary adjustments for Named Executive Officers were recommended or made in 2013.

Cash Bonuses. Based on the CEO s annual performance review and the individual performance of each of PAA s Named Executive Officers, the GP LLC compensation committee recommended to the GP LLC board of directors and the GP LLC 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 PAA s 2013 goals; the absence of shortfalls relative to expectations; the level of difficulty associated with achieving such objectives; PAA s 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 PAA s positioning at the end of the year with respect to its targeted credit profile. As noted in the CEO s annual performance review, although performance in 2013 was very solid, PAA s performance during 2012 was considered outstanding and thus superior to 2013 on a relative basis. As a result, overall bonuses for 2013 for PAA s Named Executive Officers as a group were, on average, approximately 10% below 2012 bonus levels. In the case of Mr. Duckett, the aggregate bonus amount reflected in the Summary Compensation Table for 2013 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 reflected in the Summary Compensation Table for 2013 represented approximately 36% in annual bonus and 64% in quarterly bonus.

Long-Term Incentive Awards. Prior to 2013, the last grant cycle of equity awards to PAA s Named Executive Officers occurred in 2010. All of the performance thresholds for vesting of the 2010 awards had been met as of December 31, 2012; however, vesting under such awards remained subject to minimum service periods that extend to May 2015. Consistent with its policy of issuing new grants with extended time-vesting periods when attainment of the distribution performance thresholds of existing grants has occurred, in February 2013, the board of directors of PAA s general partner granted new awards to PAA s Named Executive Officers designed to incentivize continued growth and fundamental performance, as well as encourage retention. The phantom units covered by these awards will vest in one-third increments as follows: (i) one-third will vest upon the later of the August 2016 distribution date and the date PAA pays a quarterly distribution of at least $0.5875 ($2.35 annualized) per common unit, (ii) one

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third will vest upon the later of the August 2017 distribution date and the date PAA pays a quarterly distribution of at least $0.6250 ($2.50 annualized) per common unit, and (iii) one-third will vest upon the later of the August 2018 distribution date and the date PAA pays a quarterly distribution of at least $0.6625 ($2.65 annualized) per common unit. Upon vesting, the phantom units are payable on a one-for-one basis in PAA common units. These phantom units include tandem DERs that will vest (i.e., commence receiving cash distributions as if the underlying common units were owned) in one-third increments upon achieving the referenced distribution performance thresholds, without regard to the minimum service period. The DERs expire when the associated phantom units vest. Any of these phantom units (and all associated DERs) that have not vested as of the August 2019 distribution date will be forfeited. The 2013 awards included grants to PAA s Named Executive Officers as follows: Mr. Armstrong 150,000; Mr. Pefanis 135,000; Mr. Swanson 100,000; Mr. Duckett 100,000; and Mr. vonBerg 75,000.

Other. In connection with the closing of the PNG Merger on December 31, 2013, Messrs. Armstrong, Pefanis and Swanson unilaterally surrendered the unvested portion of their respective Transaction/Transition Grants, which consisted of all of the previously granted phantom series A subordinated units and phantom series B subordinated units.

Other Compensation Related Matters

Equity Ownership in PAA. As of December 31, 2013, PAA s Named Executive Officers collectively owned substantial equity in PAA. Although PAA encourages its Named Executive Officers to acquire and retain ownership in PAA, it does not have a policy requiring maintenance of a specified equity ownership level. PAA s policies prohibit its Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership. As of December 31, 2013, PAA s Named Executive Officers beneficially owned, in the aggregate, (i) approximately 2.4 million PAA common units (excluding any unvested equity awards), (ii) through their ownership of interests in PAA Management, L.P., an approximate 2.0% indirect ownership interest (approximate 1.9% economic interest including the dilutive effect of the AAP Management Units) in AAP, which directly owns all of PAA s IDRs and indirectly owns a 2% general partner interest in PAA, and (iii) 28,931,571 AAP Management Units, which represent an approximate 4.1% economic interest in AAP. Based on the market price of PAA s common units and PAGP s Class A shares at December 31, 2013 and assuming the conversion of all earned AAP Management Units into AAP units at a conversion factor of approximately 0.90 and the exchange of such AAP units for an equivalent number of PAGP Class A shares, the value of the equity ownership of these individuals was significantly greater than the combined aggregate salaries and bonuses of these individuals for 2013.

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

Section 162(m). With respect to the deduction limitations under Section 162(m) of the Code, PAA is a limited partnership and does not fall within 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 PAA s Named Executive Officers, and the AAP Management Unit grant agreements to which PAA s Named Executive Officers are a party include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreements. 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 GP LLC). PAA believes this double trigger arrangement is appropriate because it provides assurance to the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The provisions in the employment agreements for Messrs. Armstrong and Pefanis become operative only if the executive terminates employment within three months of the change in control. Messrs. Armstrong and Pefanis agreed to a conditional waiver of these provisions with respect to Vulcan Energy

Corporation s (Vulcan Energy) sale of its 50.1% general partner interest in December 2010 and with respect to the completion of the initial public offering of PAGP in October 2013. The AAP Management Unit grant 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 AAP Management Units would be forfeited (unless waived at the discretion of the general partner or acquirer as the case may be). As a result

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of significant participation by existing general partner owners or their affiliates in the December 2010 sale of Vulcan Energy s 50.1% ownership in the general partner, the change of control provisions of the AAP Management Unit grant agreements were not triggered. In addition, the completion of the initial public offering of PAGP in October 2013 did not constitute a change of control pursuant to the terms of the AAP Management Unit grant agreements. See Employment Contracts and Potential Payments upon Termination or Change-in-Control. The provision of severance or equity acceleration for certain terminations and change of control help to create a retention tool by assuring the executive that the benefit of the employment arrangement will be at least partially realized despite the occurrence of an event that would materially alter the employment arrangement.

Relation of Compensation Policies and Practices to Risk Management

PAA s 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 PAA, such risks would primarily attach to certain commercial activities conducted in its 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, PAA s policy is to conduct its 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 Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model Risk Management in Part I of this annual report. PAA also routinely monitors and measures the execution and performance of its capital projects and acquisitions relative to expectations.

PAA s 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 PAA s risk management policies and practices or of PAA s Code of Business Conduct. In addition, PAA s long-term incentive awards typically include vesting criteria based on payment of distributions from currently available cash. See Compensation Discussion and Analysis Relation of Compensation Elements to Compensation Objectives.

In combination with PAA s risk-management practices, PAA does not believe that risks arising from its compensation policies and practices for its employees are reasonably likely to have a material adverse effect on it.

Summary Compensation Table

The following table sets forth certain compensation information for PAA s Named Executive Officers. PAA reimburses its general partner and its affiliates for expenses incurred on PAA s behalf, including the costs of officer compensation (excluding the costs of the obligations represented by the AAP Management Units).

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong	2013	375,000	4,400,000	2,662,378	16,740	7,454,118
Chairman and Chief Executive	2012	375,000	5,200,000		16,320	5,591,320
Officer	2011	375,000	5,000,000		15,900	5,390,900
Harry N. Pefanis	2013	300,000	4,250,000	2,396,140	16,740	6,962,880
President and Chief Operating	2012	300,000	5,000,000		16,320	5,316,320
Officer	2011	300,000	4,800,000		15,900	5,115,900
Al Swanson	2013	250,000	1,800,000	1,774,919	16,740	3,841,659
Executive Vice President and	2012	250,000	2,000,000		16,320	2,266,320
Chief Financial Officer	2011	250,000	1,750,000		15,900	2,015,900
W. David Duckett(3)	2013	276,666	3,887,652	1,774,919	102,936	6,042,173
President Plains Midstream	2012	285,380	4,080,876		115,433	4,481,689
Canada	2011	288,799	4,017,220		106,744	4,412,763
John P. vonBerg	2013	250,000	5,255,000(4)	1,331,189	16,740	6,852,929
Executive Vice President	2012	250,000	6,315,000(4)		16,320	6,581,320
Commercial Activities	2011	250,000	5,220,000(4)		15,900	5,485,900

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(1) Grant date fair values are presented for LTIP phantom unit grants awarded to Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg in 2013. Dollar amounts represent the aggregate grant date fair value of phantom units awarded based on the probable outcome of underlying performance conditions pursuant to FASB ASC Topic 718. The performance threshold for the first tranche of vesting was deemed probable of occurring on the grant date. The maximum grant date fair values of phantom unit grants awarded in 2013 assuming that the highest level of performance conditions will be met are: $7,562,664 for Mr. Armstrong; $6,806,398 for Mr. Pefanis; $5,041,776 for Mr. Swanson; $5,041,776 for Mr. Duckett and $3,781,332 for Mr. vonBerg. See Note 15 to our Consolidated Financial Statements for further discussion regarding the calculation of grant date fair values.

(2) 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 $15,300 in such contributions for 2013. 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 2013, employer contributions to the Plains Midstream Canada savings plan of $35,967, group term life insurance premiums of $29,314, automobile lease payments of $30,369 and club dues of $7,286.

(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 $3,355,000, $4,115,000 and $3,220,000 and annual bonuses of $1,900,000, $2,200,000 and $2,000,000 in 2013, 2012 and 2011, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Grants of Plan-Based Awards Table

The following table sets forth summary information regarding all grants of plan-based awards made to PAA s Named Executive Officers during the fiscal year ended December 31, 2013.

Name	Grant Date	All Other Stock Awards: Number Of Shares Of Stock or Units (#)	Grant Date Fair Value Of Stock and Option Awards ($)(2)
Greg L. Armstrong	2/21/13	150,000(1)	2,662,378
Harry N. Pefanis	2/21/13	135,000(1)	2,396,140
Al Swanson	2/21/13	100,000(1)	1,774,919
W. David Duckett	2/21/13	100,000(1)	1,774,919

John P. vonBerg	2/21/13	75,000(1)	1,331,189

(1) The phantom units covered by these awards will vest in one-third increments as follows: (i) one-third will vest upon the later of the August 2016 distribution date and the date PAA pays a quarterly

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distribution of at least $0.5875 ($2.35 annualized) per common unit, (ii) one third will vest upon the later of the August 2017 distribution date and the date PAA pays a quarterly distribution of at least $0.6250 ($2.50 annualized) per common unit, and (iii) one-third will vest upon the later of the August 2018 distribution date and the date PAA pays a quarterly distribution of at least $0.6625 ($2.65 annualized) per common unit. Upon vesting, the phantom units are payable on a one-for-one basis in PAA common units. These phantom units include tandem DERs that will vest (i.e., commence receiving cash distributions as if the underlying common units were owned) in one-third increments upon achieving the referenced distribution performance thresholds, without regard to the minimum service period. The DERs expire when the associated phantom units vest. Any of these phantom units (and all associated DERs) that have not vested as of the August 2019 distribution date will be forfeited.

(2) Represents the grant date fair values of phantom units based on the probable outcome of underlying performance conditions pursuant to FASB ASC Topic 718. The performance threshold for the first tranche of vesting was deemed probable of occurring on the grant date. See footnote 1 to the Summary Compensation Table for the maximum grant date fair values of these phantom unit awards.

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

A narrative description of all material factors necessary to an understanding of the information included in the above Summary Compensation Table and Grant of Plan-Based Awards Table is included in Compensation Discussion and Analysis and in the footnotes to such tables.

Employment Contracts

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

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Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information regarding outstanding equity awards at December 31, 2013 with respect to PAA s Named Executive Officers:

	Unit Awards			
Name	**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	10,425,791(2)	252,288,377		
	240,000(3)	12,424,800		
	50,000(4)	2,588,500	100,000(4)	5,177,000
Harry N. Pefanis	7,819,344(2)	189,216,276		
	160,000(3)	8,283,200		
	45,000(4)	2,329,650	90,000(4)	4,659,300
Al Swanson	2,606,448(2)	63,072,101		
	80,000(3)	4,141,600		
	33,333(4)	1,725,649	66,667(4)	3,451,351
W. David Duckett	4,430,961(2)	107,222,550		
	100,000(3)	5,177,000		
	33,333(4)	1,725,649	66,667(4)	3,451,351
John P. vonBerg	3,649,027(2)	88,300,925		
	72,000(3)	3,727,440		
	25,000(4)	1,294,250	50,000(4)	2,588,500

(1) Market value of phantom units reported in these columns is calculated by multiplying the closing market price ($51.77) of PAA s common units at December 31, 2013 (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. Market value of AAP Management Units is calculated by (i) assuming that such AAP Management Units are converted into AAP units based on the December 31, 2013 conversion factor of approximately 0.90 AAP units and PAGP Class B shares for each AAP Management Unit, (ii) assuming the exchange of the resulting AAP units and PAGP Class B shares for PAGP Class A shares on a one-for-one basis, and (iii) multiplying such resulting number of PAGP Class A shares by the closing market price ($26.77) of PAGP s Class A shares at December 31, 2013 (the last trading day of the fiscal year).

(2) Represents the pre-conversion number of AAP Management Units held by the applicable individual, each of which represents a profits interest in AAP, entitling the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in AAP s asset values, but does not represent an interest in the capital of AAP on

the applicable grant date of the AAP Management Units. Despite the fact that 100% of the AAP Management Units held by PAA s Named Executive Officers had been earned as of December 31, 2013 (i.e., all relevant performance benchmarks have been satisfied), all such AAP Management Units are treated as stock that has not vested for purposes of this table due to the fact that, as of December 31, 2013, they remained subject to a call right held by AAP. Such call right gives AAP the right to purchase such AAP

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Management Units for an amount equal to 75% of the fair market value of such AAP Management Units upon the termination of the applicable Named Executive Officer s employment with GP LLC and its affiliates prior to January 1, 2016 (subject to certain exceptions as set forth in the AAP Management Unit grant agreements). If at any time after December 31, 2015 the PAGP Class A shares are publicly traded, each vested AAP Management Unit may be converted into AAP units and a like number of PAGP Class B shares based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and was approximately 0.90 AAP units and PAGP Class B shares for each AAP Management Unit as of December 31, 2013). Following any such conversion, the resulting AAP units and PAGP Class B shares are exchangeable for PAGP Class A shares on a one-for-one basis as provided in the PAGP limited partnership agreement. For additional information regarding the AAP Management Units, please read Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner AAP Management Units.

(3) Represents phantom units granted in 2010 under PAA s Long-Term Incentive Plan. As of December 31, 2013, all of these phantom units had been earned and will vest one-half on each of the May 2014 and May 2015 distribution dates. All of the DERs associated with these phantom units are currently payable.

(4) Represents phantom units granted in 2013 under PAA s Long-Term Incentive Plan. These phantom units will vest in one-third increments as follows: (i) one-third will vest on the August 2016 distribution date as the quarterly distribution threshold of $0.5875 ($2.35 annualized) has already been satisfied, (ii) one third will vest upon the later of the August 2017 distribution date and the date PAA pays a quarterly distribution of at least $0.6250 ($2.50 annualized) per common unit, and (iii) one-third will vest upon the later of the August 2018 distribution date and the date PAA pays a quarterly distribution of at least $0.6625 ($2.65 annualized) per common unit. Upon vesting, the phantom units are payable on a one-for-one basis in PAA common units. These phantom units include tandem DERs that will vest (i.e., commence receiving cash distributions as if the underlying common units were owned) in one-third increments upon achieving the referenced distribution performance thresholds, without regard to the minimum service period. The DERs expire when the associated phantom units vest. Any of these phantom units (and all associated DERs) that have not vested as of the August 2019 distribution date will be forfeited.

Option Exercises and Units Vested

The following table sets forth certain information regarding the vesting of phantom units during the fiscal year ended December 31, 2013 with respect to PAA s Named Executive Officers.

	Unit Awards	
Name	**Number of Units Acquired on Vesting (#)**	**Value Realized on Vesting ($)**
Greg L. Armstrong	120,000(1)	7,042,800(2)
Harry N. Pefanis	80,000(1)	4,695,200(2)
Al Swanson	40,000(1)	2,347,600(2)
	23,336(1)	1,369,590(2)
W. David Duckett	50,000(1)	2,934,500(2)
John P. vonBerg	36,000(1)	2,112,840(2)

(1) Represents the gross number of phantom units that vested during the year ended December 31, 2013. The actual number of units delivered was net of income tax withholding.

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(2) Consistent with the terms of PAA s Long-Term Incentive Plan, the value realized upon vesting is computed by multiplying the closing market price ($58.69) of PAA s common units on May 14, 2013 (the date preceding the vesting date) by the number of units that vested.

Pension Benefits

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

Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans

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

Potential Payments upon Termination or Change-in-Control

The following table sets forth potential amounts payable to PAA s Named Executive Officers upon termination of employment under various circumstances, and as if terminated on December 31, 2013.

	By Reason of Death ($)	By Reason of Disability ($)	By Company without Cause ($)	By Executive with Good Reason ($)	In Connection with a Change In Control ($)
Greg L. Armstrong					
Salary and Bonus	11,150,000(1)	11,150,000(1)	11,150,000(1)	11,150,000(1)	16,725,000(2)
Equity Compensation	15,013,300(3)	15,013,300(3)	20,190,300(4)	20,190,300(4)	20,190,300(5)
Health Benefits	N/A	30,024(6)	30,024(6)	30,024(6)	30,024(6)
Tax Gross-up	N/A	N/A	N/A	N/A	1,339,190(7)
AAP Management Units	N/A	N/A	63,072,094(8)	63,072,094(8)	63,072,094(9)
Total	26,163,300	26,193,324	94,442,418	94,442,418	101,356,608
Harry N. Pefanis					
Salary and Bonus	10,600,000(1)	10,600,000(1)	10,600,000(1)	10,600,000(1)	15,900,000(2)
Equity Compensation	10,612,850(3)	10,612,850(3)	15,272,150(4)	15,272,150(4)	15,272,150(5)
Health Benefits	N/A	46,688(6)	46,688(6)	46,688(6)	46,688(6)
Tax Gross-up	N/A	N/A	N/A	N/A	1,629,547(7)
AAP Management Units	N/A	N/A	47,304,069(8)	47,304,069(8)	47,304,069(9)
Total	21,212,850	21,259,538	73,222,907	73,222,907	80,152,454
Al Swanson (10)					

Equity Compensation	5,867,249(3)	5,867,249(3)	5,867,249(4)	N/A	9,318,600(5)
AAP Management Units	N/A	N/A	15,768,025(8)	15,768,025(8)	15,768,025(9)
Total	5,867,249	5,867,249	21,635,274	15,768,025	25,086,625
W. David Duckett (10)					
Equity Compensation	6,902,649(3)	6,902,649(3)	6,902,649(4)	N/A	10,354,000(5)
AAP Management Units	N/A	N/A	26,805,638(8)	26,805,638(8)	26,805,638(9)
Total	6,902,649	6,902,649	33,708,287	26,805,638	37,159,638
John P. vonBerg (10)					
Equity Compensation	5,021,690(3)	5,021,690(3)	5,021,690(4)	N/A	7,610,190(5)
AAP Management Units	N/A	N/A	22,075,231(8)	22,075,231(8)	22,075,231(9)
Total	5,021,690	5,021,690	27,096,921	22,075,231	29,685,421

(1) The employment agreements between GP LLC and Messrs. Armstrong and Pefanis provide that if (i) their employment with GP LLC is terminated as a result of their death, (ii) they terminate their employment with GP LLC (a) because of a disability (as defined in Section 409A of the Code) or (b) for good reason (as defined below), or (iii) GP LLC terminates their employment without cause (as defined below), they are

entitled to a lump-sum amount equal to the product of (1) the sum of their (a) highest annual base salary paid prior to their date of termination and (b) highest annual bonus paid or payable for any of the three years prior to the date of termination, and (2) the lesser of (i) two or (ii) the number of days remaining in the term of their employment agreement divided by 360. The amount provided in the table assumes for each executive a termination date of December 31, 2013, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $5,200,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $5,000,000 for Mr. Pefanis.

The employment agreements between GP LLC and Messrs. Armstrong and Pefanis define cause as (i) willfully engaging in gross misconduct, or (ii) conviction of a felony involving moral turpitude. Notwithstanding, no act, or failure to act, on their part is willful unless done, or omitted to be done, not in good faith and without reasonable belief that such act or omission was in the best interest of GP LLC or otherwise likely to result in no material injury to GP LLC. However, neither Mr. Armstrong nor Mr. Pefanis will be deemed to have been terminated for cause unless and until there is delivered to them a copy of a resolution of the board of directors of GP LLC at a meeting held for that purpose (after reasonable notice and an opportunity to be heard), finding that Mr. Armstrong or Mr. Pefanis, as applicable, was guilty of the conduct described above, and specifying the basis for that finding. If Mr. Armstrong or Mr. Pefanis were terminated for cause, GP LLC would be obligated to pay base salary through the date of termination, with no other payment obligations triggered by the termination under the employment agreement or other employment arrangement.

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

(2) Pursuant to their employment agreements, if Messrs. Armstrong and Pefanis terminate their employment with GP LLC within three (3) months of a change in control (as defined below), they are entitled to a lump-sum payment in an amount equal to the product of (i) three and (ii) the sum of (a) their highest annual base salary previously paid to them and (b) their highest annual bonus paid or payable for any of the three years prior to the date of such termination. The amount provided in the table assumes a change in control and termination date of December 31, 2013, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $5,200,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $5,000,000 for Mr. Pefanis.

Change in control was originally defined in their employment agreements to mean (i) the acquisition by a person or group (other than Vulcan Energy or a wholly owned subsidiary thereof) of beneficial ownership, directly or indirectly, of 50% or more of the membership interest of GP LLC or (ii) the owners of the membership interests of GP LLC on June 30, 2001 ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of GP LLC.

In August 2005, Vulcan Energy increased its interest in GP LLC from approximately 44% to greater than 50%. The consummation of the transaction constituted a change in control under the employment agreements with Messrs. Armstrong and Pefanis. However, Messrs. Armstrong and Pefanis entered into agreements with GP LLC waiving their rights to payments under their employment agreements in connection with the change in control, contingent on the execution and performance by Vulcan Energy of a voting agreement with GP LLC that restricted certain of Vulcan s voting rights. The December 2010 sale

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by Vulcan Energy of its interest in GP LLC also constituted a change in control under the employment agreements and resulted in the termination of the voting agreement. Messrs. Armstrong and Pefanis executed new agreements waiving their rights to payments under their employment agreements with respect to the December 2010 transaction and voting agreement termination.

The initial public offering of PAGP and certain related transactions also would have constituted a change in control under the employment agreements, which would have allowed Messrs. Armstrong and Pefanis to terminate their employment and become entitled to certain separation benefits. Messrs. Armstrong and Pefanis executed agreements waiving their rights to terminate employment and receive such benefits. In connection with such waiver, the definition of Change in Control in the employment agreements was also modified to mean, and will be deemed to occur upon, one or more of the following events: (i) any person (other than PAGP or its wholly owned subsidiaries), including any partnership, limited partnership, syndicate or other group deemed a person for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becomes the beneficial owner, directly or indirectly, of 50% or more of the membership interest in GP LLC or 50% or more of the outstanding limited partnership interests of PAGP; (ii) any person (other than PAGP or its wholly owned subsidiaries), including any partnership, limited partnership, syndicate or other group deemed a person for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becomes the beneficial owner, directly or indirectly, of 50% or more of the membership interest in PAA GP Holdings LLC; (iii) PAGP ceases to beneficially own, directly or indirectly, more than 50% of the membership interest in GP LLC; (iv) KAFU Holdings, L.P. and its affiliates, Lynx Holdings I, LLC and its affiliates, Oxy Holding Company (Pipeline), Inc. and its affiliates, Mark Strome and his affiliates, Windy, LLC and its affiliates, PAA Management, L.P. and its affiliates, PAGP and its affiliates, and various individual investors (collectively, the Owner Affiliates), cease to beneficially own, directly or indirectly, more than 50% of the membership interest in PAA GP Holdings LLC; or (v) there has been a direct or indirect transfer, sale, exchange or other disposition in a single transaction or series of transactions (whether by merger or otherwise) of all or substantially all of the assets of PAGP or PAA to one or more persons who are not affiliates of PAGP (third party or parties), other than a transaction in which the Owner Affiliates continue to beneficially own, directly or indirectly, more than 50% of the issued and outstanding voting securities of such third party or parties immediately following such transaction.

(3) The letters evidencing phantom unit grants to PAA s Named Executive Officers in 2010 and 2013 provide that in the event of their death or disability (as defined below), all of their then outstanding phantom units and associated DERs will be deemed nonforfeitable, and (i) any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would vest on the next following distribution date and (ii) the remaining unvested outstanding phantom units will vest on the distribution date on which the vesting criteria is met. For this purpose disability means a physical or mental infirmity that impairs the ability substantially to perform duties for a period of eighteen (18) months or that PAA s general partner otherwise determines constitutes a disability.

Assuming death or disability occurred on December 31, 2013, all of the 2010 phantom unit grants and associated DERs and one-third of the 2013 phantom unit grants and associated DERs of PAA s Named Executive Officers would have become nonforfeitable effective as of December 31, 2013, and would vest on the February 2014 distribution date. For the 2013 grants, any units not vested by August 2019 would expire. That portion of the dollar value given that is attributable to PAA phantom units is based on the market value of PAA s common units on December 31, 2013 ($51.77 per unit) without discount for service period.

(4) Pursuant to the phantom unit grants to PAA s Named Executive Officers in 2010 and 2013, in the event their employment is terminated other than in connection with a change of control (as defined in footnote 5 below) or by reason of death, disability (as defined in footnote 3 above) or retirement, all of the phantom units and associated DERs (regardless of vesting) then outstanding under such phantom unit grants would automatically be forfeited as of the date of termination; provided, however, that if GP LLC terminated their employment other than for cause (as defined in footnote 5 below), any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would be deemed nonforfeitable and would vest on the next following distribution date. The dollar value amount

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provided assumes that PAA s Named Executive Officers were terminated without cause on December 31, 2013. As a result, all of the 2010 phantom unit grants and one-third of the 2013 phantom unit grants held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would be deemed nonforfeitable and would vest on the February 2014 distribution date. That portion of the dollar value given that is attributable to PAA phantom units is based on the market value of PAA s common units on December 31, 2013 ($51.77 per unit), without discount for service period. In addition to the foregoing, under Canadian law, Mr. Duckett could have a claim for additional payment if inadequate notice were given for a termination without cause.

Under the waiver signed in 2010 by Mr. Armstrong and Mr. Pefanis (see footnote 2 above), upon a termination of employment by GP LLC without cause or by the executive for good reason (in each case as defined in the relevant employment agreement) all of the executive s outstanding awards under the 2005 Long-Term Incentive Plan would immediately vest.

(5) The letters evidencing the phantom unit grants to PAA s Named Executive Officers in 2010 and 2013 provide that in the event of a change in status (as defined below), all of the then outstanding phantom units and associated DERs will be deemed nonforfeitable, and such phantom units will vest in full (i.e., the phantom units will become payable in the form of one common unit per phantom unit) upon the next following distribution date. Assuming the change in status occurred on December 31, 2013, all outstanding phantom units and the associated DERs would have become nonforfeitable as of December 31, 2013, and such phantom units would vest on the February 2014 distribution date. That portion of the dollar value given that is attributable to PAA phantom units is based on the market value of PAA s common units on December 31, 2013 ($51.77 per unit), without discount for service period.

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

The phrase change of control means, and is deemed to have occurred upon the occurrence of, one or more of the following events: (i) GP LLC ceasing to be the general partner of PAA s general partner; (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of PAA or GP LLC to any person and/or its affiliates, other than to PAA or GP LLC, including any employee benefit plan thereof; (iii) the consolidation, reorganization, merger, or any other similar transaction involving (A) a person other than PAA or GP LLC and (B) PAA, GP LLC or both; (iv) the persons who own membership interests in GP LLC as of the grant date ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of GP LLC; or (v) any person, including any partnership, limited partnership, syndicate or other group deemed a person for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becoming the beneficial owner, directly or indirectly, of more than 49.9% of the membership interest in GP LLC. Notwithstanding the definition of change of control, no change of control is deemed to have occurred in connection with a restructuring or reorganization related to the securitization and sale to the public of direct or indirect equity interests in the general partner if (x) GP LLC retains direct or indirect control over the general partner and (y) the current members of GP LLC continue to own more than 50% of the member interest in GP LLC. The initial public offering of PAGP did not constitute a change of control under the phantom unit grant letters. The term cause means (i) the failure to perform the duties and responsibilities of a position at an acceptable level as reasonably determined in good faith by the CEO of GP LLC (or by the GP LLC Board in the case of the CEO), or (ii) the violation of GP LLC s Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described in writing.

(6) Pursuant to their employment agreements with GP LLC, if Messrs. Armstrong or Pefanis are terminated other than (i) for cause (as defined in footnote 1 above), (ii) by reason of death or (iii) by resignation

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(unless such resignation is due to a disability or for good reason (each as defined in footnote 1 above)), then they are entitled to continue to participate, for a period which is the lesser of two years from the date of termination or the remaining term of the employment agreement, in such health and accident plans or arrangements as are made available by GP LLC to its executive officers generally. The amounts provided in the table assume a termination date of December 31, 2013.

(7) Pursuant to their employment agreements, Messrs. Armstrong and Pefanis will be reimbursed for any excise tax due under Section 4999 of the Code as a result of compensation (parachute) payments made under their respective employment agreements. The values provided for this benefit assume that Messrs. Armstrong and Pefanis were terminated in connection with a change in control effective as of December 31, 2013.

(8) Pursuant to the AAP Management Unit grant agreements of each of PAA s Named Executive Officers, to encourage retention following the achievement of applicable performance benchmarks, AAP retained a call right to purchase any earned AAP Management Units for an amount equal to 75% of fair market value (which is referred to in the AAP Management Unit grant agreements as the Call Value as defined below) of such AAP Management Units, which call right is exercisable upon the termination of such Named Executive Officer s employment with GP LLC and its affiliates prior to January 1, 2016; provided, however, that such call right is not applicable in the case of the termination of such Named Executive Officer s employment without cause (defined below) or in the event of a resignation by such Named Executive Officer with good reason (defined below). In either such event, or if such Named Executive Officer remains employed past December 31, 2015, any earned AAP Management Units are no longer subject to the call right and are deemed to have vested. As of December 31, 2013, 100% of the AAP Management Units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned, but all of such AAP Management Units remained subject to AAP s call right. Assuming a termination of employment without cause or for good reason on December 31, 2013, all of the AAP Management Units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would become vested and would no longer be subject to the call right. Because the call right provides for a discounted purchase price equal to 75% of fair market value, in such event the applicable Named Executive Officer would benefit by virtue of the fact that such officer s AAP Management Units could no longer be purchased by AAP at a 25% discount. The value reflected in the table above represents the implied value of such benefit to the applicable Named Executive Officer, calculated as of December 31, 2013 by (i) assuming that such officer s AAP Management Units are converted into AAP Class A units based on the December 31, 2013 conversion factor of approximately 0.90 AAP units and PAGP Class B shares for each AAP Management Unit, (ii) assuming the exchange of the resulting AAP units and PAGP Class B shares for PAGP Class A shares on a one-for-one basis, and (iii) multiplying such resulting number of PAGP Class A shares by an amount equal to 25% of the closing market price ($26.77) of PAGP s Class A shares at December 31, 2013 (the last trading day of the fiscal year). The entire economic burden of the AAP Management Units is borne solely by AAP.

Cause is defined in the AAP Management Unit grant agreements as (i) a finding by the board of GP LLC that the executive has substantially failed to perform the duties and responsibilities of his position at an acceptable level and after written notice specifying such failure in detail and after a reasonable period under the circumstances (determined by the board in good faith) such failure has continued without full correction by the executive, (ii) the executive s conviction of or guilty plea to the committing of an act or acts constituting a felony under the laws of the United States or any state thereof or any misdemeanor involving moral turpitude, or (iii) any action by the executive involving personal dishonesty, theft or fraud in connection with executive s duties as an employee of GP LLC or its affiliates.

Good Reason is defined in the AAP Management Unit grant agreements as (i) any material breach by AAP of executive s AAP Management Unit grant agreement, (ii) the failure of any successor of AAP to assume executive s AAP Management Unit grant agreement, or (iii) any material overall reduction the executive s authority, responsibilities or duties.

Call Value is defined in the AAP Management Unit grant agreements as the product of the applicable conversion factor and the closing sales price of the PAGP Class A shares on the applicable date.

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(9) Pursuant to the AAP Management Unit grant agreements, upon the occurrence of a Change in Control, any earned AAP Management Units (and any AAP Management Units that will become earned in less than 180 days) become vested units and, to the extent any AAP Management Units remain unearned, an incremental 25% of the number of AAP Management Units originally granted becomes vested. As of December 31, 2013, 100% of the AAP Management Units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned. Accordingly, assuming a Change in Control on December 31, 2013, all of the AAP Management Units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would become vested and would no longer be subject to the call right. Because the call right provides for a discounted purchase price equal to 75% of fair market value as described above, the applicable Named Executive Officer would benefit from a Change in Control by virtue of the fact that such officer s AAP Management Units could no longer be purchased by AAP at a 25% discount. The value reflected in the table above represents the implied value of such benefit to the applicable Named Executive Officer, calculated as of December 31, 2013 by (i) assuming that such officer s AAP Management Units are converted into AAP units based on the December 31, 2013 conversion factor of approximately 0.90 AAP units and PAGP Class B shares for each AAP Management Unit, (ii) assuming the exchange of the resulting AAP units and PAGP Class B shares for PAGP Class A shares on a one-for-one basis, and (iii) multiplying such resulting number of PAGP Class A shares by an amount equal to 25% of the closing market price ($26.77) of PAGP s Class A shares at December 31, 2013 (the last trading day of the fiscal year). The entire economic burden of the AAP Management Units is borne solely by AAP.

Change in Control means the determination by the Board that one of the following events has occurred: (i) the Persons who own member interests in PAA GP Holdings, LLC immediately following the closing of the GP IPO, including PAGP, and the respective Affiliates of such Persons (such owners and Affiliates being referred to as the Owner Affiliates), cease to own directly or indirectly at least 50% of the membership interests of such entity; (ii) (x) a person or group other than the Owner Affiliates becomes the beneficial owner directly or indirectly of 25% or more of the member interest in the general partner of PAGP, and (y) the member interest beneficially owned by such person or group exceeds the aggregate member interest in the general partner of PAGP beneficially owned, directly or indirectly, by the Owner Affiliates; or (iii) a direct or indirect transfer, sale, exchange or other disposition in a single transaction or series of transaction (whether by merger or otherwise) of all or substantially all of the assets of PAGP or PAA to one or more Persons who are not Affiliates of PAGP (third party or parties), other than a transaction in which the Owner Affiliates continues to beneficially own, directly or indirectly, more than 50% of the issued and outstanding voting securities of such third party or parties immediately following such transaction.

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

Confidentiality, Non-Compete and Non-Solicitation Arrangements

Pursuant to his employment agreement, Mr. Armstrong has agreed to maintain the confidentiality of PAA information for a period of five years after the termination of his employment. Mr. Pefanis has agreed to a similar restriction for a period of one year following the termination of his employment. Mr. Duckett has agreed to maintain confidentiality following termination of his employment for a period of two years with respect to customer lists. He has also agreed not to compete in a specified geographic area for a period of two years after termination of his employment. Mr. vonBerg has agreed to maintain confidentiality and not to solicit customers for a period of one year following termination of his employment.

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Compensation of GP LLC s Directors

The following table sets forth a summary of the compensation paid to each person who served as a non-employee director of GP LLC in 2013:

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($) (1)	Total ($)
Everardo Goyanes	75,000	265,700	340,700
Gary R. Petersen	45,000	132,850	177,850
John T. Raymond	45,000	132,850	177,850
Robert V. Sinnott	47,000	132,850	179,850
Vicky Sutil (2)	45,000	n/a	45,000
J. Taft Symonds	62,000	265,700	327,700
Christopher M. Temple	60,000	265,700	325,700

(1) The dollar value of LTIPs granted during 2013 is based on the grant date fair value computed in accordance with FASB ASC Topic 718. See Note 15 to our Consolidated Financial Statements for additional discussion regarding the calculation of grant date fair values. In connection with the August 2013 vesting of director LTIP awards, Messrs. Goyanes, Symonds and Temple each were granted 5,000 units, and Messrs. Petersen, Raymond and Sinnott each were granted 2,500 units by virtue of the automatic re-grant feature of the vested awards. Upon vesting of the director LTIP awards in August 2013 (other than the incremental audit committee awards), a cash payment of $107,688 was made to Oxy as directed by Ms. Sutil. Such cash payment was based on the unit value of Mr. Sinnott s award on the previous year s vesting date. As of December 31, 2013, the number of outstanding LTIPs held by GP LLC s directors was as follows: Goyanes - 20,000 ; Petersen - 10,000; Raymond - 10,000; Sinnott - 10,000; Symonds - 20,000; and Temple - 20,000.

(2) Ms. Sutil s compensation is assigned to Oxy.

Each director of GP LLC who is not an employee of GP LLC is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the GP LLC board (including, without limitation, reimbursement for continuing education expenses). Each GP LLC non-employee director is currently paid an annual retainer fee of $45,000. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. In addition to the annual retainer, each committee chairman (other than the chairman of the GP LLC audit committee) receives $2,000 annually. The chairman of the GP LLC audit committee receives $30,000 annually, and the other members of the GP LLC audit committee receive $15,000 annually, in each case, in addition to the annual retainer. During 2013, Messrs. Sinnott, Goyanes and Symonds served as chairmen of the GP LLC compensation, audit and governance committees, respectively.

GP LLC s non-employee directors receive LTIP awards or cash equivalent awards as part of their compensation. The LTIP awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The awards have associated distribution equivalent rights that are payable quarterly. The three non-employee directors who serve on the audit committee (Messrs. Goyanes, Symonds and Temple) each have outstanding a grant of 20,000 units (vesting 5,000 units per year). Messrs. Petersen, Raymond and Sinnott each have outstanding a grant of 10,000 units (vesting 2,500 units per year). Upon vesting of the director LTIPs (other than the incremental audit committee awards), a cash payment will be made to Oxy as directed by the Oxy designee. Such cash payment is based on the unit value of Mr. Sinnott s award on the previous year s vesting date.

All LTIP awards held by a GP LLC director vest in full upon the next following distribution date after the death or disability (as determined in good faith by the board) of the director. For audit committee grants, the awards also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the board of directors or is not reelected to the board of directors, unless such removal or failure to reelect is for good cause, as defined in the letter granting the units.

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Compensation of PAA GP Holdings LLC Directors

Messrs. Raymond and Sinnott and Ms. Sutil serve on both our general partner s board of directors and GP LLC s board of directors. They are compensated by GP LLC and do not receive additional compensation for service on our general partner s board of directors. Mr. Armstrong is otherwise compensated for his services as an employee by GP LLC and receives no separate compensation for his services as a director of our general partner.

Messrs. Burk and Shackouls each receive an annual retainer of $40,000 for service on our general partner s board and the audit committee. Messrs. Burk and Shackouls each also received initial equity compensation in the form of an LTIP award for 32,000 phantom Class A shares that, subject to continued service as a director, vests in 25% increments over a four-year period and includes an automatic re-grant equal to 25% of the initial award.

Mr. Goyanes serves on our general partner s board as well as on GP LLC s board and also serves as chairman of the audit committee of both boards. Mr. Goyanes is compensated by GP LLC for his service as a director and chairman of the audit committee of the GP LLC board. Mr. Goyanes does not receive any cash consideration for his service as a director and chairman of the audit committee of our general partner s board, but received initial equity compensation in the form of an LTIP award for 19,200 phantom Class A shares that, subject to continued service as a director, vests in 25% increments over a four-year period and includes an automatic re-grant equal to 25% of the initial award. Mr. Goyanes annual compensation represents roughly one-half of the value of the total annual compensation to be paid to each of Messrs. Burk and Shackouls.

The LTIP awards granted to Messrs. Burk, Goyanes and Shackouls also have associated distribution equivalent rights that are payable quarterly and entitle the holder to receive a cash payment for each phantom Class A share equal in amount to the distribution paid on our Class A shares. The LTIP awards held by Messrs. Burk, Goyanes and Shackouls vest in full upon the distribution date immediately following the date such director (i) dies or is determined by the board to be disabled, (ii) retires, or (iii) is removed from the board of directors or is not re-elected to the board of directors, unless such removal or failure to re-elect is for cause as defined in the limited liability company agreement of our general partner.

Each director will be indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

Reimbursement of Expenses of PAA s General Partner and its Affiliates

PAA does not pay its general partner a management fee, but it does reimburse its general partner for all direct and indirect costs of services provided to PAA, incurred on PAA s behalf, including the costs of employee, officer and director compensation (other than expenses related to the AAP Management Units) and benefits allocable to PAA, as well as all other expenses necessary or appropriate to the conduct of PAA s business, allocable to PAA. PAA records these costs on the accrual basis in the period in which PAA s general partner incurs them. PAA s partnership agreement provides that its general partner will determine the expenses that are allocable to PAA in any reasonable manner determined by its general partner in its sole discretion.

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Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters***

Plains GP Holdings, L.P.

The following tables set forth certain information regarding the beneficial ownership of our Class A shares and Class B shares as of February 15, 2014 by:

- each person who is known to us to beneficially own more than 5% of the Class A shares;
- each person who is known to us to beneficially own more than 5% of the Class B shares;
- the Named Executive Officers of our general partner;
- each of the directors of our general partner; and
- all of the directors and executive officers of our general partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more shareholders, as the case may be. Unless otherwise noted, the address of each beneficial owner named in the chart below is 333 Clay Street, Suite 1600, Houston, Texas 77002.

Name and Address of Beneficial Owner	Class A Shares Beneficially Owned (1)	Percentage of Class A Shares Beneficially Owned	Class B Shares Beneficially Owned (1) (2)	Percentage of Class B Shares Beneficially Owned (2)
Waddell & Reed Financial, Inc. (3) 6300 Lamar Avenue Overland Park, KS 66202	19,524,700	14.57%		
Goldman Sachs Asset Management (4) 200 West Street New York, NY 10282	10,862,719	8.10%		
Janus Capital Management LLC (5) 151 Detroit Street	7,109,560	5.30%		

Denver, CO 80206				
Oxy Holding Company (Pipeline), Inc. 10899 Wilshire Boulevard Los Angeles, CA 90024			148,830,161	28.82%
EMG Investment, LLC 811 Main, Suite 4200 Houston, TX 77002			121,516,879	23.53%
KAFU Holdings, L.P. & KAFU Holdings II, L.P. 1800 Avenue of the Stars, 3rd Floor Los Angeles, CA 90067			103,202,576	19.99%
Greg L. Armstrong (6)			15,034,008	2.91%
Harry N. Pefanis (7)			10,284,301	1.99%
Al Swanson (8)			3,533,895	*
W. David Duckett (9)			5,376,748	1.04%
John P. vonBerg (10)			4,248,112	*
Victor Burk				
Everardo Goyanes	45,000	*		
John T. Raymond (11)			129,993,681	25.17%
Bobby S. Shackouls				
Robert V. Sinnott (12)			103,202,576	19.99%
Vicky Sutil				
All directors and executive officers of our general partner as a group (16 persons) (13)(14)	45,000	*	281,986,695	54.61%

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* Less than 1%.

(1) Class A shares beneficially owned do not include any Class A shares issuable in connection with the exchange of any Class B shares, whether such Class B shares are currently outstanding or issuable following the conversion of any AAP Management Units. Although holders of our Class B shares have the right, at any time and from time to time, to immediately exchange (the Exchange Right) their Class B shares, together with a like number of AAP units and general partner units, for our Class A shares on a one-for-one basis, the fact that such Exchange Right may be settled in cash at AAP s option results in such Class A shares not being deemed to be beneficially owned by the holders of our Class B shares.

(2) If our Class A shares are publicly traded at any time after December 31, 2015, a holder of vested AAP Management Units will be entitled to exchange such AAP Management Units for Class B shares and a like number of AAP units based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and was approximately 0.91 AAP units (and Class B shares) for each AAP Management Unit as of February 15, 2014). Accordingly, figures presented for Class B shares beneficially owned and percentage of Class B shares beneficially owned are presented on a fully diluted basis and include Class B shares to be issued upon the exchange of all outstanding AAP Management Units based on such 0.91 conversion ratio.

(3) This information has been derived from a Schedule 13G filed with the SEC on February 7, 2014.

(4) This information has been derived from a Schedule 13G filed with the SEC on February 13, 2014.

(5) This information has been derived from a Schedule 13G filed with the SEC on February 14, 2014.

(6) Represents the number of Class B shares beneficially owned by Mr. Armstrong through his (i) direct and indirect ownership of an approximately 25.3% interest in PAA Management, L.P., which entity owns 21,835,922 Class B shares, and (ii) beneficial ownership of 9,516,715 AAP units and Class B shares, based on an assumed conversion ratio of 0.91 AAP units and Class B shares for each AAP Management Unit.

(7) Represents the number of Class B shares beneficially owned by Mr. Pefanis through his (i) direct and indirect ownership of an approximately 14.4% interest in PAA Management, L.P., which entity owns 21,835,922 Class B shares, and (ii) beneficial ownership of 7,137,537 AAP units and Class B shares, based on an assumed conversion ratio of 0.91 AAP units and Class B shares for each AAP Management Unit.

(8) Represents the number of Class B shares beneficially owned by Mr. Swanson through his (i) direct and indirect ownership of an approximately 5.3% interest in PAA Management, L.P., which entity owns 21,835,922 Class B shares, and (ii) beneficial ownership of 2,379,179 AAP units and Class B shares, based on an assumed conversion ratio of 0.91 AAP units and Class B shares for each AAP Management Unit.

(9) Represents the number of Class B shares beneficially owned by Mr. Duckett through his (i) direct and indirect ownership of an approximately 6.1% interest in PAA Management, L.P., which entity owns 21,835,922 Class B shares, and (ii) beneficial ownership of 4,044,604 AAP units and Class B shares, based on an assumed conversion ratio of 0.91 AAP units and Class B shares for each AAP Management Unit.

(10) Represents the number of Class B shares beneficially owned by Mr. vonBerg through his (i) direct and indirect ownership of an approximately 4.2% interest in PAA Management, L.P., which entity owns 21,835,922 Class B shares, and (ii) beneficial ownership of 3,330,850 AAP units and Class B shares, based on an assumed conversion ratio of 0.91 AAP units and Class B shares for each AAP Management Unit.

(11) Mr. Raymond is (i) the sole member of the general partner of the manager of EMG Investment, LLC, which entity owns 121,516,879 Class B shares, and (ii) the sole member of Lynx Holdings I, LLC, which entity owns 8,476,802 Class B shares. As such, Mr. Raymond has sole voting and dispositive power over the Class B shares owned by each of EMG Investment, LLC and Lynx Holdings I, LLC. Mr. Raymond disclaims any deemed beneficial ownership of the interests owned by EMG Investment, LLC beyond his pecuniary interest therein.

(12) Mr. Sinnott has shared voting and dispositive power over the Class B shares owned by KAFU Holdings, L.P. (KAFU), which entity owns 96,407,031 Class B shares, and KAFU Holdings II, L.P. (KAFU II), which

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entity owns 6,795,545 Class B shares. Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU and KAFU II beyond his pecuniary interest therein.

(13) The executive officers of our general partner as a group directly and indirectly own (i) an approximately 65.4% interest in PAA Management, L.P., which entity owns 21,835,922 Class B shares, and (ii) 34,498,093 AAP units and Class B shares based on an assumed conversion ratio of 0.91 AAP units and Class B shares for each AAP Management Unit. Amount shown in table represents the number of Class B shares beneficially owned by this group by virtue of such interests.

(14) As of February 15, 2014, no Class A shares or Class B shares were pledged by directors or Named Executive Officers.

Beneficial Ownership of Plains AAP, L.P.

The following table sets forth the percentage ownership of each of the Class A limited partners of AAP and the resulting economic interest of each such limited partner and the holders of the AAP Management Units as a group, in each case as of February 15, 2014:

Name of Owner and Address (in the case of Owners of more than 5%)	**Percentage Ownership of Plains AAP, L.P. Class A LP Interest**	**Economic Interest in Plains AAP, L.P. (1)**
Plains GP Holdings, L.P. 333 Clay Street, Suite 1600 Houston, TX 77002	22.12%	20.61%
Oxy Holding Company (Pipeline), Inc. 10889 Wilshire Boulevard Los Angeles, CA 90024	24.56%	22.88%
EMG Investment, LLC 811 Main, Suite 4200 Houston, TX 77002	20.05%	18.68%
KAFU Holdings, L.P. and Affiliates 1800 Avenue of the Stars, 3rd Floor Los Angeles, CA 90067	18.54%	17.27%
KA First Reserve XII, LLC	2.48%	2.32%
PAA Management, L.P. **(2)**	3.60%	3.36%
Strome PAA, L.P. and Affiliate	3.71%	3.46%
Windy, L.L.C.	3.00%	2.79%
Lynx Holdings I, LLC	1.40%	1.30%
Various Individual Investors	0.54%	0.50%
AAP Management Unitholders**(3)**		6.83%

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(1) AAP owns a 100% member interest in PAA GP LLC, which owns PAA s 2% general partner interest. AAP has pledged its member interest, as well as its interest in PAA s incentive distribution rights, as security for its obligations under the Second Amended and

Restated Credit Agreement dated as of September 26, 2013 among AAP, Citibank, N.A. and the lenders party thereto (the Plains AAP Credit Agreement). A default by AAP under the Plains AAP Credit Agreement could result in a change in control of PAA s general partner.

(2) PAA Management, L.P. is owned entirely by certain current and former members of PAA senior management, including Messrs. Armstrong (approximately 25%), Pefanis (approximately 14%), Duckett (approximately 6%), vonBerg (approximately 4%) and Swanson (approximately 5%). Other than Mr. Armstrong, none of our directors own any interest in PAA Management, L.P. Executive officers of PAA as a group own approximately 65% of PAA Management, L.P. Mr. Armstrong disclaims any beneficial

ownership of the general partner interest except to the extent of his ownership interest in PAA Management, L.P.

(3) Represents profits interest in AAP in the form of AAP Management Units owned by certain members of PAA management. Named Executive Officers and executive officers as a group own the following AAP Management Units: Mr. Armstrong 10,425,791; Mr. Pefanis 7,819,344; Mr. Swanson 2,606,448; Mr. Duckett 4,430,961; Mr. vonBerg 3,649,027, and executive officers as a group 37,793,493. None of our directors own any AAP Management Units.

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Equity Compensation Plan Information

The following table sets forth certain information with respect to our equity compensation plan as of December 31, 2013. For a description, see Item 13. Certain Relationships and Related Transactions, and Director Independence Plains GP Holdings, L.P. Long Term Incentive Plan.

Plan Category	Number of Shares to be Issued upon Exercise/Vesting of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Shares Remaining Available for Future Issuance under Equity Compensation Plans (c)
Equity compensation plans approved by shareholders:			
Long Term Incentive Plan	N/A(1)	N/A	10,000,000(1)
Equity compensation plans not approved by shareholders	N/A	N/A	N/A

(1) The Plains GP Holdings, L.P. Long Term Incentive Plan (the LTIP) was adopted by our general partner in connection with our initial public offering in October 2013. The LTIP contemplates the issuance or delivery of up to 10,000,000 Class A shares to satisfy awards under the LTIP. As of December 31, 2013, no grants or awards had been issued or were outstanding under the LTIP.

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

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

Our General Partner

Our general partner manages our operations and activities. We and our general partner have no employees. All of our officers and other personnel necessary for our business to function (the the extent not outsourced) are employed by GP LLC. As a result, the Administrative Agreement provides for AAP s payment of an annual fee to GP LLC for general and administrative services. See   Related Party Transactions Administrative Agreement for further information. AAP also reimburses our general partner and its affiliates for expenses incurred in managing and operating us and our general partner. AAP also reimburses GP LLC for expenses incurred (i) on our behalf, (ii) on behalf of our general partner, or (iii) for any other purpose related to our business and activities or those of our general partner. AAP also reimburses our general partner for any additional expenses incurred on our behalf or to maintain our legal existence and good standing.

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. We own a portion of the membership interest in our general partner.

Plains GP Holdings, L.P. Long Term Incentive Plan

In connection with our initial public offering, our general partner adopted the Plains GP Holdings, L.P. Long Term Incentive Plan (the   LTIP) on our behalf for (i) the employees of our general partner and its affiliates who perform services for us and (ii) the non-employee directors of our general partner. Awards that may be granted under the LTIP include restricted shares, phantom shares, options and share appreciation rights. The LTIP limits the number of shares that may be delivered pursuant to awards to 10,000,000 Class A shares (subject to any adjustment due to recapitalization, reorganization or a similar event permitted under the LTIP). Shares (other than restricted shares) that are forfeited or withheld to satisfy exercise price or tax withholding obligations are available for delivery pursuant to other awards. As of December 31, 2013, no grants or awards had been issued or were outstanding under the LTIP; however, three of our directors received LTIP awards for an aggregate of 83,200 phantom Class A shares in February 2014.

The LTIP is administered by the board of directors of our general partner. The board of directors of our general partner has the right to terminate or amend the LTIP or any part of the LTIP from time to time, including increasing the number of shares that may be granted, subject to shareholder approval as may be required by the exchange upon which the Class A shares are listed at that time, if any. No change may be made in any outstanding grant that would materially reduce the benefits of the participant without the consent of the participant. The LTIP will expire upon the earlier of the termination of the LTIP by the board of directors of our general partner or the date that no shares remain available under the LTIP for awards. Upon termination of the LTIP, awards then outstanding will continue pursuant to the terms of their grants.

Class A shares to be delivered in settlement of awards under the LTIP may be newly issued Class A shares, Class A shares acquired in the open market, Class A shares acquired from any other person, or any combination of the foregoing.

Awards

Restricted Shares. A restricted share is a Class A share that vests over a period of time and that during such time is subject to forfeiture. The board of directors will determine the period over which restricted shares granted to participants will vest. The board of directors, in its discretion, may base its determination upon the achievement of performance metrics. Distributions made on restricted shares may be subjected to the same vesting provisions as the restricted share. If a grantee s employment or membership on the board of directors terminates for any reason, the grantee s restricted shares will be automatically forfeited unless, and to the extent, the board of directors or the terms of the award agreement provide otherwise.

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We intend the restricted shares under the LTIP to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our Class A shares. Therefore, participants will not pay any consideration for the Class A shares they receive, and we will receive no remuneration for the shares.

Phantom Shares. A phantom share entitles the grantee to receive a Class A share upon the vesting of the phantom share or, in the discretion of the board of directors, cash equivalent to the value of a Class A share. The board of directors will determine the period over which phantom shares granted to participants will vest. The board of directors, in its discretion, may base its determination upon the achievement of performance metrics. If a grantee s employment or membership on the board of directors terminates for any reason, the grantee s phantom shares will be automatically forfeited unless, and to the extent, the board of directors or the terms of the award agreement provide otherwise.

The board of directors, in its discretion, may grant distribution equivalent rights, which we refer to as DERs, with respect to a phantom share. DERs entitle the grantee to receive an amount in cash equal to the cash distributions made on a Class A share during the period the related award is outstanding. The board of directors will establish whether the DERs are paid currently, when the tandem phantom share vests or on some other basis.

We intend the issuance of any Class A shares upon vesting of the phantom shares under the LTIP to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our Class A shares. Therefore, plan participants will not pay any consideration for the Class A shares they receive, and we will receive no remuneration for the shares.

Options. An option provides a participant with the option to acquire Class A shares at a specified price. The exercise price of each option granted under the LTIP will be stated in the option agreement and may vary between participants; provided, however, that the exercise price for an option must not be less than 100% of the fair market value per Class A share as of the date of grant of the option. Options may be exercised in the manner and at such times as the board of directors determines for each option. The board of directors will determine the methods and form of payment for the exercise price of an option and the methods and forms in which Class A shares will be delivered to a participant. The board of directors, in its discretion, may grant DERs with respect to an option.

Share Appreciation Rights. A share appreciation right is an award that, upon exercise, entitles the holder to receive the excess, if any, of the fair market value of a Class A share on the exercise date over the grant price of the share appreciation right. The excess may be paid in cash and/or in Class A shares, as determined by the board of directors in its discretion. The board of directors will have the authority to determine to whom share appreciation rights will be granted, the number of Class A shares to be covered by each grant, and the conditions and limitations applicable to the exercise of the share appreciation right. The grant price per share appreciation right will be determined by the board of directors at the time the share appreciation right is granted, but each share appreciation right must have an exercise price that is not less than the fair market value of the Class A shares on the date of grant. The board of directors will determine the time or times at which a share appreciation right may be exercised in whole or in part. Unless otherwise waived by the board of directors, or set forth in an award agreement, outstanding share appreciation rights awarded to a participant will be automatically forfeited upon a termination of the individual s employment or membership on the board of directors terminates for any reason. The board of directors, in its discretion, may grant DERs with respect to a share appreciation right.

Other LTIP Provisions

Tax Withholding. Unless other arrangements are made, our general partner and its affiliates will be authorized to withhold from any award, from any payment due under any award, or from any compensation or other amount owing to a participant the amount (in cash, shares, shares that would otherwise be issued pursuant to such award, or other property) of any applicable taxes payable with respect to the grant of an award, its settlement, its exercise, the lapse of restrictions applicable to an award or in connection with any payment relating to an award or the transfer of an award and to take such other actions as may be necessary to satisfy the withholding obligations with respect to an award.

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Anti-Dilution Adjustments. Upon the occurrence of any equity restructuring event that could result in an additional compensation expense under Financial Accounting Standards Board Accounting Standards Codification Topic 718 (FASB ASC Topic 718) if adjustments to awards with respect to such event were discretionary, the board of directors will equitably adjust the number and type of shares covered by each outstanding award and the terms and conditions of such award to equitably reflect the restructuring event, and the board of directors will adjust the number and type of shares with respect to which future awards may be granted. With respect to a similar event that would not result in a FASB ASC Topic 718 accounting charge if adjustment to awards were discretionary, the board of directors shall have complete discretion to adjust awards in the manner it deems appropriate.

Change of Control. If specifically provided in an award agreement, upon a change of control (as defined in the award agreement), the award may automatically vest and be payable or become exercisable in full, as the case may be.

Transferability of Awards. Options and share appreciation rights are only exercisable by the participant during the participant s lifetime, or by the person to whom the participant s rights pass by will or the laws of descent and distribution. No award or right granted under the LTIP may be assigned, alienated, pledged, attached, sold or otherwise transferred or encumbered and any such purported transfer shall be void and unenforceable. Notwithstanding the foregoing, the board of directors may, in its discretion, allow a participant to transfer an option or a share appreciation right without consideration to an immediate family member or a related family trust, limited partnership, or similar entity on the terms and conditions established by the board of directors from time to time.

AAP Management Units

In August 2007, the owners of AAP authorized the creation and issuance of AAP Management Units and authorized the compensation committee of GP LLC to issue grants of AAP Management Units to create long-term incentives for PAA s management. The entire economic burden of the AAP Management Units, which are equity classified, is borne solely by AAP. PAA is not obligated to reimburse AAP for any costs attributable to the AAP Management Units. The amount of cash available for distribution by AAP to us will be reduced by amounts to which the AAP Management Units are entitled, which will reduce the cash available for distribution to our Class A shareholders. Each AAP Management Unit represents a profits interest in AAP, 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 AAP s asset values. Up to 52,125,935 AAP Management Units are authorized for issuance. As of December 31, 2013, 48,642,830 AAP Management Units were issued and outstanding, which, based on the conversion ratio of approximately 0.90 AAP units for each AAP Management Unit as of December 31, 2013, would equate to 43,970,227 AAP units.

The outstanding AAP Management Units are subject to restrictions on transfer and generally become earned (entitled to receive a portion of the distributions that would otherwise be paid to PAA s general partner) in percentage increments when the annualized quarterly distributions on our common units equal or exceed certain thresholds. Upon achievement of these performance thresholds (or, in some cases, within six months thereafter), the AAP Management Units will be entitled to their proportionate share of all quarterly cash distributions made by AAP in excess of $11 million per quarter (as adjusted for debt service costs and excluding special distributions funded by debt). Assuming all authorized AAP Management Units are issued, the maximum participation would be approximately 8% of the amount in excess of $11 million per quarter, as adjusted. As of February 14, 2014, approximately 98% of the outstanding AAP Management Units had been earned or will be earned within 180 days. The remaining AAP Management Units will be earned in 25% increments 180 days after payment of annualized quarterly distributions of $2.55, $2.70 and $2.85 per unit, respectively.

To encourage retention following achievement of these performance benchmarks, AAP retained a call right to purchase any earned AAP Management Units at a discount to fair market value that is exercisable upon the termination of a holder s employment with GP LLC and its affiliates (other than a termination without cause or by the employee for good reason) prior to certain stated dates. If a holder of an AAP Management Unit remains employed past such designated date (or prior to such date is terminated without cause or quits for good reason), any earned units are no longer subject to the call right and are deemed to have vested. The applicable designated dates for the various AAP Management Unit grants range from January 1, 2016 for AAP Management Units granted in 2007 to January 1, 2021 for AAP Management Units granted in 2013. If the call right of AAP becomes exercisable, in order to encourage retention, the size of the discount to fair market value reflected in the purchase price decreases over time pursuant to a formula set forth in each AAP Management Unit grant agreement. AAP Management Unit grants also provide that all earned AAP Management Units and a portion of any unearned and unvested AAP Management Units will vest upon a change of control. All earned AAP Management Units will also vest if AAP elects not to timely exercise its call right.

If at any time after December 31, 2015 our Class A shares are publicly traded, each vested AAP Management Unit may be converted into AAP units and a like number of PAGP Class B shares based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and was approximately 0.91 AAP units and PAGP Class B shares for each AAP Management Unit as of February 15, 2014). Following any such conversion, the resulting AAP units and PAGP Class B shares are exchangeable for PAGP Class A shares on a one-for-one basis as provided in the PAGP limited partnership agreement.

Related Party Transactions

Administrative Agreement

In connection with the closing of our initial public offering, we entered into an administrative agreement (the Administrative Agreement) with PAA, our general partner, AAP, PAA GP LLC and GP LLC to address, among other things, potential conflicts with respect to business opportunities that may arise among us, our general partner, AAP, PAA, PAA GP LLC and GP LLC. The agreement provides that if any business opportunity is presented to us, our general partner, AAP, PAA, PAA GP LLC or GP LLC, then PAA will have the first right to pursue such business opportunity. We will have the right to pursue and/or participate in such business opportunity if invited to do so by PAA, or if PAA abandons the business opportunity and GP LLC so notifies our general partner.

Pursuant to the Administrative Agreement, all of our officers and other personnel necessary for our business to function (to the extent not out-sourced) are employed by GP LLC, and AAP pays GP LLC an annual fee for general and administrative services performed on our behalf. The initial fee is $1.5 million per year and is subject to adjustment on an annual basis, beginning on January 1, 2015, based on the Consumer Price Index. The fee is also subject to adjustment if a material event occurs that impacts the general and administrative services provided to us, such as acquisitions, entering into new lines of business or changes in laws, regulations, listing requirements or accounting rules.

In addition, the Administrative Agreement provides that any direct expenses incurred by us, our general partner and AAP (other than income taxes payable by us) are borne by AAP. These direct expenses include costs related to (i) compensation for new directors, (ii) incremental director and officer liability insurance, (iii) listing on the NYSE, (iv) investor relations, (v) legal, (vi) tax and (vii) accounting.

In addition to the fee and expenses described above, the Administrative Agreement requires AAP to reimburse GP LLC for any additional expenses incurred by GP LLC and certain of its affiliates (i) on our behalf, (ii) on behalf of our general partner, or (iii) for any other purpose related to our business and activities or those of our general partner. AAP is also required to reimburse our general partner for any additional expenses incurred by it on our behalf or to maintain our legal existence and good standing. There is no limit on the amount of fees and expenses AAP may be required to pay to affiliates of our general partner on our behalf pursuant to the Administrative Agreement.

Pursuant to the Administrative Agreement, PAA has also granted us a license to use the names PAA and Plains and any associated or related marks.

Recapitalization

As of December 31, 2013, our sole assets consisted of (i) a 100% member interest in GP LLC, which holds a non-economic general partner interest in AAP, (ii) 133,833,637 AAP units (representing 22.1% of the limited partner interests in AAP, and an approximate 20.6% economic interest (including the dilutive effect of the AAP Management Units) in AAP, which directly or indirectly owns all of the IDRs and the 2% general partner interest in

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PAA), and (iii) 133,833,637 general partner units representing 22.1% of the membership interests in our general partner.

Prior to our initial public offering, the Legacy Owners directly or indirectly owned all of the ownership interests in AAP and GP LLC (other than the AAP Management Units). In connection with our initial public offering, including the partial exercise of the underwriters overallotment option, the following transactions were effected:

- The 1% general partner interest in AAP held by GP LLC was converted into a non-economic general partner interest and a limited partner interest in AAP represented by 6,500,000 AAP units. Such AAP units were distributed by GP LLC to the Legacy Owners;

- The Legacy Owners contributed their respective membership interests in GP LLC to our general partner in exchange for membership interests in our general partner, and our general partner contributed such interests in GP LLC to us in exchange for the continuation of its non-economic general partner interest in us. In exchange for these contributions, we issued (through our general partner) a total of 478,029,773 Class B shares to the Legacy Owners;

- Certain of the Legacy Owners (or in the case of EMG, certain members of EMG) sold to us (i) 132,382,094 AAP units (representing a 21.8% limited partnership interest, and an approximate 20.4% economic interest (including the dilutive effect of the AAP Management Units) in AAP) and (ii) an aggregate 21.8% of the membership interests in our general partner, in exchange for the right to receive an amount equal to the net proceeds of the offering, subject to adjustment for certain expenses as provided in the Contribution Agreement (described below).

- We issued 132,382,094 of our Class A shares to the public;

- The AAP limited partnership agreement was amended and restated to provide that (i) the number of AAP units held by us and the Legacy Owners would be adjusted so that the relative limited partner interests held by us and the Legacy Owners stay the same after increasing the number of AAP units we own so that it equals the number of Class A shares issued to the public, (ii) each Legacy Owner will have the right to exchange its AAP units and a like number of Class B shares and general partner units for Class A shares on a one-for-one basis, and (iii) each holder of AAP Management Units will receive, upon the conversion of any such AAP Management Units into AAP units and a like number of Class B shares, an associated right to exchange such AAP units and Class B shares for Class A shares on a one-for-one basis;

- We received, after deducting underwriting discounts and commissions and offering expenses payable by us, net proceeds of approximately $2.8 billion from the issuance and sale of 132,382,094 Class A shares, and distributed these proceeds to the Legacy Owners (or in the case of EMG, certain members of EMG) as described above; and

- We also entered into the Administrative Agreement.

In accordance with the AAP partnership agreement, holders of AAP Management Units are allocated gross income equal to the amount of any distributions paid with respect to such units and the remaining net profits and net losses of AAP are generally allocated to the other holders of AAP units on a pro rata basis in accordance with their relative number of AAP units held. Accordingly, net profits and losses of AAP are allocated 20.6% to us and 72.6% to the Legacy Owners. In addition, through our control of GP LLC, we have the right to determine when distributions will be made to the holders of AAP units and the amount of any such distributions. If we cause a distribution to be made, such distribution will, subject to certain limitations on the amount of distributions to be made with respect to AAP Management Units, be made to the holders of AAP units on a pro rata basis in accordance with their relative number of AAP units held.

Prior to the trigger date, GP LLC must remain the sole general partner of AAP, and may not withdraw, transfer its general partner interest or be replaced, unless the holders of two-thirds of the AAP units consent. In addition, no (i) entry into new material related party transactions, (ii) issuance of AAP securities to us or (iii) change in AAP s tax election may occur prior to the expiration of a 30-day notice period in favor of the holders of AAP units.

For purposes of any transfer or exchange of AAP units initially owned by the Legacy Owners and our Class B shares, the AAP partnership agreement, our general partner s limited liability company agreement and our partnership agreement contain provisions linking each such AAP unit with one of our Class B shares and a general partner unit. Our Class B shares and general partner units cannot be transferred without transferring an equal number of AAP units and vice versa.

The Legacy Owners and any permitted transferees of their AAP units each have the right to exchange (the Exchange Right) all or a portion of their AAP units into Class A shares at an exchange ratio of one Class A share for each AAP unit exchanged. The above Exchange Right may be exercised only if, simultaneously therewith, an equal number of our Class B shares and general partner units are transferred by the exercising party to us. We are obligated to facilitate such exchange through a contribution of Class A shares to AAP or alternatively we have the right to acquire the subject AAP units, Class B shares and general partner units directly from the AAP unitholder exercising the Exchange Right. At AAP s option, AAP may give the exchanging AAP unitholder cash in an amount equal to the market value of the Class A shares instead. Prior to the trigger date, no change to the one-for-one exchange ratio may be made without the prior approval of the holders of two-thirds of the AAP units, and only after the expiration of a 30-day notice period.

Additionally, if the Class A shares are publicly traded at any time after December 31, 2015, a holder of vested AAP Management Units will be entitled to exchange his or her AAP Management Units for AAP units and a like number of Class B shares based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and is approximately 0.91 AAP units for each AAP Management Unit as of February 15, 2014). Following any such exchange, the holder will have the Exchange Right for our Class A shares. Holders of AAP Management Units who exchange for AAP units and Class B shares will not receive general partner units and thus will not need to include any general partner units in a transfer or the exercise of their Exchange Right.

The above mechanisms are subject to customary conversion rate adjustments for equity splits, equity dividends and reclassifications.

In addition, pursuant to our partnership agreement and the AAP partnership agreement, our capital structure and the capital structure of AAP generally replicate one another and provide for customary antidilution mechanisms in order to maintain the one-for-one exchange ratio between the AAP units, Class B shares and general partner units, on the one hand, and our Class A shares, on the other hand.

Contribution Agreement

In connection with the closing of our initial public offering in October 2013, we, our general partner and the Legacy Owners entered into a contribution agreement (the Contribution Agreement) pursuant to which the formation and recapitalization transactions described above under Recapitalization were effected. The terms of the Contribution Agreement were determined by the Legacy Owners and, with respect to our interests thereunder, were not the result of arm s-length negotiations.

Registration Rights Agreement

In connection with the closing of our initial public offering, we entered into a shareholder and registration rights agreement, which we refer to as the registration rights agreement, with the Legacy Owners. Pursuant to the registration rights agreement, we have agreed to register the resale of all Class A shares issuable upon exercise of the Exchange Right (the Registrable Securities) held by the parties to the registration rights agreement under certain circumstances. Additionally, upon the vesting of the AAP Management Units, we have agreed to amend the registration rights agreement to include any Class A shares issuable upon exercise of the Exchange Right with respect to such vested AAP Management Units as Registrable Securities, so long as the holder of such units agrees to be bound by the terms and conditions of the registration rights agreement.

Lock-Up Agreement

For a period of 15 months following the closing of our initial public offering, the Legacy Owners affiliated with Oxy, EMG, Kayne Anderson and PAA Management have agreed not to sell, transfer, pledge or otherwise dispose of any Registrable Securities. This restriction will not apply to certain permitted transfers, including transfers that do not involve market sales, such as transfers to affiliates; however, any such permitted transfers, other than de minimis charitable gifts, will be made subject to the remaining term of the 15-month lock-up period. In addition, this 15-month lock-up may only be waived by the board of directors of our general partner (without participation of any representative of Oxy, EMG or Kayne Anderson) in its sole discretion.

Shelf Registration Statement

As soon as we are eligible to do so, we will be obligated to file and maintain a shelf registration statement on Form S-3 covering the resale of all of the Registrable Securities. We will be required to maintain the effectiveness of any such registration statement until the date on which all Registrable Securities covered by the shelf registration statement have been sold thereunder in accordance with the plan and method of distribution disclosed in the prospectus included in the shelf registration statement, or otherwise cease to be Registrable Securities under the registration rights agreement.

Demand and Piggyback Rights

Following the 15-month lock-up period, certain of the Legacy Owners will have the right to require that we register their Registrable Securities and/or facilitate an underwritten offering of their Registrable Securities. There is no aggregate limit on the number of such demand requests; however, the demand rights of these holders are subject to a number of size, frequency and other limitations.

In the event we propose to conduct an underwritten offering of Registrable Securities, then the holders of Registrable Securities will generally have customary rights to participate in such offering, subject to customary offering size limitations and related allocation provisions and other limitations. Similarly, in the event that eligible holders demand that we conduct an underwritten offering of their Registrable Securities, then we will generally have customary rights to participate in such offering, subject to customary offering size limitations and related allocation provisions and other limitations.

Delay Rights

We will not be required to comply with any demand request, and may suspend the holders ability to use any shelf registration statement, following our delivery of written notice to the holders of customary blackout periods and deferral events.

Expenses

The holders of Registrable Securities will pay certain selling expenses, including any underwriters discounts and commissions. We will generally cause AAP to pay all other registration expenses in connection with our obligations under the registration rights agreement.

Review, Approval or Ratification of Transactions with Related Persons

Pursuant to our Governance Guidelines, a director is expected to bring to the attention of the CEO or the board any conflict or potential conflict of interest that may arise between the director, his or her family members or any affiliate of the director, on the one hand, and the Partnership or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between the Partnership and our general partner, the resolution of any such conflict or potential conflict should be addressed by the board in accordance with the provisions of the Partnership Agreement. At the discretion of the board in light of the circumstances, the resolution

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may be determined by the board of directors of our general partner or by a conflicts committee meeting the definitional requirements for such a committee under the Partnership Agreement. Such resolution may include resolution of any derivative conflicts created by an executive officer s ownership of interests in our general partner of any of its affiliates or a director s appointment to the board of our general partner by an owner of interests in our general partner.

Pursuant to our Code of Business Conduct, any executive officer must avoid conflicts of interest unless approved by the board of directors of our general partner.

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Item 14. ***Principal Accountant Fees and Services***

The following table details the aggregate fees billed for professional services rendered by our independent auditor for services provided to us and to our consolidated subsidiaries (in millions):

	Year Ended December 31, 2013
Audit fees (1)	$ 5.2
Audit-related fees (2)	0.1
Tax fees (3)	1.5
All other fees (4)	0.2
Total	$ 7.0

(1) Audit fees include those related to (a) our annual audit; (b) the annual audits of PAA and PNG; (c) the audit of certain joint ventures of which we are the operator and (d) work performed on our and our subsidiaries registration of publicly held debt and equity.

(2) Audit-related fees are for an audit of our benefit plan.

(3) Tax fees are related to tax processing as well as the preparation of Forms K-1 for PAA and PNG s unitholders and international tax planning work associated with the structure of our Canadian investment.

(4) All other fees primarily consist of those associated with due diligence performed on our behalf and evaluating potential acquisitions.

Pre-Approval Policy

As discussed above, we have an audit committee that reviews our external financial reporting, engages our independent auditors and reviews the adequacy of our internal accounting controls. Our consolidated subsidiary, PAA, also has an audit committee that performs similar functions on PAA s behalf. Prior to the PNG Merger on December 31, 2013, our consolidated subsidiary, PNG, also had an audit committee that performed similar functions on PNG's behalf. All services provided by our independent auditor are subject to pre-approval by our audit committee or the audit committee of PAA or PNG (for services provided to PAA or PNG, respectively). However, prior to the completion of our initial public offering, our principal auditors were engaged to audit our financial statements, our predecessor financial statements and provide certain services associated with the filing of our Form S-1. These services totaled approximately $0.7 million (included in Audit fees in the table above) and were provided prior to our initial public offering and the formation of our audit committee and thus not subject to their pre-approval.

The audit committees have instituted policies that describe certain pre-approved non-audit services. We believe that the descriptions of services are designed to be sufficiently detailed as to particular services provided, such that (i) management is not required to exercise judgment as to whether a proposed service fits within the description and (ii) the audit committee knows what services it is being asked to pre-approve. The audit committees are informed of each engagement of the independent auditor to provide services under the respective policy. Except as noted above, all services provided by our independent auditor during the year ended December 31, 2013 were approved in advance by the applicable audit committee.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) **(1)** *Financial Statements*

See Index to the Consolidated Financial Statements set forth on Page F-1.

(2) *Financial Statement Schedules*

All schedules are omitted because they are either not applicable or the required information is shown in the consolidated financial statements or notes thereto.

(3) *Exhibits*

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

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SIGNATURES

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

	PLAINS GP HOLDINGS, L.P.	
	By:	PAA GP HOLDINGS LLC, *its general partner*
	By:	/s/ Greg L. Armstrong **Greg L. Armstrong,** ***Chairman of the Board, Chief Executive Officer and Director of PAA GP Holdings LLC (Principal Executive Officer)***
March 12, 2014		
	By:	/s/ Al Swanson **Al Swanson,** ***Executive Vice President and Chief Financial Officer of PAA GP Holdings LLC (Principal Financial Officer)***
March 12, 2014		
	By:	/s/ Chris Herbold **Chris Herbold,** ***Vice President-Accounting and Chief Accounting Officer of PAA GP Holdings LLC (Principal Accounting Officer)***
March 12, 2014		

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

Name	Title	Date
/s/ Greg L. Armstrong Greg L. Armstrong	Chairman of the Board, Chief Executive Officer and Director of PAA GP Holdings LLC (Principal Executive Officer)	March 12, 2014
/s/ Harry N. Pefanis Harry N. Pefanis	President and Chief Operating Officer of PAA GP Holdings LLC	March 12, 2014
/s/ Al Swanson Al Swanson	Executive Vice President and Chief Financial Officer of PAA GP Holdings LLC (Principal Financial Officer)	March 12, 2014
/s/ Chris Herbold Chris Herbold	Vice President Accounting and Chief Accounting Officer of PAA GP Holdings LLC (Principal Accounting Officer)	March 12, 2014
/s/ Victor Burk Victor Burk	Director of PAA GP Holdings LLC	March 12, 2014
/s/ Everardo Goyanes Everardo Goyanes	Director of PAA GP Holdings LLC	March 12, 2014
/s/ John T. Raymond John T. Raymond	Director of PAA GP Holdings LLC	March 12, 2014
/s/ Bobby S. Shackouls Bobby S. Shackouls	Director of PAA GP Holdings LLC	March 12, 2014
/s/ Robert V. Sinnott Robert V. Sinnott	Director of PAA GP Holdings LLC	March 12, 2014
/s/ Vicky Sutil Vicky Sutil	Director of PAA GP Holdings LLC	March 12, 2014

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Shareholders of

Plains GP Holdings, L.P.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income, of changes in accumulated other comprehensive income, of changes in partners capital/ members equity and of cash flows, present fairly, in all material respects, the financial position of Plains GP Holdings, L.P. and its subsidiaries (the Partnership) at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 12, 2014

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except shares)

	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 43	$ 25
Trade accounts receivable and other receivables, net	3,637	3,564
Inventory	1,065	1,209
Other current assets	220	351
Total current assets	4,965	5,149
PROPERTY AND EQUIPMENT	12,514	11,183
Accumulated depreciation	(1,673)	(1,519)
	10,841	9,664
OTHER ASSETS		
Goodwill	2,503	2,535
Linefill and base gas	798	707
Long-term inventory	251	274
Investments in unconsolidated entities	485	343
Other, net	1,610	587
Total assets	$ 21,453	$ 19,259
LIABILITIES AND PARTNERS CAPITAL / MEMBERS EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,985	$ 3,824
Short-term debt	1,113	1,086
Other current liabilities	315	275
Total current liabilities	5,413	5,185
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $15 and $15, respectively	6,710	6,010
Long-term debt under credit facilities and other	520	510
Other long-term liabilities and deferred credits	531	586
Total long-term liabilities	7,761	7,106
COMMITMENTS AND CONTINGENCIES (NOTE 16)		
PARTNERS CAPITAL / MEMBERS EQUITY		
Class A Shareholders (133,833,637 shares outstanding at December 31, 2013)	1,035	
Class B Shareholders (472,196,136 shares outstanding at December 31, 2013)		
Noncontrolling interests	7,244	6,968
Total partners capital / members equity	8,279	6,968
Total liabilities and partners capital / members equity	$ 21,453	$ 19,259

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Year Ended December 31, 2013	2012	2011
REVENUES			
Supply and Logistics segment revenues	$ 40,692	$ 36,438	$ 33,065
Transportation segment revenues	701	623	572
Facilities segment revenues	856	736	638
Total revenues	42,249	37,797	34,275
COSTS AND EXPENSES			
Purchases and related costs	38,465	34,368	31,564
Field operating costs	1,322	1,180	870
General and administrative expenses	360	342	294
Depreciation and amortization	378	483	250
Total costs and expenses	40,525	36,373	32,978
OPERATING INCOME	1,724	1,424	1,297
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	64	38	13
Interest expense (net of capitalized interest of $38, $36 and $25, respectively)	(309)	(295)	(259)
Other income/(expense), net	1	6	(19)
INCOME BEFORE TAX	1,480	1,173	1,032
Current income tax expense	(100)	(54)	(38)
Deferred income tax expense	(6)	(1)	(7)
NET INCOME	1,374	1,118	987
Net income attributable to noncontrolling interests	(1,359)	(1,115)	(985)
NET INCOME ATTRIBUTABLE TO PAGP	$ 15	$ 3	$ 2
BASIC AND DILUTED NET INCOME PER CLASS A SHARE (1)			
Basic and diluted weighted average Class A shares outstanding	132		
Basic and diluted net income per Class A share	$ 0.10		

(1) Basic and diluted net income per Class A share are calculated based on net income attributable to PAGP for the period following the closing of our initial public offering on October 21, 2013 and basic weighted average number of Class A shares outstanding weighted for the same period. See Note 4, Net Income Per Class A Share .

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Year Ended December 31, 2013	2012	2011
Net income	$ 1,374	$ 1,118	$ 987
Other comprehensive income/(loss)	(176)	29	(61)
Comprehensive income	1,198	1,147	926
Comprehensive income attributable to noncontrolling interests	(1,183)	(1,144)	(924)
Comprehensive income attributable to PAGP	$ 15	$ 3	$ 2

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

PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED

OTHER COMPREHENSIVE INCOME

(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
Balance at December 31, 2010	$ (86)	$ 198	$ (1)	$ 111
Reclassification adjustments	135			135
Deferred loss on cash flow hedges, net of tax	(155)			(155)
Currency translation adjustments		(42)		(42)
Proportionate share of our unconsolidated entities other comprehensive income			1	1
2011 Activity	(20)	(42)	1	(61)
Balance at December 31, 2011	$ (106)	$ 156	$	$ 50
Reclassification adjustments	(58)			(58)
Deferred gain on cash flow hedges, net of tax	43			43
Currency translation adjustments		44		44
2012 Activity	(15)	44		29
Balance at December 31, 2012	$ (121)	$ 200	$	$ 79
Reclassification adjustments	(66)			(66)
Deferred gain on cash flow hedges, net of tax	110			110
Currency translation adjustments		(220)		(220)
2013 Activity	44	(220)		(176)
Balance at December 31, 2013	$ (77)	$ (20)	$	$ (97)

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31, 2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,374	$ 1,118	$ 987
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	378	483	250
Inventory valuation adjustments	7	128	4
Equity-indexed compensation expense	116	101	110
Gain on sales of linefill and base gas	(7)	(19)	(21)
Settlement of terminated interest rate and foreign currency hedging instruments	8	(112)	12
Other	(1)	(1)	15
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	(185)	218	83
Inventory	134	(180)	518
Accounts payable and other current liabilities	124	(504)	399
Net cash provided by operating activities	1,948	1,232	2,357
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions, net of cash acquired (Note 3)	(28)	(2,156)	(1,390)
Change in restricted cash			20
Additions to property, equipment and other	(1,613)	(1,204)	(635)
Cash received for sales of linefill and base gas	40	65	56
Cash paid for purchases of linefill and base gas	(122)	(109)	(78)
Investment in unconsolidated entities	(133)	(76)	
Proceeds from sales of assets	200	22	12
Cash received upon formation of equity-method investment		59	
Other investing activities	3	7	(5)
Net cash used in investing activities	(1,653)	(3,392)	(2,020)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) under PAA senior secured hedged inventory facility (Note 9)	(660)	591	(425)
Net borrowings/(repayments) under PAA senior unsecured revolving credit facility (Note 9)	(92)	59	(793)
Net borrowings/(repayments) under PNG credit agreement (Note 9)	(382)	61	62
Net borrowings/(repayments) under AAP revolving credit facility (Note 9)	15	(7)	3
Proceeds from AAP term loan (Note 9)	300		
Net borrowings under PAA commercial paper program (Note 9)	1,110		
Proceeds from the issuance of PAA senior notes	699	1,996	597
Repayments of PAA senior notes	(250)	(500)	(200)
Net proceeds from the issuance of PAA common units	465	959	870
Contributions from noncontrolling interests related to PAA common unit issuances	10	28	17
Net proceeds from the issuance of PNG common units	40		370

Proceeds received from initial public offering (Note 10)	2,825		
Distribution of proceeds received from initial public offering (Note 10)	(2,825)		
Distributions paid to noncontrolling interests (Note 10)	(1,494)	(1,005)	(822)
Distributions paid to members (Note 10)	(6)	(3)	(2)
Other financing activities	(29)	(20)	(14)
Net cash provided by/(used in) financing activities	(274)	2,159	(337)
Effect of translation adjustment on cash	(3)	(1)	(10)
Net increase/(decrease) in cash and cash equivalents	18	(2)	(10)
Cash and cash equivalents, beginning of period	25	27	37
Cash and cash equivalents, end of period	$ 43	$ 25	$ 27
Cash paid for:			
Interest, net of amounts capitalized	$ 312	$ 302	$ 261
Income taxes, net of amounts refunded	$ 37	$ 72	$ 11

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS CAPITAL / MEMBERS EQUITY

(in millions)

	Members Equity (Excluding Noncontrolling Interests)	Partners Capital (Excluding Noncontrolling Interests) Class A Shares	Class B Shares	Noncontrolling Interests	Total Partners Capital/ Members Equity
Balance at December 31, 2010	$	$	$	$ 4,391	$ 4,391
Net income	2			985	987
Distributions	(2)			(822)	(824)
Issuance of PAA common units				870	870
Issuance of PAA common units under LTIP				15	15
Contributions from noncontrolling interests related to PAA common unit issuances				19	19
Issuance of PNG common units				370	370
Equity-indexed compensation expense				28	28
Other comprehensive loss				(61)	(61)
Other				(1)	(1)
Balance at December 31, 2011	$	$	$	$ 5,794	$ 5,794
Net income	3			1,115	1,118
Distributions	(3)			(1,005)	(1,008)
Issuance of PAA common units				959	959
Issuance of PAA common units under LTIP				33	33
Contributions from noncontrolling interests related to PAA common unit issuances				21	21
Equity-indexed compensation expense				28	28
Distribution equivalent right payments				(5)	(5)
Other comprehensive income				29	29
Other				(1)	(1)
Balance at December 31, 2012	$	$	$	$ 6,968	$ 6,968
Net income	3	12		1,359	1,374
Distributions	(6)			(1,494)	(1,500)
Transfer of ownership interest	3	(52)		49	
Issuance of Class A shares to the public, net of offering and other costs		2,825			2,825
Distribution of net proceeds of initial public offering		(2,825)			(2,825)
Deferred tax asset		1,076			1,076
Issuance of PAA common units				468	468
Issuance of PAA common units under LTIP				4	4
Contributions from noncontrolling interests related to PAA common				9	9

unit issuances					
Units tendered by employees to satisfy tax withholding obligations				(15)	(15)
Issuance of PNG common units				40	40
Equity-indexed compensation expense				39	39
Distribution equivalent right payments				(6)	(6)
Other comprehensive loss				(176)	(176)
Other		(1)		(1)	(2)
Balance at December 31, 2013	$	$ 1,035	$	$ 7,244	$ 8,279

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Basis of Presentation

Organization

Plains GP Holdings, L.P. (PAGP) is a Delaware limited partnership formed on July 17, 2013 to own an interest in the general partner and incentive distribution rights (IDRs) of Plains All American Pipeline, L.P (PAA), a publicly traded Delaware limited partnership. PAGP has elected to be treated as a corporation for U.S. federal income tax purposes.

We completed our initial public offering (IPO) on October 21, 2013. Immediately prior to our IPO, certain owners of Plains AAP, L.P. (AAP) sold a portion of their interests in AAP to us, resulting in our ownership of AAP units, which represent limited partnership interests in AAP. As of December 31, 2013, we owned 133,833,637 AAP units (representing a 22.1% limited partner interest in AAP), and the remaining AAP units continue to be held by the owners of AAP immediately prior to our IPO (the Legacy Owners). AAP is a Delaware limited partnership that directly owns all of PAA s incentive distribution rights and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP LLC (PAA GP), a Delaware limited liability company that directly holds the 2% general partner interest in PAA. Also, through a series of transactions prior to our IPO with our general partner and the owners of Plains All American GP LLC (GP LLC), a Delaware limited liability company formed on May 2, 2001, GP LLC s general partner interest in AAP became a non-economic interest, and we became the owner of a 100% managing member interest in GP LLC. See Basis of Consolidation and Presentation below for the resulting accounting impacts.

GP LLC manages the business and affairs of PAA and AAP. Except for certain matters relating to PAA that require the approval of the limited partners of PAA, and certain matters relating to AAP that require the approval of the limited partners of AAP or of us as the sole member of GP LLC, either pursuant to the governing documents of PAA, AAP or GP LLC, or as may be required by non-waivable provisions of applicable law, GP LLC has full and complete authority, power and discretion to manage and control the business, affairs and property of PAA and AAP, to make all decisions regarding those matters and to perform any and all other acts or activities customary or incident to the management of PAA and AAP s business, including the execution of contracts and management of litigation. GP LLC employs all domestic officers and personnel involved in the operation and management of PAA and AAP. PAA s Canadian officers and personnel are employed by Plains Midstream Canada ULC.

PAA is a publicly traded master limited partnership that owns and operates midstream energy infrastructure and provides logistics services for crude oil, natural gas liquids (NGL), natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas (LPG) such as propane and butane. When used in this Form 10-K, NGL refers to all NGL products including LPG. PAA owns an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 18 for further discussion of our operating segments.

As used in this Form 10-K and unless the context indicates otherwise, the terms PAGP, Partnership, Plains, we, us, our, ours and simil refer to PAGP, GP LLC, AAP, PAA GP and PAA and its consolidated subsidiaries.

Definitions

Additional defined terms are used in the following notes and shall have the meanings indicated below:

AOCI	=	Accumulated other comprehensive income
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
CERCLA	=	Federal Comprehensive Environmental Response, Compensation and Liability Act, as amended
CME	=	Chicago Mercantile Exchange
DERs	=	Distribution equivalent rights
EBITDA	=	Earnings before interest, taxes, depreciation and amortization
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	Intercontinental Exchange

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IPO	=	Initial public offering
LIBOR	=	London Interbank Offered Rate
LLS	=	Light Louisiana Sweet
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
MQD	=	Minimum quarterly distribution
NGL	=	Natural gas liquids including ethane, natural gasoline products, propane and butane
NYMEX	=	New York Mercantile Exchange
NYSE	=	New York Stock Exchange
Pacific	=	Pacific Energy Partners, L.P.
PLA	=	Pipeline loss allowance
PNG	=	PAA Natural Gas Storage, L.P.
PNGS	=	PAA Natural Gas Storage, LLC
Rainbow	=	Rainbow Pipe Line Company, Ltd.
RCRA	=	Federal Resource Conservation and Recovery Act, as amended
SG Resources	=	SG Resources Mississippi, LLC
SLC Pipeline	=	SLC Pipeline LLC
SOP	=	Shell Oil Products
USD	=	United States dollar
Velocity	=	Velocity South Texas Gathering, LLC
White Cliffs	=	White Cliffs Pipeline, LLC
WTI	=	West Texas Intermediate
WTS	=	West Texas Sour

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present and discuss our consolidated financial position as of December 31, 2013 and 2012, and the consolidated results of our operations, cash flows, changes in partners capital, comprehensive income and changes in accumulated other comprehensive income for the years ended December 31, 2013, 2012 and 2011. These financials include PAGP and all of our wholly owned subsidiaries and those entities that we control. Under GAAP, we consolidate PAA, AAP and GP LLC. Amounts associated with the interests in these entities not owned by us are reflected in our results of operations as net income attributable to noncontrolling interests and in our balance sheet partners capital section as noncontrolling interests.

For periods prior to our IPO, the accompanying consolidated financial statements reflect the financial statements of GP LLC, the predecessor of PAGP, and are based on the historical ownership percentages of GP LLC and AAP. These financial statements, to the extent they relate to periods prior to our IPO, have been prepared from the separate financial records maintained by GP LLC and may not necessarily be indicative of the actual results of operations that might have occurred if PAGP had operated separately during those periods.

All significant intercompany transactions have been eliminated in consolidation. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We evaluate our equity investments for impairment in accordance with FASB guidance with respect to the equity method of accounting for investments in common stock. An impairment of an equity investment results when factors indicate that the investment s fair value is less than its carrying value and the reduction in value is other than temporary in nature.

Subsequent events have been evaluated through the financial statements issuance date and have been included in the following footnotes where applicable.

Completion of PNG Merger

On October 21, 2013, PAA entered into a definitive agreement and plan of merger (the PNG Merger Agreement) with PNG that provided for a merger whereby PNG would become PAA s wholly-owned subsidiary through a unit-for-unit exchange. On December 31, 2013, PNG s common unitholders approved the PNG Merger Agreement, with PNG surviving the transactions as PAA s wholly-owned subsidiary (referred to herein as the PNG Merger). Since we historically consolidated PNG for financial reporting purposes, the PNG Merger did not change the basis of consolidation of our historical financial statements.

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Note 2 Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We make significant estimates with respect to (i) purchases and sales accruals, (ii) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) mark-to-market gains and losses on derivative instruments (pursuant to guidance issued by the FASB regarding fair value measurements), (iv) accruals and contingent liabilities, (v) equity-indexed compensation plan accruals, (vi) property and equipment and depreciation expense and (vii) allowance for doubtful accounts. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Supply and Logistics Segment Revenues. Revenues from sales of crude oil and NGL are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Sales of crude oil and NGL consist of outright sales contracts. Inventory purchases and sales under buy/sell transactions are treated as inventory exchanges. The sales under these exchanges are netted to zero in Supply and Logistics segment revenues in our Consolidated Statements of Operations.

Additionally, we may utilize derivatives in connection with the transactions described above. For commodity derivatives that are designated as cash flow hedges, derivative gains and losses are deferred in AOCI and recognized in revenues in the periods during which the underlying physical hedged transaction impacts earnings. Also, the ineffective portion of the change in fair value of cash flow hedges is recognized in revenues each period along with the change in fair value of derivatives that do not qualify for or are not designated for hedge accounting.

Transportation Segment Revenues. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and NGL at a published tariff, as well as revenues associated with leases and other agreements for committed space on various assets. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with lease fees are recognized in the month to which the lease applies. The majority of our pipeline tariff and fee revenues are based on actual volumes and rates. As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. In addition, we have certain agreements that require counterparties to ship a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume is shipped (pursuant to specifications outlined in the tariffs) or when the counterparty s ability to make up the minimum volume has expired.

Facilities Segment Revenues. Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, NGL and natural gas, NGL fractionation and isomerization services and natural gas and condensate processing services. Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and redeliver the applicable product to another connecting carrier, (iii) rail terminal loading and unloading fees, (iv) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (v) revenues from the sale of natural gas, (vi) fees from NGL fractionation and isomerization and (vii) fees from gas processing services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Storage fees resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. Terminal fees (including throughput and rail fees) are recognized as the crude oil, NGL or refined product enters or exits the terminal and is received from or delivered to the connecting carrier or third-party terminal, as applicable. Hub service fees are recognized in the period the natural gas moves across our header system. Fees from NGL fractionation, isomerization services and gas processing services are recognized in the period when the services are performed. Revenues associated with the sale of natural gas are recognized at the time title to the product sold transfers to the purchaser or its designee. In addition, we have certain agreements that require counterparties to throughput a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume exits the terminal or when the counterparty s ability to make up the minimum volume has expired.

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Purchases and Related Costs

Purchases and related costs include (i) the cost of crude oil, NGL, natural gas and refined products obtained in outright purchases, (ii) fees incurred for third-party transportation and storage, whether by pipeline, truck, rail, ship or barge, (iii) interest cost attributable to borrowings for inventory stored in a contango market and (iv) performance-related bonus costs. These costs are recognized when incurred except in the case of products purchased, which are recognized at the time title transfers to us. Purchases that are part of exchanges under buy/sell transactions are netted with the related sales, with any margin presented in Purchases and related costs in our Consolidated Statements of Operations.

Field Operating Costs and General and Administrative Expenses

Field operating costs consist of various field operating expenses, including fuel and power costs, telecommunications, payroll and benefit costs (including equity-indexed compensation expense) for truck drivers and field personnel, third-party trucking transportation costs for our U.S. crude oil operations, maintenance and integrity management costs, regulatory compliance, environmental remediation, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs (including equity-indexed compensation expense), certain information systems and legal costs, office rent, contract and consultant costs and audit and tax fees.

Foreign Currency Transactions

Certain of our subsidiaries use the Canadian dollar as their functional currency. Assets and liabilities of subsidiaries with a Canadian dollar functional currency are translated at period-end rates of exchange, and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income, which is reflected in Partners Capital on our Consolidated Balance Sheet.

Certain of our subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than the entities respective functional currencies. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in the Consolidated Statements of Operations. The revaluation of foreign currency transactions and monetary assets and liabilities resulted in a gain of approximately $1 million for the year ended December 31, 2013 and losses of approximately $2 million for each of the years ended December 31, 2012 and 2011.

Cash and Cash Equivalents

Cash and cash equivalents consist of all unrestricted demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal. In accordance with our policy, outstanding checks are classified as accounts payable rather than negative cash. As of December 31, 2013 and 2012, accounts payable included approximately $70 million and $72 million, respectively, of outstanding checks that were reclassified from cash and cash equivalents.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL and natural gas storage. These purchasers include, but are not limited to refiners, producers, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The majority of our accounts receivable relate to our crude oil supply and logistics activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

To mitigate credit risk related to our accounts receivable, we have in place a rigorous credit review process. We closely monitor market conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, parental guarantees or advance cash payments. At December 31, 2013 and 2012, we had received approximately $117 million and $173 million, respectively, of advance cash payments from third parties to mitigate credit risk. Furthermore, at December 31, 2013 and 2012, we had received approximately $426 million and $343 million, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. In addition, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Further, we enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet) for a majority of such arrangements.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At December 31, 2013 and 2012, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled approximately $5 million and $4 million at December 31, 2013 and 2012, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

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Equity Method of Accounting

Our investments in the following entities are accounted for under the equity method of accounting:

Entity	**Type of Operation**	**Our Ownership Interest**
Settoon Towing, LLC	Barge Transportation Services	50%
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%
Frontier Pipeline Company	Crude Oil Pipeline	22%
Butte Pipe Line Company	Crude Oil Pipeline	22%

We do not consolidate any part of the assets or liabilities of our equity investees. Our share of net income or loss is reflected as one line item on our Consolidated Statements of Operations entitled Equity earnings in unconsolidated entities and will increase or decrease, as applicable, the carrying value of our investments in unconsolidated entities on the balance sheet. In addition, as applicable, we include a proportionate share of our equity method investees unrealized gains and losses in other comprehensive income on our Consolidated Balance Sheet. We also adjust our investment balances in these investees by the like amount. Distributions we receive reduce the carrying value of our investments and will be reflected in our Consolidated Statements of Cash Flows in operating activities. In turn, contributions will increase the carrying value of our investments and will be reflected in our Consolidated Statements of Cash Flows in investing activities.

During the year ended December 31, 2013, we contributed approximately $133 million to our equity method investees. Such contributions were primarily to Eagle Ford Pipeline LLC and White Cliffs Pipeline LLC for construction and expansion activities.

In August 2012, we formed Eagle Ford Pipeline LLC with Enterprise Products Partners (Enterprise) for the purpose of developing a crude oil pipeline system in the Eagle Ford Area of South Texas. In conjunction with the formation, we and Enterprise contributed fixed assets with estimated book values of approximately $134 million and $15 million, respectively. In addition, Enterprise contributed cash of $59 million, which we received from Eagle Ford Pipeline LLC. Subsequent to the formation and through December 31, 2012, we and Enterprise contributed $75 million each to fund continued development of the pipeline system.

We received distributions of approximately $55 million, $40 million and $23 million from our equity method investees during the years ended December 31, 2013, 2012 and 2011, respectively.

Noncontrolling Interests

We account for noncontrolling interests in subsidiaries in accordance with FASB guidance, which requires all entities to report noncontrolling interests in subsidiaries as a component of equity in the consolidated financial statements. Noncontrolling interest represents the portion of assets and liabilities in a consolidated subsidiary that is owned by a third-party. See Note 10 for additional discussion regarding our noncontrolling interests.

Asset Retirement Obligations

FASB guidance establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including estimates related to (i) the time of the liability recognition, (ii) initial measurement of the liability, (iii) allocation of asset retirement cost to expense, (iv) subsequent measurement of the liability and (v) financial statement disclosures. FASB guidance also requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Some of our assets, primarily related to our Transportation and Facilities segments, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. These obligations include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets and returning the land to its original state. These assets have been in existence for many years and with regular maintenance will continue to be in service for many years to come. It is not possible to predict when demand for these transportation or storage services will cease, and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligations. We will record asset retirement obligations for these assets in the period in which sufficient information becomes available for us to reasonably determine the settlement dates.

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A small portion of our contractual or regulatory obligations is related to assets that are inactive or that we plan to take out of service and, although the ultimate timing and costs to settle these obligations are not known with certainty, we have recorded a reasonable estimate of these obligations. We have estimated that the fair value of these obligations was approximately $34 million and $31 million, respectively, at December 31, 2013 and 2012.

Fair Value Measurements

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which affects the placement of assets and liabilities within the fair value hierarchy levels. The determination of the fair values includes not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives, interest rate derivatives and foreign currency derivatives includes adjustments for credit risk. Our credit adjustment methodology uses market observable inputs and requires judgment. There were no changes to any of our valuation techniques during the period. See Notes 9 and 11 for further discussion.

Other Significant Accounting Policies

See the respective footnotes for our accounting policies regarding (i) net income per Class A share, (ii) inventory, linefill and base gas and long-term inventory, (iii) property and equipment, (iv) other assets, (v) goodwill, (vi) derivatives and risk management activities, (vii) income taxes, (viii) equity-indexed compensation and (ix) environmental matters.

Recent Accounting Pronouncements

In March 2013, the FASB issued guidance regarding the release of cumulative translation adjustments into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity. This guidance becomes effective beginning after December 15, 2013. We adopted this guidance on January 1, 2014. Our adoption is not expected to have a material impact on our financial position, results of operations or cash flows.

In February 2013, the FASB issued guidance requiring an entity to present either in a single note or parenthetically on the face of the financial statements (i) the amount of significant items reclassified from each component of AOCI and (ii) the income statement line items affected by the reclassification. This guidance became effective for interim and annual periods beginning after December 15, 2012. We adopted this guidance during the first quarter of 2013. For the years ended December 31, 2013, 2012 and 2011, all reclassifications out of AOCI were related to derivative instruments. Other than requiring additional disclosure, which is included in Note 11, our adoption did not have an impact on our financial position, results of operations or cash flows.

In July 2012, the FASB issued guidance intended to simplify the impairment test for indefinite-lived intangible assets other than goodwill by giving entities the option to first assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. The results of the qualitative assessment would be used as a basis in determining whether it is necessary to perform the two-step quantitative impairment testing. An entity can choose to perform the qualitative assessment on none, some or all of its indefinite-lived intangible assets, or may bypass the qualitative assessment and proceed directly to the quantitative impairment test. This guidance is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted in certain circumstances. We adopted this guidance on January 1, 2013. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In December 2011, the FASB issued guidance requiring disclosures of both gross and net information about recognized financial instruments and derivative instruments that are either (i) offset in accordance with the specified sections of GAAP or

(ii) subject to an enforceable master netting arrangement or similar agreement. In January 2013, the FASB amended and clarified the scope of these disclosures to include only (i) derivative instruments, (ii) repurchase agreements and reverse repurchase agreements and

(iii) securities lending transactions. This guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. We adopted this guidance on January 1, 2013. Other than requiring additional disclosure,

which is included in Note 11, our adoption did not have an impact on our financial position, results of operations or cash flows.

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Note 3 Acquisitions and Dispositions

The following acquisitions were accounted for using the acquisition method of accounting and the determination of the fair value of the assets and liabilities acquired has been estimated in accordance with the applicable accounting guidance.

2013 Acquisitions

During the year ended December 31, 2013, we completed an acquisition for aggregate consideration of approximately $19 million. The assets acquired included a trucking business included in our Transportation segment. We recognized goodwill of approximately $6 million related to this acquisition.

2012 Acquisitions

BP NGL Acquisition

On April 1, 2012, we acquired all of the outstanding shares of BP Canada Energy Company (BPCEC), a wholly owned subsidiary of BP Corporation North America Inc. (BP North America) from Amoco Canada International Holdings B.V. (the Seller). Total consideration for this acquisition (referred to herein as the BP NGL Acquisition), which was based on an October 1, 2011 effective date, was approximately $1.68 billion in cash, including $17 million of imputed interest, subject to working capital and other adjustments.

The determination of the fair value of the assets and liabilities acquired is as follows (in millions):

Description		Amount	Average Depreciable Life (in years)
Working capital	$	241	N/A
Property and equipment		1,081	5 - 70
Linefill		85	N/A
Long-term inventory		165	N/A
Intangible assets (contract)		130	13
Goodwill		236	N/A
Deferred tax liability		(236)	N/A
Environmental liability		(14)	N/A
Other long-term liabilities		(5)	N/A
Total	$	1,683	

The purchase price was equal to the fair value of the net tangible and intangible assets acquired, excluding the resulting deferred tax liability and goodwill. The deferred tax liability is determined by the difference between the fair value of the acquired assets and liabilities and the tax basis for those assets and liabilities. The resulting liability gives rise to an equal and offsetting goodwill balance for this transaction.

Intangible assets above consisted of a contract with a 13 year life. Amortization of this contract under the declining balance method was approximately $31 million and $41 million during the years ended December 31, 2013 and 2012, respectively, and the future amortization through 2017 is estimated as follows:

2014	$	10
2015	$	8
2016	$	7
2017	$	6

The BP NGL Acquisition was pre-funded through various means, including the issuance of PAA common units and senior notes in March 2012 for net proceeds of approximately $1.69 billion. During the year ended December 31, 2012, we incurred approximately $13 million of acquisition-related costs associated with the BP NGL Acquisition. Such costs are reflected as a component of General and administrative expenses in our Consolidated Statement of Operations.

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USD Rail Terminal Acquisition

On December 12, 2012, we completed a transaction with U.S. Development Group (referred to herein as the USD Rail Terminal Acquisition) for an aggregate consideration of approximately $503 million, paid in cash. Through the USD Rail Terminal Acquisition, we acquired four operating crude oil rail terminals and one terminal under development. The determination of the fair value of the assets and liabilities acquired was approximately $1 million of working capital, $76 million of property and equipment and $426 million of goodwill. The goodwill arising from the USD Rail Terminal Acquisition represents anticipated opportunities to generate future cash flows from the rail facilities by utilizing them to reduce capacity constraints in certain geographic market areas.

Other 2012 Acquisitions

During the year ended December 31, 2012, we completed several additional acquisitions for an aggregate consideration of approximately $150 million. The assets acquired primarily included crude oil and condensate gathering pipelines, a truck unloading terminal and trailers that are utilized in our Transportation segment, and terminal facilities included in our Facilities segment. We recognized goodwill of approximately $10 million related to these acquisitions.

Pro Forma Results

Disclosure of the revenues and earnings from the BP NGL Acquisition, USD Rail Terminal Acquisition and our other 2012 acquisitions in our results for the year ended December 31, 2012 is not practicable as they are not being operated as standalone subsidiaries. Selected unaudited pro forma results of operations for the years ended December 31, 2012 and 2011, assuming our 2012 acquisitions had occurred on January 1, 2011, are presented below (in millions):

	Year Ended December 31,			
	2012		2011	
Total revenues	$	38,729	$	37,493
Net income attributable to PAGP	$	3	$	2

2011 Acquisitions

Southern Pines Acquisition

On February 9, 2011, we acquired 100% of the equity interests in SG Resources from SGR Holdings, L.L.C. (the Southern Pines Acquisition) for an aggregate purchase price of approximately $765 million in cash (approximately $750 million, net of cash and other working capital acquired). The purchase price included the release of restricted cash of approximately $20 million held in escrow prior to the closing of the acquisition. The primary asset of SG Resources is the Southern Pines Energy Center (Southern Pines), a FERC-regulated, salt-cavern natural gas storage facility located in Greene County, Mississippi.

The fair value of assets acquired and liabilities assumed was as follows (in millions):

Description		**Amount**	**Average Depreciable Life (in years)**
Inventory	$	14	N/A
Property and equipment		340	5 - 70
Base gas		3	N/A
Other working capital (including approximately $13 million of cash acquired)		15	N/A
Intangible assets		92	2 - 10
Goodwill		301	N/A
Total	$	765	

The allocation of fair value to intangible assets above was comprised of a tax abatement valued at approximately $15 million and contracts valued at approximately $77 million. Goodwill or indefinite lived intangible assets will not be subject to depreciation or amortization, but will be subject to periodic impairment testing and, if necessary, will be written down to fair value should circumstances warrant.

Several factors contributed to a purchase price in excess of the fair value of the net tangible and intangible assets acquired. Such factors included the strategic location of the Southern Pines facility, the limited alternative locations and the extended lead times required to develop and construct such facility, along with its operational flexibility, organic expansion capabilities and synergies anticipated to be obtained from combining Southern Pines with our existing asset base. This acquisition is reflected in our Facilities segment.

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Other 2011 Acquisitions

Western Acquisition. On December 29, 2011, we completed two transactions with Western Refining for a combined consideration of approximately $220 million in cash. Through the first transaction, we acquired crude oil, refined products and NGL storage and the associated manifold and pumping equipment located at Western s Yorktown, Virginia refinery site, which we operate as a terminal, as well as certain intangible assets. The second transaction included an 82-mile, 16-inch segment of pipeline that originates in Chaves County, New Mexico and connects into our Basin Pipeline system at Jal, New Mexico. The transaction includes associated tankage, piping and other related assets at the Lynch and Jal Stations.

Gardendale Gathering System Acquisition. On November 29, 2011, we completed the acquisition of 100% of the member interests in Velocity from Velocity Midstream Partners, LLC for an aggregate consideration of approximately $349 million in cash. The assets acquired included approximately 120 miles of crude oil and condensate gathering and transportation pipelines (the Gardendale Gathering System) in the Eagle Ford Shale. We recognized goodwill of approximately $155 million associated with this acquisition, which was primarily related to the potential incremental income from anticipated growth projects.

Additional 2011 Acquisitions. During 2011, we completed six additional acquisitions for an aggregate consideration of approximately $20 million. These acquisitions included propane storage and terminal facilities included in our Facilities segment, a trucking business included in our Transportation segment as well as the right to ship on third-party pipelines, the revenues of which are included in our Supply and Logistics segment.

The determination of fair value of assets acquired and liabilities assumed for all other acquisitions completed during 2011, including the Western and Gardendale Gathering System acquisitions, is as follows (in millions):

Description		**Amount**
Inventory	$	2
Linefill		2
Property and equipment		280
Other working capital, net of cash acquired		(6)
Intangible assets		142
Environmental liability		(9)
Goodwill		178
Total	$	589

Dispositions

During 2013, 2012 and 2011, we sold various property and equipment for proceeds totaling approximately $200 million, $22 million and $12 million, respectively. Gains of less than $1 million and approximately $6 million and a loss of approximately $6 million were recognized in 2013, 2012 and 2011, respectively, related to these sales.

In February 2013, we signed a definitive agreement to sell certain refined products pipeline systems and related assets included in our Transportation segment. At December 31, 2012, these assets were classified as held for sale on our Consolidated Balance Sheet (in Other current assets). We closed a portion of the transaction on July 1, 2013 and the balance in November 2013.

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Note 4 Net Income Per Class A Share

Basic net income per Class A share is determined by dividing net income attributable to PAGP by the weighted average number of outstanding Class A shares during the period. Class B shares do not share in the earnings of the Partnership. Accordingly, basic and diluted net income per Class B share has not been presented. Diluted net income per Class A share is determined by dividing net income attributable to PAGP by the weighted average number of outstanding diluted Class A shares during the period. For the purposes of the calculation of diluted net income per Class A share, both the net income attributable to PAGP and the weighted average number of outstanding diluted Class A shares consider the impact of possible future exchange of (i) certain AAP units and the associated Class B shares into our Class A shares and (ii) certain AAP Management Units into our Class A shares. See Note 10 for discussion of possible conversion of such shares.

AAP Management Units are considered potentially dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. See Note 15 for a discussion of the vesting terms of the AAP Management Units. Conversions of AAP units and AAP Management Units are assumed to have occurred at the beginning of the period (the date of the closing of our IPO in this instance) and the incremental income attributable to PAGP resulting from the assumed conversions is representative of the incremental income that would have been attributable to PAGP if the assumed conversions occurred on that date.

For the period from October 21, 2013 (the closing of our IPO) through December 31, 2013, the possible conversion of certain AAP units and AAP Management Units would both be anti-dilutive. As there are no dilutive units for the period, the following table illustrates the calculation of both basic net income per Class A share and diluted net income per Class A share (amounts in millions, except per share data):

		October 21, 2013 to December 31, 2013
Basic and Diluted Net Income per Class A Share		
Net income attributable to PAGP	$	15
Less net income attributable to PAGP for the period from January 1, 2013 to October 20, 2013		(3)
Net income attributable to PAGP for the period from October 21, 2013 to December 31, 2013	$	12
Basic and diluted weighted average number of Class A shares outstanding (1)		132
Basic and diluted net income per Class A share	$	0.10

(1) Basic weighted average number of Class A shares outstanding is weighted for the period following the closing of our IPO. Approximately 128 million Class A shares were issued upon closing of our IPO with approximately 4 million additional Class A shares issued through the exercise in October 2103 of an over-allotment option. Subsequent conversions of AAP units were immaterial.

Note 5 Inventory, Linefill and Base Gas and Long-term Inventory

Inventory primarily consists of crude oil, NGL and natural gas in pipelines, storage facilities and railcars that are valued at the lower of cost or market, with cost determined using an average cost method within specific inventory pools. At the end of each reporting period, we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. We recorded non-cash charges of approximately $7 million and $128 million for the years ended December 31, 2013 and 2012, respectively related to the writedown of our crude oil and NGL inventory due to declines in prices during the period. As of December 31, 2013 and 2012, a majority of the inventory subject to writedown in each period had been liquidated and the applicable derivative instruments had been settled by the end of each year. The recognition of these adjustments in 2013 and 2012, which are a component of Purchases and related costs in our accompanying Consolidated Statement of Operations, was substantially offset by the recognition of gains on derivative instruments being utilized to hedge the future sales of our crude oil and NGL inventory. Substantially all of such gains were recorded to Supply and Logistics segment revenues in our Consolidated Statement of Operations. See Note 11 for discussion of our derivative and risk management activities. We did not recognize a material writedown of inventory during 2011.

Linefill and base gas and minimum working inventory requirements in assets we own are recorded at historical cost and consist of crude oil, NGL and natural gas. We classify as linefill or base gas (i) our proportionate share of barrels used to fill a pipeline that we own such that when an incremental barrel is pumped into or enters a pipeline it forces product out at another location, (ii) barrels that represent the minimum working requirements in tanks that we own and (iii) natural gas required to maintain the minimum operating pressure of natural gas storage facilities we own. During 2013, 2012 and 2011, we recorded gains of approximately $7 million, $19 million and $21 million, respectively, on the sale of linefill and base gas for proceeds of approximately $40 million, $65 million and $56 million, respectively.

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Minimum working inventory requirements in third-party assets and other working inventory in our assets that is needed for our commercial operations are included within specific inventory pools in inventory (a current asset) in determining the average cost of operating inventory. At the end of each period, we reclassify the inventory not expected to be liquidated within the succeeding twelve months out of inventory, at the average cost of the applicable inventory pools, and into long-term inventory, which is reflected as a separate line item in Other assets on our Consolidated Balance Sheet.

Inventory, linefill and base gas and long-term inventory consisted of the following as of the dates indicated (barrels and natural gas volumes in thousands and carrying value in millions):

	December 31, 2013				December 31, 2012			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)
Inventory								
Crude oil	6,951	barrels	$ 540	$ 77.69	9,492	barrels	$ 737	$ 77.64
NGL	8,061	barrels	352	$ 43.67	9,472	barrels	388	$ 40.96
Natural gas	40,505	Mcf	150	$ 3.70	20,374	Mcf	60	$ 2.94
Other	N/A		23	N/A	N/A		24	N/A
Inventory subtotal			1,065				1,209	
Linefill and base gas								
Crude oil	10,966	barrels	679	$ 61.92	9,919	barrels	583	$ 58.78
NGL	1,341	barrels	62	$ 46.23	1,400	barrels	70	$ 50.00
Natural gas	16,615	Mcf	57	$ 3.43	15,755	Mcf	54	$ 3.43
Linefill and base gas subtotal			798				707	
Long-term inventory								
Crude oil	2,498	barrels	202	$ 80.86	1,962	barrels	149	$ 75.94
NGL	1,161	barrels	49	$ 42.20	3,238	barrels	125	$ 38.60
Long-term inventory subtotal			251				274	
Total			$ 2,114				$ 2,190	

(1) Price per unit of measure represents a weighted average associated with various grades, qualities and locations. Accordingly, these prices may not coincide with any published benchmarks for such products.

Note 6 Property and Equipment

In accordance with our capitalization policy, expenditures made to expand the existing operating and/or earnings capacity of our assets, including related interest costs, are capitalized. For the years ended December 31, 2013, 2012 and 2011, capitalized interest was $38 million, $36 million and $25 million, respectively. We also capitalize expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are expensed as incurred.

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

	Estimated Useful Lives (Years)	December 31, 2013	2012
Pipelines and related facilities	10 - 70	$ 6,154	$ 5,346
Storage, terminal and rail facilities	30 - 70	4,704	4,354
Trucking equipment and other	3 - 15	150	136
Construction in progress		1,008	910
Office property and equipment	2 - 50	125	111
Land and other	N/A	373	326
		12,514	11,183
Accumulated depreciation		(1,673)	(1,519)
Property and equipment, net		$ 10,841	$ 9,664

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Depreciation expense for the years ended December 31, 2013, 2012 and 2011 was approximately $262 million, $223 million and $197 million, respectively. We also classify gains and losses on sales of assets and asset impairments as a component of Depreciation and amortization in our Consolidated Statements of Operations. See Note 3 for additional information regarding dispositions. See Impairment of Long-Lived Assets below for a discussion of our policy for the recognition of asset impairments.

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. During 2011, we extended the depreciable lives of several of our crude oil and other storage facilities and pipeline systems based on a review to assess the useful lives of our property and equipment and to adjust those lives, if appropriate, to reflect current expectations given actual experience and current technology. For the year ended December 31, 2012, these extensions reduced depreciation expense by $13 million as compared to the year ended December 31, 2011.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value in accordance with FASB guidance with respect to the accounting for the impairment or disposal of long-lived assets. Under this guidance, a long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized.

We periodically evaluate property and equipment and other long-lived assets 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. The subjective assumptions used to determine the existence of an impairment in carrying value include:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of holding, abandoning or 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.

For the years ended December 31, 2013 and 2011, we recognized impairments of approximately $20 million and $5 million, respectively, related predominantly to assets taken out of service.

During the year ended December 31, 2012, we recognized losses on impairments of long-lived assets of approximately $168 million, primarily related to our Pier 400 terminal project, which is reflected in Depreciation and amortization on our Consolidated Statement of Operations. This project, which we acquired in late 2006 by virtue of our merger with Pacific, was to develop 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 feedstock. During the third quarter of 2012, we decided not to proceed with the development of this project. A number of factors contributed to the uncertainties with respect to financial returns and the determination not to proceed with the project, including project delays, the economic downturn, regulatory and permitting hurdles, a challenging refining environment in California and an industry shift in the outlook for availability of domestic crude oil. We assessed the recoverability of these long-lived assets and, where necessary, performed further analysis based on a projected discounted cash flow methodology. As a result of this impairment review, we wrote off a substantial portion of the carrying amount of these long-lived assets, except for the portion that we anticipate we will recover. These project assets were included in our Facilities segment.

Also in 2012, we recognized a loss on impairment as a result of our decision to sell certain refined products pipeline systems and related assets included in the Transportation segment. At December 31, 2012, these assets were classified as held for sale on our Consolidated Balance Sheet (in Other current assets). In accordance with GAAP, we wrote their book value down to their expected sales price. In February 2013, we signed a definitive agreement to sell these systems and related assets. A portion of the transaction closed in July 2013 and we closed the balance of the transaction in November 2013.

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Note 7 Goodwill

Goodwill represents the future economic benefits arising from assets acquired in a business combination that are not individually identified and separately recognized.

In accordance with FASB guidance, we test goodwill at least annually (as of June 30) and on an interim basis if a triggering event occurs, such as an adverse change in business climate, to determine whether impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is an operating segment or one level below an operating segment for which discrete financial information is available and regularly reviewed by segment management. Our reporting units are our operating segments.
FASB guidance requires a two-step, quantitative approach to testing goodwill for impairment; however, we may first assess certain qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. We did not elect to apply this qualitative assessment during our 2013 annual goodwill impairment test, but proceeded directly to the two-step, quantitative test. In Step 1, we compare the fair value of the reporting unit with the respective book values, including goodwill, by using an income approach based on a discounted cash flow analysis. This approach requires us to make long-term forecasts of future revenues, expenses and other expenditures. Those forecasts require the use of various assumptions and estimates, the most significant of which are net revenues (total revenues less purchases and related costs), operating expenses, general and administrative expenses and the weighted average cost of capital. Fair value of the reporting units is determined using significant unobservable inputs, or level 3 inputs in the fair value hierarchy. When the fair value is greater than book value, then the reporting unit s goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit s goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value.

Through Step 1 of our annual testing of goodwill for potential impairment, which also includes a sensitivity analysis regarding the excess of our reporting unit s fair value over book value, we determined that the fair value of each reporting unit was substantially greater than its respective book value, and therefore goodwill was not considered impaired. We will continue to monitor various potential indicators (including the financial markets) to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary.

The table below reflects our goodwill by segment and changes during the periods presented (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Balance at December 31, 2011	$ 818	$ 609	$ 427	$ 1,854
2012 Goodwill Related Activity:				
BP NGL Acquisition	72	136	28	236
USD Rail Terminal Acquisition		426		426
Other acquisitions	10			10
Foreign currency translation adjustments	5		2	7
Purchase price accounting adjustments and other	(8)		10	2
Balance at December 31, 2012	$ 897	$ 1,171	$ 467	$ 2,535
2013 Goodwill Related Activity:				
Acquisitions (1)	6			6
Foreign currency translation adjustments	(20)	(9)	(4)	(33)
	(5)			(5)

Purchase price accounting adjustments and other (1)				
Balance at December 31, 2013	$ 878	$ 1,162	$ 463	$ 2,503

(1) Goodwill is recorded at the acquisition date based on a preliminary fair value determination. This preliminary goodwill balance may be adjusted when the fair value determination is finalized. See Note 3 for additional discussion of our acquisitions.

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Note 8 Other Assets, Net

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

	December 31, 2013	December 31, 2012
Deferred tax asset	$ 1,068	$
Debt issue costs	72	70
Fair value of derivative instruments	30	10
Intangible assets	674	642
Other	37	54
	1,881	776
Accumulated amortization	(271)	(189)
	$ 1,610	$ 587

In connection with the transfer of the ownership interest in AAP in connection with our IPO in October 2013 and any subsequent transfers in 2013, a deferred tax asset was created. See Note 12 for further discussion.

Costs incurred in connection with the issuance of long-term debt and amendments to credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the effective interest method of amortization. Fully amortized debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized debt issue costs of approximately $10 million and $21 million in 2013 and 2012, respectively. Approximately $8 million and $5 million of gross debt issue costs, primarily related to the restructuring of credit facilities, were removed from our Consolidated Balance Sheet during 2013 and 2012, respectively.

Amortization expense related to other assets (including finite-lived intangible assets) for the three years ended December 31, 2013, 2012 and 2011 was approximately $96 million, $99 million and $44 million, respectively. Our amortization expense for finite-lived intangible assets for the years ended December 31, 2013, 2012 and 2011 was approximately $85 million, $90 million and $36 million, respectively.

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

[redacted]

Customer contracts and relationships	1 - 20	$ 591	$ (237)	$ 354	$ 558	$ (157)	$ 401
Property tax abatement	7 - 13	38	(14)	24	38	(10)	28
Other agreements	25 - 70	37	(3)	34	38	(2)	36
Emission reduction credits (1)	N/A	8		8	8		8

	$ 674	$ (254)	$ 420	$ 642	$ (169)	$ 473

(1) Emission reduction credits, once surrendered in exchange for environmental permits, are finite-lived.

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

2014	$ 59
2015	$ 52
2016	$ 45
2017	$ 42
2018	$ 36

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Note 9 Debt

Debt consisted of the following as of the dates indicated (in millions):

	December 31, 2013	December 31, 2012
SHORT-TERM DEBT		
Credit Facilities (1):		
PAA senior secured hedged inventory facility, bearing a weighted-average interest rate of 1.6% at December 31, 2012 (2)	$	$ 665
PAA senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.4% at December 31, 2012 (2)		92
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% at December 31, 2012 (3)		77
PAA commercial paper notes, bearing a weighted-average interest rate of 0.33% at December 31, 2013 (2)	1,109	
PAA 5.63% senior notes due December 2013		250
Other	4	2
Total short-term debt	1,113	1,086
LONG-TERM DEBT		
PAA Senior Notes:		
5.25% senior notes due June 2015	150	150
3.95% senior notes due September 2015	400	400
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	350
5.75% senior notes due January 2020	500	500
5.00% senior notes due February 2021	600	600
3.65% senior notes due June 2022	750	750
2.85% senior notes due January 2023	400	400
3.85% senior notes due October 2023	700	
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
5.15% senior notes due June 2042	500	500
4.30% senior notes due January 2043	350	350
Unamortized discounts	(15)	(15)
PAA senior notes, net of unamortized discounts	6,710	6,010
Credit Facilities and Other Long-Term Debt (1):		
AAP term loan, bearing a weighted-average interest rate of 1.9% and 1.8% at December 31, 2013 and December 31, 2012, respectively	500	200
AAP senior secured revolving credit facility, bearing a weighted-average interest rate of 2.2% at December 31, 2013	15	
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% at December 31, 2012 (3)		105
PNG GO Bond term loans, bearing a weighted-average interest rate of 1.5% at December 31, 2012 (3)		200
Other	5	5
Total long-term debt	7,230	6,520
Total debt (2) (3) (4)	$ 8,343	$ 7,606

(1) During 2013 and 2012, we renewed, extended or refinanced our principal bank credit facilities. See Credit Facilities below for further discussion.

(2) We classify as short-term certain borrowings under the PAA commercial paper program, PAA senior unsecured revolving credit facility and PAA senior secured hedged inventory facility. These borrowings are primarily designated as working capital borrowings, must be repaid within one year and are primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

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(3) On December 31, 2013, in connection with the completion of the PNG Merger, all of PNG s outstanding debt obligations were repaid and terminated.

(4) PAA s fixed-rate senior notes (including current maturities) had a face value of approximately $6.7 billion and $6.3 billion as of December 31, 2013 and 2012, respectively. We estimated the aggregate fair value of these notes as of December 31, 2013 and 2012 to be approximately $7.2 billion and $7.3 billion, respectively. PAA s fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near year end. We estimate that the carrying value of outstanding borrowings under credit facilities and agreements and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for both the senior notes and credit facilities are based upon observable market data and are classified within Level 2 of the fair value hierarchy.

Commercial Paper Program

In August 2013, PAA established a commercial paper program under which it may issue, from time to time, privately placed, unsecured commercial paper notes for up to a maximum aggregate amount outstanding at any time of $1.5 billion. Such notes are backstopped by the PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory facility; as such, any borrowings under the PAA commercial paper program reduce the available capacity under these facilities.

Credit Facilities

PAA senior secured hedged inventory facility. In August 2013, PAA amended its senior secured hedged inventory facility agreement to, among other things, extend the maturity date of the facility by two years to August 2016. The agreement also provides for one or more one-year extensions, subject to applicable approval. The facility has a committed borrowing capacity of $1.4 billion, of which $400 million is available for the issuance of letters of credit. Subject to obtaining additional or increased lender commitments, the committed amount of the facility may be increased to $1.9 billion. Proceeds from the facility are being used to finance purchased or stored hedged inventory. Obligations under the committed facility are secured by the financed inventory and the associated accounts receivable and will be repaid from the proceeds of the sale of the financed inventory. Borrowings accrue interest based, at PAA s election, on either the Eurocurrency Rate or the Base Rate, in each case plus a margin based on PAA s credit rating at the applicable time.

PAA senior unsecured revolving credit facility. In August 2013, PAA amended its senior unsecured revolving credit facility agreement to, among other things, extend the maturity date by two years to August 2018. The agreement also provides for one or more one-year extensions, subject to applicable approval. The facility has a committed borrowing capacity of $1.6 billion which contains an accordion feature that enables us to increase the committed capacity to $2.1 billion, subject to obtaining additional or increased lender commitments. The credit agreement also provides for the issuance of letters of credit. Borrowings accrue interest based, at PAA s election, on the Eurocurrency Rate, the Base Rate or the Canadian Prime Rate, in each case plus a margin based on PAA s credit rating at the applicable time.

AAP senior secured credit agreement. In September 2013, the AAP credit agreement was amended to increase the term loan facility from $200 million to $500 million, increase the aggregate commitments under the revolving credit facility from $25 million to $75 million and extend the maturity date by one year to September 2018. We pay a quarterly commitment fee on the revolver that is based on AAP s Consolidated

Indebtedness to Consolidated EBITDA ratio (Leverage Ratio), as defined in the credit agreement. The commitment fee can range from 0.175% to 0.35% and is payable on the daily average unused amount of the revolver. Borrowings accrue interest based, at AAP s election, on the Alternative Base Rate (the greater of the Base Rate or Federal Funds Effective Rate) or the Eurodollar Rate, in each case plus a margin as determined by AAP s Leverage Ratio.

PNG senior unsecured credit agreement. The PNG senior unsecured credit agreement provided for (i) $350 million under a revolving credit facility and (ii) two $100 million GO Bond term loans. PNG s revolving credit facility included the ability to issue letters of credit. Borrowings under the revolving credit facility accrued interest, at PNG s election, on either the Eurodollar Rate or the Base Rate, in each case plus an applicable margin. The GO Bond term loans accrued interest in accordance with the interest payable on the related GO Bonds purchased with respect thereto as provided in such GO Bonds and the GO Bonds Indenture pursuant to which such GO Bonds are issued and governed. On December 31, 2013, in connection with the completion of the PNG Merger, all outstanding borrowings were repaid under the credit facility and the related revolving credit commitments were terminated. PAA retained the effectiveness of the GO Bond Indenture, which may be utilized for a future tax-exempt $200 million debt issuance.

Senior Notes

PAA s senior notes are co-issued, jointly and severally, by Plains All American Pipeline, L.P. and a 100%-owned consolidated finance subsidiary (neither of which have independent assets or operations) and are unsecured senior obligations of such entities and rank equally in right of payment with existing and future senior indebtedness of the issuers. PAA may, at its option, redeem any series of senior notes at any time in whole or from time to time in part, prior to maturity, at the redemption prices described in the indentures governing the senior notes. In August 2011, as permitted under the indentures governing the senior notes, PAA released the guarantees of each subsidiary guarantor. As such, PAA s senior notes are not guaranteed by any of its subsidiaries.

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Senior Notes Issuances

In August 2013, PAA completed the sale and issuance of $700 million, 3.85% senior notes due October 15, 2023. The senior notes were sold at 99.792% of face value. Interest payments are due on April 15 and October 15 each year beginning on April 15, 2014.

In December 2012, PAA completed the sale and issuance of $400 million, 2.85% senior notes due January 31, 2023 and $350 million, 4.30% senior notes due January 31, 2043. The senior notes were sold at 99.752% and 99.925% of face value, respectively. Interest payments are due on January 31 and July 31 each year, which began on July 31, 2013.

In March 2012, PAA completed the sale and issuance of $750 million, 3.65% senior notes due June 1, 2022 and $500 million, 5.15% senior notes due June 1, 2042. The senior notes were sold at 99.823% and 99.755% of face value, respectively. Interest payments are due on June 1 and December 1 each year, which began on December 1, 2012.

Senior Note Repayments and Redemptions

On December 13, 2013, PAA repaid its $250 million, 5.63% senior notes. PAA utilized cash on hand and available capacity under its commercial paper program to repay these notes.

On September 4, 2012, PAA repaid its $500 million, 4.25% senior notes. PAA utilized cash on hand and available capacity under its credit facilities to repay these notes.

On February 7, 2011, PAA s $200 million 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million, recorded to Other income/(expense), net in our Consolidated Statement of Operations. PAA utilized cash on hand and available capacity under its credit facilities to redeem these notes.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2013 was approximately 11 years and the aggregate maturities for the next five years and thereafter are as follows (in millions):

Calendar Year	**Payment**
2014	$

2015		550
2016		175
2017		400
2018		1,115
Thereafter		5,000
Total (1)	$	7,240

(1) Excludes aggregate unamortized net discount of approximately $15 million and other long-term obligations of approximately $5 million.

Covenants and Compliance

PAA s Credit Agreements. PAA s credit agreements (which impact the ability to access the PAA commercial paper program) and the indentures governing PAA s senior notes contain cross-default provisions. PAA s credit agreements prohibit declaration or payments of 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 PAA s ability to, among other things:

- grant liens on certain property;
- incur indebtedness, including capital leases;
- sell substantially all of its assets or enter into a merger or consolidation;
- engage in certain transactions with affiliates; and
- enter into certain burdensome agreements.

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The PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory facility treat a change of control as an event of default and also requires PAA to maintain a debt-to-EBITDA coverage ratio that will not be greater than 5.00 to 1.00 (or 5.50 to 1.00 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $150 million)).

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

A default under PAA s credit facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as PAA is in compliance with its credit agreements, PAA s ability to make distributions of available cash is not restricted. As of December 31, 2013, PAA was in compliance with the covenants contained in its credit agreements and indentures.

AAP Credit Agreement. In order to secure the facility, AAP pledged 100% of (i) its incentive distribution rights in PAA and (ii) its interest in PAA GP. The credit agreement contains various covenants limiting AAP s ability to, among other things:

- incur additional indebtedness;
- grant liens;
- make fundamental changes as defined;
- make restrictive payments as defined; and
- enter into restrictive agreements.

The AAP credit agreement requires AAP to maintain a Leverage Ratio of no greater than 4.0 to 1.0.

Borrowings and Repayments

Total borrowings under credit agreements and the commercial paper program for the years ended December 31, 2013, 2012 and 2011 were approximately $31.5 billion, $12.9 billion and $9.7 billion, respectively. Total repayments under credit agreements and the commercial paper program were approximately $31.2 billion, $12.2 billion and $10.9 billion for the years ended December 31, 2013, 2012 and 2011, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. These letters of credit are issued under the PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory facility, and our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil, NGL or natural gas is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs and construction activities. At December 31, 2013 and 2012, we had outstanding letters of credit of approximately $41 million and $24 million, respectively.

Note 10 Partners Capital and Distributions

Initial Public Offering

Through a series of transactions with our general partner and the owners of GP LLC prior to the closing of our IPO, we issued 473,647,679 Class B shares and an equal number of units of our general partner to such owners and received a 100% managing member interest in GP LLC. Also prior to the IPO, certain owners of AAP (the Selling Owners) sold a portion of their interests in AAP to us in exchange for the right to receive an amount equal to the net proceeds of the IPO, resulting in our ownership of AAP units representing limited partnership interests in AAP.

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In October 2013, we completed our IPO of 132,382,094 Class A shares representing limited partner interests at a price of $22.00 per Class A share, generating net proceeds, after deducting underwriting discounts and commissions and direct offering expenses, of approximately $2.8 billion. We distributed the net proceeds of the IPO to the Selling Owners.

Shares Outstanding

Partners capital at December 31, 2013 consists of 133,833,637 Class A shares and 472,196,136 Class B shares outstanding. Our Class A shares and Class B shares represent limited partner interests in us. The holders of our Class A and Class B shares are entitled to exercise the rights or privileges available to limited partners under our partnership agreement, but only holders of Class A shares are entitled to participate in our distributions.

Exchange Rights. Permitted transferees of holders of AAP units will each have the right to exchange all or a portion of their AAP units into Class A shares at an exchange ratio of one Class A share for each AAP unit exchanged. This exchange right may be exercised only if, simultaneously therewith, an equal number of our Class B shares and general partner units are transferred by the exercising party to us. Additionally, if our Class A shares are publicly traded at any time after December 31, 2015, a holder of vested AAP Management Units will be entitled to exchange his or her AAP Management Units for AAP units and a like number of our Class B shares based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and was approximately 0.90 AAP units for each AAP Management Unit as of December 31, 2013). Following any such exchange, the holder will have the Exchange Right for our Class A shares. Holders of AAP Management Units who exchange for AAP units and Class B shares will not receive general partner units and thus will not need to include any general partner units in a transfer or the exercise of their Exchange Right. See Note 15 for additional information regarding the AAP Management Units. A total of 1,451,543 AAP units, Class B shares and general partner units were exchanged through December 31, 2013 for 1,451,543 Class A shares.

The following table sets forth the changes in our outstanding shares since becoming public:

	Class A Shares	Class B Shares
Balance at October 21, 2013 (IPO date)		
Shares issued in connection with the reorganization and IPO	132,382,094	473,647,679
Shares issued/(exchanged) in connection with AAP unit exchanges	1,451,543	(1,451,543)
Balance at December 31, 2013	133,833,637	472,196,136

Distributions

We distribute 100% of our available cash within 55 days after the end of each quarter to Class A shareholders of record. Available cash is generally defined as all cash on hand at the date of determination of available cash for the distribution in respect to such quarter (including expected distributions from AAP in respect of such quarter), less reserves established by our general partner for future requirements.

Distributions to Class A Shareholders. On January 9, 2014, we declared a distribution for the fourth quarter of 2013 of $0.12505 per outstanding Class A share, which was prorated for the partial quarter following the closing of our IPO on October 21, 2013. This distribution of approximately $17 million was paid on February 14, 2014 to shareholders of record at the close of business on January 31, 2014.

Distributions Prior to our IPO. During the years ended December 31, 2013, 2012 and 2011, $6 million, $3 million and $2 million, respectively, were distributed to the owners of GP LLC. Of the amount distributed during the year ended December 31, 2013, approximately $3 million relates to distributions received from AAP related to the net proceeds from the increase in AAP s term loan. See Note 9 for further discussion.

Noncontrolling Interests in Subsidiaries

As of December 31, 2013, noncontrolling interests in subsidiaries consisted of the following: (i) a 98% limited partner interest in PAA, (ii) an approximate 78% limited partner interest in AAP that consists of Class A units and AAP Management Units (a profits interest) and (iii) a 25% interest in SLC Pipeline. Prior to our IPO, noncontrolling interests in subsidiaries consisted of: (i) a 98% limited partner interest in PAA, (ii) a 99% limited partner interest in AAP that consisted of Class A units and AAP Management Units (a profits interest), (iii) an approximate 37% limited partner interest in PNG and (iv) a 25% interest in SLC Pipeline.

PAA Distributions

PAA distributes 100% of its available cash within 45 days after the end of each quarter to unitholders of record and to AAP. Available cash is generally defined as all of PAA s cash and cash equivalents on hand at the end of each quarter, less reserves established by its general partner for future requirements.

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AAP is entitled to receive (i) distributions representing its 2% indirect general partner interest in PAA and (ii) incentive distributions if the amount PAA distributes with respect to any quarter exceeds levels specified in PAA s partnership agreement. Under the quarterly distribution provisions, AAP is entitled, without duplication, to 2% of amounts PAA distributes up to $0.2250 per unit, referred to as the MQD, 15% of amounts PAA distributes in excess of $0.2250 per unit, 25% of the amounts PAA distributes in excess of $0.2475 per unit and 50% of amounts PAA distributes in excess of $0.3375 per unit.

AAP agreed to reduce the amount of its incentive distribution by $3.75 million per quarter for distributions paid during 2013, $6.75 million for the distribution paid in February 2014, $5.5 million per quarter thereafter through November 2015, $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. These reductions were agreed to in connection with the BP NGL Acquisition and the completion of the PNG Merger on December 31, 2013. See Note 3 for further discussion of the BP NGL Acquisition. For distributions paid during the years ended December 31, 2013, 2012 and 2011, AAP s incentive distributions were reduced by approximately $15 million, $11 million and $7 million, respectively.

Total cash distributions paid by PAA during the periods indicated were as follows (in millions, except per unit amounts):

	Distributions Paid				Distributions
	Common	AAP			per limited
Year	Units	Incentive	2%	Total	partner unit
2013	$ 791	$ 353	$ 16	$ 1,160	$ 2.33
2012	$ 684	$ 271	$ 14	$ 969	$ 2.11
2011	$ 575	$ 204	$ 12	$ 791	$ 1.95

On January 9, 2014, PAA declared a cash distribution of $0.6150 per unit on PAA s outstanding common units. The distribution was paid on February 14, 2014 to unitholders of record on January 31, 2014, for the period October 1, 2013 through December 31, 2013. The total distribution paid was approximately $328 million, with approximately $221 million paid to PAA s common unitholders and $5 million and $102 million paid to AAP for its general partner and incentive distribution interests, respectively.

AAP Distributions

AAP distributes all of the cash received from PAA distributions on a quarterly basis, less reserves established in the discretion of its general partner for future requirements. Generally, distributions are paid to its partners in proportion to their percentage interest in the AAP. During the years ended December 31, 2013, 2012 and 2011, AAP distributed approximately $361 million, $276 million and $209 million, respectively, to its partners, related to distributions received from PAA.

In September 2013, the AAP credit agreement was amended to increase the amount of the term loan by $300 million. Upon receipt, the net term loan proceeds of approximately $299 million were distributed to AAP s partners, excluding AAP Management Unit holders, in proportion to their respective ownership interests. See Note 9 for further discussion.

On February 14, 2014, AAP distributed approximately $104 million to its partners. The distribution was prorated as of the date of the consummation of our IPO, such that the Selling Owners received the portion of the distribution attributable to the period of the fourth quarter of 2013 prior to our IPO, and the owners of AAP at the date of record of January 31, 2013, including us, received the portion of the distribution attributable to the period beginning on the date of our IPO through the end of the fourth quarter of 2013.

PAA Equity Offerings

Continuous Offering Program. During 2012 and 2013 PAA entered into several equity distribution agreements, under its Continuous Offering Program, with respect to the offer and sale, through sales agents, of common units representing limited partner interests having aggregate offering prices ranging from up to $300 million to up to $750 million. Sales of such common units are made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by the sales agent and PAA.

During the year ended December 31, 2013, PAA sold an aggregate of approximately 8.6 million common units under its Continuous Offering Program, generating proceeds of approximately $468 million, net of offering costs.

During the year ended December 31, 2012, PAA sold an aggregate of approximately 12.0 million common units under its Continuous Offering Program, generating proceeds of approximately $513 million, net of offering costs.

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Other Equity Offerings. In addition to sales of PAA s common units under its Continuous Offering Program described above, PAA completed the following offerings of its common units during the three years ended December 31, 2013 (in millions, except unit and per unit data):

Period	Units Issued	Gross Unit Price	Proceeds from Sale	Costs	Net Proceeds
March 2012 (1)	11,500,000	$ 40.015	$ 460	$ (14)	$ 446
2012 Total	**11,500,000**		**$ 460**	**$ (14)**	**$ 446**
November 2011 (1)	12,000,000	$ 32.515	$ 390	$ (13)	$ 377
March 2011 (1)	15,870,000	$ 32.000	508	(15)	493
2011 Total	**27,870,000**		**$ 898**	**$ (28)**	**$ 870**

(1) These offerings of common units were underwritten transactions that required PAA to pay a gross spread.

Contributions from Noncontrolling Interests

Contributions from noncontrolling interests consists of contributions from the owners of AAP (other than us) to reimburse AAP for its capital contribution required to maintain its indirect 2% general partner interest in PAA following PAA s issuance of common units.

Issuance of PNG Common Units

PNG issued approximately 1.9 million and 27.6 million common units during the years ended December 31, 2013 and 2011, respectively. PNG did not issue any common units during the year ended December 31, 2012. As a result of PNG s common unit issuances, we recorded an increase in noncontrolling interest of approximately $40 million and $370 million in 2013 and 2011, respectively.

Note 11 Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on hydrocarbon commodity (referred to herein as commodity) price changes. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange rate risk. Our commodity risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our derivative positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and currency exchange rate risk management policies and procedures are designed to monitor our derivative positions and ensure that those positions are consistent with our objectives and approved strategies. When we apply hedge accounting, our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

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Commodity Price Risk Hedging

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use of derivative instruments. Our policy is to (i) only purchase inventory for which we have a market, (ii) structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be divided into the following general categories:

Commodity Purchases and Sales   In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of December 31, 2013, net derivative positions related to these activities included:

- An average of 242,800 barrels per day net long position (total of 7.5 million barrels) associated with our crude oil purchases, which was unwound ratably during January 2014 to match monthly average pricing.

- A net short spread position averaging approximately 13,600 barrels per day (total of 5.4 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through February 2015. These derivatives are time spreads consisting of offsetting purchases and sales between two different months. Our use of these derivatives does not expose us to outright price risk.

- An average of 2,200 barrels per day (total of 1.0 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are priced as a percentage of WTI through March 2015.

- A long position of approximately 2.3 Bcf through April 2016 related to anticipated base gas requirements.

- A short position of approximately 40.5 Bcf through April 2014 related to anticipated sales of natural gas inventory.

- A short position of approximately 6.9 million barrels through March 2015 related to the anticipated sales of our crude oil, NGL and refined products inventory.

Storage Capacity Utilization   We own a significant amount of crude oil, NGL and refined products storage capacity other than that used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk in a backwardated market structure. As of December 31, 2013, we used derivatives to manage the risk of not utilizing approximately 0.8 million barrels per month of storage capacity through February 2014. These positions involve no outright price exposure, but instead enable us to profitably use the capacity to store hedged crude oil.

Pipeline Loss Allowance Oil As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of December 31, 2013, our PLA hedges included a net short position for an average of approximately 1,700 barrels per day (total of 1.2 million barrels) through December 2015 and a long call option position of approximately 0.5 million barrels through December 2015.

Natural Gas Processing/NGL Fractionation As part of our supply and logistics activities, we purchase natural gas for processing and NGL mix for fractionation, and we sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. As of December 31, 2013, we had a long natural gas position of approximately 19.5 Bcf through December 2015, a short propane position of approximately 3.4 million barrels through December 2015, a short butane position of approximately 1.0 million barrels through December 2015 and a short WTI position of approximately 0.4 million barrels through December 2015. In addition, we had a long power position of 0.5 million megawatt hours which hedges a portion of our power supply requirements at our natural gas processing and fractionation plants through June 2016.

All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase normal sale scope exception. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the normal purchase normal sale scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings.

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Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of December 31, 2013, AOCI includes deferred losses of approximately $65 million that relate to open and terminated interest rate derivatives that were designated for hedge accounting. The terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

PAA has entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2015. The following table summarizes the terms of PAA s forward starting interest rate swaps as of December 31, 2013 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	10 forward starting swaps (30-year)	$ 250	6/15/2015	3.60%	Cash flow hedge

Concurrent with PAA s August 2013 senior notes issuance, PAA terminated five thirty-year forward starting interest rate swaps. These swaps had an aggregate notional amount of $125 million and an average fixed rate of 3.39%. We received cash proceeds of approximately $11 million, of which a gain of approximately $8 million was deferred in AOCI and a gain of approximately $3 million was recognized in interest expense attributable to the ineffective portion of these swaps.

Concurrent with PAA s December 2012 senior note issuance, PAA terminated six thirty-year forward starting interest rate swaps. These swaps had an aggregate notional amount of $250 million and an average fixed rate of 4.24%. We made a cash payment of approximately $89 million in connection with the termination of these swaps.

Concurrent with PAA s March 2012 senior note issuances, PAA terminated four ten-year forward starting interest rate swaps. These swaps had an aggregate notional amount of $200 million and an average fixed rate of 3.46%. We made a cash payment of approximately $24 million in connection with the termination of the swaps.

Concurrent with PAA s January 2011 senior notes issuance, PAA terminated three forward starting interest rate swaps. These swaps had an aggregate notional amount of $100 million and an average fixed rate of 3.6%. We received cash proceeds of approximately $12 million in connection with the termination of these swaps.

During June 2011 and August 2011, PNG entered into three interest rate swaps to fix the interest rate on a portion of PNG s outstanding debt. Following the completion of the PNG Merger, these swaps were terminated in conjunction with the termination of the PNG credit facility.

During December 2007 and January 2008, AAP entered into a total of three interest rate swaps to fix the interest rate on a portion of its outstanding debt. These swaps had an aggregate notional amount of $200 million with an average interest rate of 3.99%. Two of these swaps terminated in January 2011 and one terminated in January 2013. These swaps were designated as cash flow hedges.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use foreign currency derivatives to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts and forwards.

As of December 31, 2013, our outstanding foreign currency derivatives include derivatives we use to (i) hedge currency exchange risk associated with USD-denominated commodity purchases and sales in Canada and (ii) hedge currency exchange risk created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

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The following table summarizes our open forward exchange contracts as of December 31, 2013 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2014	$ 336	$ 358	$1.00 - $1.06
	2015	9	9	$1.00 - $1.07
		$ 345	$ 367	$1.00 - $1.06
Forward exchange contracts that exchange USD for CAD:				
	2014	$ 336	$ 354	$1.00 - $1.05
	2015	9	9	$1.00 - $1.06
		$ 345	$ 363	$1.00 - $1.05
Net position by currency:				
	2014	$	$ 4	
	2015			
		$	$ 4	

Summary of Financial Impact

We record all open derivatives on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions are recognized in earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as cash flows from operating activities in our Consolidated Statements of Cash Flows.

A summary of the impact of our derivative activities recognized in earnings for the years ended December 31, 2013, 2012 and 2011 is as follows (in millions):

	Year Ended December 31, 2013			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	**Gain/(loss) reclassified from AOCI into income** (1)	**Other gain/(loss) recognized in income**	**Derivatives Not Designated as a Hedge**	**Total**
Commodity Derivatives				
Supply and Logistics segment revenues	$ 78	$ (1)	$ (116)	$ (39)
Facilities segment revenues	(10)	(1)		(11)
Field operating costs			8	8
Interest Rate Derivatives				

Interest expense	(7)	3		(4)
Foreign Currency Derivatives				
Other income/(expense), net	5			5
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ 66**	**$ 1**	**$ (108)**	**$ (41)**

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	Year Ended December 31, 2012							
	Derivatives in Hedging Relationships							
Location of gain/(loss)		Gain/(loss) reclassified from AOCI into income (1)		Other gain/(loss) recognized in income		Derivatives Not Designated as a Hedge		Total
Commodity Derivatives								
Supply and Logistics segment revenues	$	12	$		$	60	$	72
Facilities segment revenues		3		(1)		1		3
Purchases and related costs		45				1		46
Field operating costs						1		1
Interest Rate Derivatives								
Interest expense		(8)		1				(7)
Foreign Currency Derivatives								
Supply and Logistics segment revenues						(1)		(1)
Other income/(expense), net		6						6
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$**	**58**	**$**		**$**	**62**	**$**	**120**

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	Year Ended December 31, 2011			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(loss) reclassified from AOCI into income (1)	Other gain/(loss) recognized in income	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ (153)	$ (8)	$ 99	$ (62)
Facilities segment revenues	11			11
Purchases and related costs	6			6
Field operating costs			1	1
Interest Rate Derivatives				
Interest expense	(5)	2		(3)
Foreign Currency Derivatives				
Supply and Logistics segment revenues			1	1
Other income/(expense), net	6			6
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ (135)**	**$ (6)**	**$ 101**	**$ (40)**

(1) During the year ended December 31, 2013, we reclassified a gain of approximately $3 million and losses of approximately $1 million from AOCI to Supply and Logistics segment revenues and Facilities segment revenues, respectively, as a result of anticipated hedged transactions that are probable of not occurring. During the year ended December 31, 2011 we reclassified a gain of approximately $1 million from AOCI to Facilities segment revenues and a gain of approximately $1 million from AOCI to other expense, net as a result of anticipated hedged transactions that are probable of not occurring. During the year ended December 31, 2012, all of our hedged transactions were deemed probable of occurring.

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The following table summarizes the derivative assets and liabilities on our Consolidated Balance Sheet on a gross basis as of December 31, 2013 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	36	Other current assets	$	(24)
	Other long-term assets		5			
Interest rate derivatives	Other long-term assets		26			
Total derivatives designated as hedging instruments		$	67		$	(24)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	60	Other current assets	$	(117)
	Other long-term assets		5	Other long-term assets		(6)
	Other current liabilities		1	Other current liabilities		(5)
				Other long-term liabilities		(1)
Foreign currency derivatives				Other current liabilities		(4)
Total derivatives not designated as hedging instruments		$	66		$	(133)
Total derivatives		$	133		$	(157)

The following table summarizes the derivative assets and liabilities on our Consolidated Balance Sheet on a gross basis as of December 31, 2012 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	45	Other current assets	$	(23)
	Other long-term assets		11	Other long-term assets		(1)
Interest rate derivatives				Other long-term liabilities		(38)
Total derivatives designated as hedging instruments		$	56		$	(62)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	128	Other current assets	$	(115)
	Other long-term assets		1	Other long-term assets		(3)
	Other current liabilities		4	Other current liabilities		(7)
	Other long-term liabilities		2	Other long-term liabilities		(2)

Total derivatives not designated as hedging instruments	$	135	$	(127)
Total derivatives	$	191	$	(189)

Our derivative transactions are governed through ISDA (International Swaps and Derivatives Association) master agreements and clearing brokerage agreements. These agreements include stipulations regarding the right of set off in the event that we or our counterparty default on our performance obligations. If a default were to occur, both parties have the right to net amounts payable and receivable into a single net settlement between parties.

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Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of December 31, 2013, we had a net broker receivable of approximately $161 million (consisting of initial margin of $85 million increased by $76 million of variation margin that had been posted by us). As of December 31, 2012, we had a net broker receivable of approximately $41 million (consisting of initial margin of $69 million reduced by $28 million of variation margin that had been returned to us).

The following tables present information about derivatives and financial assets and liabilities that are subject to offsetting, including enforceable master netting arrangements at December 31, 2013 and December 31, 2012 (in millions):

	December 31, 2013		December 31, 2012	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 133	$ (157)	$ 191	$ (189)
Netting adjustment	(148)	148	(148)	148
Cash collateral paid/(received)	161		41	
Net position - asset/(liability)	$ 146	$ (9)	$ 84	$ (41)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 116	$	$ 76	$
Other long-term assets	30		8	
Other current liabilities		(8)		(3)
Other long-term liabilities		(1)		(38)
	$ 146	$ (9)	$ 84	$ (41)

As of December 31, 2013, there was a net loss of approximately $77 million deferred in AOCI including tax effects. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at December 31, 2013, we expect to reclassify a net loss of approximately $10 million to earnings in the next twelve months. The remaining deferred loss of approximately $67 million is expected to be reclassified to earnings through 2045. A portion of these amounts are based on market prices as of December 31, 2013; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The net deferred gain/(loss), including tax effects, recognized in AOCI for derivatives for the three years ended December 31, 2013 are as follows (in millions):

	Year Ended December 31,		
	2013	2012	2011
Commodity derivatives, net	$ 38	$ 56	$ (18)
Interest rate derivatives, net	72	(13)	(137)
Total	$ 110	$ 43	$ (155)

At December 31, 2013 and December 31, 2012, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings. Although we may be required to post margin on our cleared derivatives as described above, we do not require our non-cleared derivative counterparties to post collateral with us.

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Recurring Fair Value Measurements

Derivative Financial Assets and Liabilities

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and December 31, 2012 (in millions):

	Fair Value as of December 31, 2013				Fair Value as of December 31, 2012			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 16	$ (59)	$ (3)	$ (46)	$ 1	$ 35	$ 4	$ 40
Interest rate derivatives		26		26		(38)		(38)
Foreign currency derivatives		(4)		(4)				
Total net derivative asset/(liability)	$ 16	$ (37)	$ (3)	$ (24)	$ 1	$ (3)	$ 4	$ 2

(1) Derivative assets and liabilities are presented above on a net basis but do not include related cash margin deposits.

Level 1

Level 1 of the fair value hierarchy includes exchange-traded commodity derivatives such as futures and options. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets.

Level 2

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity, interest rate and foreign currency derivatives that are traded in active markets. The fair value of these derivatives is based on broker price quotations which are corroborated with market observable inputs.

Level 3

Level 3 of the fair value hierarchy includes over-the-counter commodity derivatives that are traded in markets that are active but not sufficiently active to warrant level 2 classification in our judgment and certain physical commodity contracts. The fair value of our level 3 over-the-counter commodity derivatives is based on broker price quotations. The fair value of our level 3 physical commodity contracts is based on a valuation model utilizing broker-quoted forward commodity prices, and timing estimates, which involve management judgment. The significant unobservable inputs used in the fair value measurement of our level 3 derivatives are forward prices obtained from brokers. A significant increase (decrease) in these forward prices would result in a proportionately lower (higher) fair value measurement.

Rollforward of Level 3 Net Asset/ (Liability)

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

	Year Ended December 31, 2013	2012
Beginning Balance	$ 4	$ 12
Total gains/(losses) for the period:		
Included in earnings **(1)**	(1)	(3)
Included in other comprehensive income		3
Settlements	(3)	(22)
Derivatives entered into during the period	(3)	23
Transfers out of level 3		(9)
Ending Balance	$ (3)	$ 4
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ (4)	$ 24

(1) We reported unrealized gains and losses associated with level 3 commodity derivatives in our Consolidated Statements of Operations as Supply and Logistics segment revenues.

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During the third quarter of 2012, we transferred commodity derivatives with an aggregate fair value of a $14 million gain from level 3 to level 2. These derivatives consist of over the counter derivatives that were previously valued using forward prices obtained from a broker and are now being valued using unadjusted quoted prices in active markets. Our policy is to recognize transfers between levels as of the beginning of the reporting period in which the transfer occurred.

During the second quarter of 2012, we transferred commodity derivatives with an aggregate fair value of a $5 million loss from level 3 to level 2. These derivatives consist of NGL derivatives that are cleared through the CME Clearport platform. This transfer resulted from additional analysis regarding the CME s pricing methodology.

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

Note 12 Income Taxes

We estimate (i) income taxes in the jurisdictions in which we operate, (ii) net deferred tax assets and liabilities based on temporary differences that are expected to be recovered or settled at the enacted tax rates expected in future periods, (iii) valuation allowances for deferred tax assets and (iv) contingent tax liabilities for estimated exposures related to our current tax positions.

Pursuant to FASB guidance related to accounting for uncertainty in income taxes, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the tax position and also the past administrative practices and precedents of the taxing authority. As of December 31, 2013 and 2012, we had not recognized any material amounts in connection with uncertainty in income taxes.

U.S. Federal and State Taxes

Although we are organized as a limited partnership, we have elected to be treated as a corporation for U.S. federal income tax purposes and are therefore subject to both U. S. federal and state income taxes.

Canadian Federal and Provincial Taxes

All of our Canadian operations are conducted within entities that are treated as corporations for Canadian tax purposes (flow through for U.S. tax purposes) and that are subject to Canadian federal and provincial taxes. Additionally, payments of interest and dividends from our Canadian entities to other Plains entities are subject to Canadian withholding tax that is treated as income tax expense.

Tax Components

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

	Year Ended December 31,		
	2013	2012	2011
Current tax expense:			
State income tax	$ 1	$ 2	$ 2
Canadian federal and provincial income tax	99	52	36
Total current tax expense	$ 100	$ 54	$ 38
Deferred tax (benefit)/expense:			
Federal income tax	$ 7	$	$
State income tax			(2)
Canadian federal and provincial income tax	(1)	1	9
Total deferred tax (benefit)/expense	$ 6	$ 1	$ 7
Total income tax expense	$ 106	$ 55	$ 45

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

	Year Ended December 31, 2013		2012		2011	
Income before tax	$	1,480	$	1,173	$	1,032
Net income attributable to noncontrolling interest		(1,359)		(1,115)		(985)
Income taxes attributable to noncontrolling interest		(99)		(55)		(45)
	$	22	$	3	$	2
Federal statutory income tax rate		35%		0%		0%
Income tax at statutory rate	$	8	$		$	
Federal benefit of state income taxes	$	(1)	$		$	
Income taxes attributable to noncontrolling interest:						
Canadian federal and provincial income taxes		79		35		33
Canadian withholding taxes		19		18		12
State income tax		1		2		
Total income tax expense	$	106	$	55	$	45

Deferred tax assets and liabilities are aggregated by the applicable tax paying entity and jurisdiction and presented in Other long-term assets and net in Other long-term liabilities and deferred credits on our Consolidated Balance Sheet and result from the following (in millions):

	December 31, 2013		2012	
Deferred tax assets:				
Investment in partnerships	$	1,057	$	
Net operating losses		11		
Book accruals in excess of current tax deductions		56		28
Total deferred tax assets		1,124		28
Deferred tax liabilities:				
Property and equipment in excess of tax values		(398)		(397)
Total deferred tax liabilities		(398)		(397)
Net deferred tax assets / (liabilities)	$	726	$	(369)
Balance sheet classification of deferred tax assets / (liabilities):				
Other long-term assets	$	1,068	$	
Other long-term liabilities and deferred credits		(342)		(369)
	$	726	$	(369)

In connection with the transfer of the ownership interest in AAP in connection with our IPO in October 2013 and any subsequent transfers in 2013, a deferred tax asset was created. These transfers were accounted for at the historical carrying basis for U.S. GAAP accounting purposes, but were recorded at the value of the consideration paid for U.S. federal income tax purposes. The resulting basis difference resulted in a deferred tax asset that was recorded as a component of partners capital as it results from transactions among shareholders. The deferred tax asset is amortized to deferred income tax expense as the associated basis step-up is realized on our tax returns.

Generally, tax returns for our Canadian entities are open to audit from 2009 through 2013. Our U.S. and state tax years are generally open to examination from 2010 to 2013.

Note 13 Major Customers and Concentration of Credit Risk

Marathon Petroleum Corporation and its subsidiaries accounted for approximately 15% of our revenues for the year ended December 31, 2013 and approximately 16% of our revenues for each of the years ended December 31, 2012 and 2011. ExxonMobil Corporation and its subsidiaries accounted for approximately 13%, 13% and 10% of our revenues for the years ended December 31, 2013, 2012 and 2011, respectively. Phillips 66 and its subsidiaries accounted for approximately 11% of our revenues for the year ended December 31, 2013. ConocoPhillips Company (prior to the spin-off of Phillips 66, which was effective May 1, 2012) accounted for approximately 10% of our revenues for the year ended December 31, 2011. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2013. The majority of revenues from these customers pertain to our supply and logistics operations. The sales to these customers occur at multiple locations and we believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL and natural gas storage. This industry concentration has the potential to impact our overall exposure to credit risk in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered creditworthy, unless the credit risk can otherwise be reduced. See Note 2 for additional discussion of our accounts receivable and our review of credit exposure.

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Note 14 Related Party Transactions

Occidental Petroleum Corporation

As of December 31, 2013, a subsidiary of Occidental Petroleum Corporation (Oxy) owned approximately 25% of the limited partner interests in AAP and had a representative on the board of directors of GP LLC and our general partner. During the three years ended December 31, 2013, we recognized sales and transportation revenues and purchased petroleum products from companies affiliated with Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market. See detail below (in millions):

	Year Ended December 31, 2013	2012	2011
Revenues	$ 1,309	$ 1,636	$ 2,568
Purchases and related costs	$ 863	$ 557	$ 361

We currently have a netting arrangement with Oxy. Our gross receivable and payable amounts with affiliates of Oxy were as follows (in millions):

	December 31, 2013	2012
Trade accounts receivable and other receivables	$ 133	$ 231
Accounts payable	$ 181	$ 129

Other

We also have transactions with companies in which we hold an investment accounted for under the equity method of accounting (see Note 2 for information related to these investments). We recorded revenues of approximately $33 million and $18 million during the years ended December 31, 2013 and 2012, respectively, primarily associated with sales of crude oil to Eagle Ford Pipeline LLC for its linefill requirements. These sales did not result in any gain for us. Revenues from transactions with our equity method investees in 2011 were immaterial. During the three years ended December 31, 2013, we utilized transportation services provided by these companies. Costs related to these services totaled approximately $79 million, $42 million and $33 million for the years ended December 31, 2013, 2012 and 2011, respectively. These transactions were conducted at posted tariff rates or contracted rates or prices that we believe approximate market. Receivables from our equity method investees totaled approximately $2 million and $8 million at December 31, 2013 and 2012, respectively. Accounts payable to our equity method investees at December 31, 2013 and 2012 were approximately $6 million and $4 million, respectively.

Note 15 Equity-Indexed Compensation Plans

Plains GP Holdings, L.P. Long-Term Incentive Plan

In connection with our IPO in October 2013, our general partner adopted the Plains GP Holdings, L.P. Long-Term Incentive Plan (the PAGP LTIP), which is intended to align the interests of employees and directors with those of our shareholders by providing such employees and directors incentive compensation awards that reward achievement of targeted distribution levels and other business objectives. The PAGP LTIP provides for awards of options, restricted shares, phantom shares and share appreciation rights. Certain awards may also include distribution equivalent rights (DERs), which, subject to applicable vesting criteria, entitle the grantee to a cash payment equal to the cash distribution paid on an outstanding Class A Share. The PAGP LTIP authorizes the issuance of up to 10 million Class A Shares deliverable upon vesting. As of December 31, 2013, no grants or awards had been issued or were outstanding under the PAGP LTIP; however, three of our directors received PAGP LTIP awards for an aggregate of 83,200 phantom Class A shares in February 2014.

PAA Long-Term Incentive Plan Awards

Plains All American 2013 Long-Term Incentive Plan. In November 2013, PAA s common unitholders approved the Plains All American 2013 Long-Term Incentive Plan (the PAA 2013 LTIP), which consolidated PAA s three previous long-term incentive plans (the Plains All American GP LLC 1998 Long-Term Incentive Plan, as amended, the Plains All American 2005 Long-Term Incentive Plan, as amended, and the Plains All American PPX Successor Long-Term Incentive Plan, as amended) into a single plan. The PAA 2013 LTIP authorizes the issuance of an aggregate of approximately 13.1 million PAA common units deliverable upon vesting. Although other types of awards are contemplated under the PAA 2013 LTIP, currently outstanding awards are limited to phantom units, which mature into the right to receive common units of PAA (or cash equivalent) upon vesting. Some awards also include DERs, which, subject to applicable vesting criteria, entitle the grantee to a cash payment equal to the cash distribution paid on an outstanding PAA common unit.

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Plains All American PNG Successor Long-Term Incentive Plan. In conjunction with the PNG Merger on December 31, 2013, PAA s general partner adopted and assumed the PAA Natural Gas Storage, L.P. 2010 Long-Term Incentive Plan (the PNG 2010 LTIP) and changed the plan name to the Plains All American PNG Successor Long-Term Incentive Plan (the PNG Successor LTIP). Additionally, as a result of the PNG Merger, outstanding awards of PNG phantom units issued under the PNG 2010 LTIP were converted into comparable awards of phantom units representing the right to receive PAA common units by applying the Merger Exchange Ratio to each outstanding phantom unit and rounding down to the nearest PAA phantom unit for any fractions. See Note 10 for further discussion of the PNG Merger. The PNG Successor LTIP authorizes the issuance of an aggregate of 1.3 million PAA common units deliverable upon vesting. Although other types of awards are contemplated under the PNG Successor LTIP, currently outstanding awards are limited to phantom units, which mature into the right to receive common units of PAA (or cash equivalent) upon vesting. Some awards also include DERs, which, subject to applicable vesting criteria, entitle the grantee to a cash payment equal to the cash distribution paid on an outstanding PAA common unit.

Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan. PAA s general partner has adopted the Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan (the 2006 Plan) for non-officer employees. The 2006 Plan authorizes the grant of approximately 4.2 million tracking units which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a PAA common unit at the time of vesting.

At December 31, 2013, the following LTIP awards, denominated in PAA units, were outstanding (units in millions):

LTIP Units Outstanding (1) (2)	PAA Distribution Required (3)	Estimated Unit Vesting Date				
		2014	**2015**	**2016**	**2017**	**Thereafter**
8.4	$1.925 - $2.65	1.9	2.1	2.0	1.3	1.1

(1) Approximately 4.5 million of the 8.4 million outstanding PAA LTIP awards also include DERs, of which 3.0 million had vested as of December 31, 2013.

(2) LTIP units outstanding do not include AAP Management Units.

(3) These LTIP awards have performance conditions requiring the attainment of an annualized PAA distribution of between $1.925 and $2.65 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained while the grantee remains employed by us, or the grantee does not meet employment requirements, these awards will be forfeited. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

PAA s LTIP awards include both liability-classified and equity-classified awards. In accordance with FASB guidance regarding share-based payments, the fair value of liability-classified LTIP awards is calculated based on the closing market price of the underlying PAA unit at each balance sheet date and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipients. The fair value of equity-classified LTIP awards is calculated based on the closing market price of the PAA unit on the respective grant dates and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipient. This fair value is recognized as compensation expense over the service period.

PAA s LTIP awards typically contain performance conditions based on the attainment of certain PAA annualized distribution levels and vest upon the later of a certain date or the attainment of such levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered to be probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that the probability assessment changes. This is necessary to bring the accrued obligation associated with these awards up to the level it would be as if we had been accruing for these awards since the grant date. DER awards typically contain performance conditions based on the attainment of certain annualized distribution levels and become earned upon the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. For liability-classified awards, we recognize DER payments in the period the payment is earned as compensation expense. For equity-classified awards, we recognize DER payments in the period it is paid as a reduction of noncontrolling interest in partners capital.

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Our accrued liability at December 31, 2013 related to all outstanding liability-classified PAA LTIP awards and DERs is approximately $98 million, of which approximately $43 million was classified as short-term and approximately $55 million was classified as long-term. These short- and long-term accrued LTIP liabilities are reflected in Accounts payable and accrued liabilities and Other long-term liabilities and deferred credits, respectively, on our Consolidated Balance Sheet. These liabilities include accruals associated with our assessments that an annualized PAA distribution of $2.75 was probable of occurring. At December 31, 2012, the accrued liability was approximately $90 million.

Equity-indexed compensation activity for LTIP awards is summarized in the following table (units in millions):

	PAA Units (1) (3)			PNG Units (2) (4)		
	Units		Weighted Average Grant Date Fair Value per Unit	Units		Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2010	8.8	$	20.85	1.0	$	20.55
Granted	1.0	$	27.53		$	
Vested	(1.4)	$	20.34	(0.1)	$	23.62
Cancelled or forfeited	(0.4)	$	20.99	(0.1)	$	19.20
Outstanding, December 31, 2011	8.0	$	21.77	0.8	$	20.55
Granted	1.5	$	33.90	0.1	$	15.33
Vested	(3.2)	$	19.82		$	23.64
Cancelled or forfeited	(0.3)	$	29.36		$	
Outstanding, December 31, 2012	6.0	$	25.55	0.9	$	17.49
Granted	4.1	$	47.60	0.4	$	17.51
Vested	(1.8)	$	24.79		$	18.88
Cancelled or forfeited (5)	(0.3)	$	36.70	(0.3)	$	21.62
Conversion of PNG unit-denominated awards into PAA unit-denominated awards (6)	0.4	$	40.54	(1.0)	$	16.41
Outstanding, December 31, 2013	8.4	$	36.97		$	

(1) Amounts do not include AAP Management Units.

(2) Amounts include PNG Transaction Grants, which are discussed further below.

(3) Approximately 0.5 million, 1.0 million, and 0.5 million PAA common units were issued net of tax withholding of approximately 0.3 million, 0.5 million and 0.2 million units, in 2013, 2012, and 2011 respectively, in connection with the settlement of vested awards. The remaining 1.0 million, 1.7 million and 0.8 million of awards that vested during 2013, 2012 and 2011 respectively, were settled in cash.

(4) Less than 0.1 million PNG units vested during each of the years ended December 31, 2013 and December 31, 2012.

(5)