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, 2014

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

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

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

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

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 $4.4 billion on June 30, 2014, based on a closing price of $31.99 per Class A share as reported on the New York Stock Exchange on such date.

As of February 18, 2015, there were 210,954,074 Class A shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

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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 growth projects;

- 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, whether from reduced cash flow to fund drilling or the inability to access capital, or other factors;

- 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 effects of competition;

- 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 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;

- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;

- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

- maintenance of PAA s credit rating and ability to receive open credit from suppliers and trade counterparties;

- 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;

- shortages or cost increases of supplies, materials or labor;

- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;

- non-utilization of our assets and facilities;

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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;

- 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 completion of our IPO, certain owners of Plains AAP, L.P. (AAP) transferred a portion of their interests in AAP to us, resulting in our ownership of a limited partnership interest in AAP. As of December 31, 2014, we owned a 34.1% limited partner interest in AAP (a 31.8% economic interest), and the remaining limited partner interests in AAP were 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 IDRs 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. Plains All American GP LLC (GP LLC) is a Delaware limited liability company that owns the general partner interests in AAP. Also, through a series of transactions prior to our IPO with PAA GP Holdings LLC (our general partner) and the owners of 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.

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. 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.

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Partnership Structure and Management

Our general partner manages our operations and activities and is responsible for exercising on our behalf any rights we have as the sole and 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 (PMC). 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, 2014 in both a summarized 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.

(1) Board appointment rights limited to non-management investors that own greater than 10% interest in AAP.

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(1) 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 PMC.

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

(3) 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 0.925 AAP units for each AAP Management Unit as of December 31, 2014. The AAP Management Units are entitled to certain proportionate distributions paid by AAP.

(4) As of December 31, 2014, we owned 34.1% of the membership interests in our general partner, which percentage corresponds to our ownership percentage of AAP units (34.1%, representing a 31.8% economic interest in AAP, including the dilutive effect of the AAP Management Units).

Our Business

As of December 31, 2014, our only cash-generating assets consisted of 206,933,274 AAP units, which represent a 34.1% limited partner interest in AAP (31.8% 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. 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:

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

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- 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 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; and

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

To a lesser extent, PAA also engages in similar activities for natural gas and refined products,

PAA s Competitive Strengths

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

- *Many of PAA s 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 crude oil producing regions and other transportation corridors and are connected, directly or indirectly, with PAA s facilities segment assets. The majority of PAA s facilities segment assets are 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. In addition, PAA s assets include pipeline, rail, barge, truck and storage 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 (including PAA s knowledge of North American crude oil flows), 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.* Since 1998, PAA has completed and integrated over 80 acquisitions with an aggregate purchase price of approximately

$11.6 billion. PAA has also implemented expansion capital projects totaling over $7.8 billion. In addition, considering PAA s investment grade credit rating, liquidity and capital structure, we believe PAA has the financial resources and strength necessary to finance future strategic expansion and acquisition opportunities. As of December 31, 2014, PAA had approximately $2.6 billion of liquidity available, including cash and cash equivalents and availability 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 30 years industry experience, and an average of 18 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 to 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, 2014, AAP had $536 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 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 Intercontinental Exchange (ICE) margin requirements. In certain market conditions, these routine short-term debt levels may increase significantly above baseline levels.

For PAA to maintain its targeted credit profile and achieve growth through acquisitions and expansion capital, 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 expansion capital projects to adjusted EBITDA.

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 its existing business lines and enable PAA to leverage its assets, knowledge and skill sets.

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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)
50% Interest in BridgeTex Pipeline Company, LLC (BridgeTex)	Nov-2014	BridgeTex owns a crude oil pipeline that extends from Colorado City, Texas to East Houston	$	1,088(3)
US Development Group (USD) Crude Oil Rail Terminals	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(4)
Western Refining, Inc. (Western) Pipeline and Storage Assets	Dec-2011	Multi-product storage facility in Virginia and Crude oil pipeline in southeastern New Mexico	$	220(5)
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(6)
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(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) Approximate purchase price of $1.075 billion, net of working capital acquired. PAA accounts for its 50% interest in BridgeTex under the equity method of accounting.

(4) 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.

(5) Includes two transactions with Western.

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

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

Ongoing Acquisition and Investment Activities

Consistent with its business strategy, PAA is continuously engaged in the evaluation of potential acquisitions, joint ventures and capital projects. As a part of these efforts, PAA often engages in discussions with potential sellers or other parties regarding the possible purchase of or investment in 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, the acquisition of or investment in 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 efforts may involve participation by PAA in processes that have been made public and involve a number of potential buyers or investors, 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 parties who are in negotiations with the potential seller or other party. These acquisition and investment efforts often involve assets which, if acquired or constructed, 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 agreement. However, in certain cases in order to protect its business interests or for other reasons, PAA may defer public announcement of a transaction until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential transaction can advance or terminate in a short period of time. Moreover, the closing of any transaction for which PAA has entered into a definitive agreement may 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 or investment efforts will be successful. Although PAA expects the acquisitions and investments 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 Acquisitions involve risks that may adversely affect PAA s business.

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PAA s Expansion Capital 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 expansion capital 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 2015 expansion capital plan is representative of the diversity and balance of its overall project portfolio. The following expansion capital projects are included in PAA s 2015 capital plan as of February 2015:

Basin/Region	Project	2015 Plan Amount (1) ($ in millions)	Description	Projected In-Service Date
Permian	Permian Basin Area Projects	$ 365	Multiple projects to increase and expand our pipeline infrastructure in the Permian Basin, including expansion of trunklines into the Delaware Basin and corresponding looping of the Wink-to-Midland segment of our Basin Pipeline	Various, throughout 2015 and 2016
	Cactus Pipeline	85	310 miles of new crude oil pipeline; 250,000 Bbls/d capacity (to be expanded to 330,000 Bbls/d in 2016) from the Permian Basin to the Eagle Ford Pipeline	2015
[redacted]				
Central / Mid-Continent	Diamond Pipeline	165	440 miles of new crude oil pipeline; 200,000 Bbls/d capacity from Cushing, OK to the Valero Memphis, TN refinery	2017
	Red River Pipeline	80	Approximately 400 miles of new crude oil pipeline; 150,000 Bbls/d	2016

			capacity from Cushing, OK to Longview, TX	
	Cushing Terminal Expansions	25	Addition of 1.4 million barrels of storage capacity	2015
[redacted]				
West Coast	Line 63 Reactivation	30	Reactivation of 71 miles of idled pipeline and supporting assets	2015
[redacted]				

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Other	Rail Terminal Projects	240	Railcar purchases and projects located in or near St. James, LA and Kerrobert, Canada	2015
	Other Projects	400		
		$ 1,850		

(1) Represents the portion of the total project cost expected to be incurred during the year. Potential variation to current capital costs estimates may result from (i) changes to project design, (ii) final cost of materials and labor and (iii) timing of incurrence of costs due to uncontrollable factors such as permits, regulatory approvals and weather.

Global Petroleum Market Overview

Crude oil and NGL are two primary components of the world petroleum market, and world economic growth is a major driver of such market. The challenging global economic climate of the last several years resulted in continued uncertainty in the petroleum market. Over the last six months of 2014, global production growth outpaced global consumption growth resulting in lower energy prices. Currently, the United States and Canada comprise 5% of the world s population, generate approximately 20% of the world s petroleum production, and consume approximately 23% of the world s petroleum production. The table below depicts historical and projected production and consumption of liquid fuels for the United States and Canada and the rest of the world and is derived from the EIA Short-Term Energy Outlook, January 2015 (see EIA website at *www.eia.doe.gov*):

	Annual Liquids Production (1)				Projected		Δ from 2011
	2011	2012	2013	2014	2015	2016	2014
	(in millions of barrels per day)						
Production (Supply)							
U.S. & Canada	13.7	15.0	16.5	18.3	19.3	20.0	4.6
Rest of the World	74.2	74.8	73.7	73.8	73.7	73.5	(0.4)
Total (2)	87.9	89.8	90.2	92.2	93.0	93.5	4.3

	Annual Liquids Consumption (1)				Projected		Δ from 2011
	2011	2012	2013	2014	2015	2016	2014
	(in millions of barrels per day)						
Consumption (Demand)							
U.S. & Canada	21.2	20.8	21.4	21.4	21.7	21.8	0.2
Rest of the World	67.3	68.3	69.1	70.0	70.7	71.6	2.7
Total (2)	88.5	89.1	90.5	91.4	92.4	93.4	2.9
U.S. & Canada Production as % of World Production (2)	16%	17%	18%	20%	21%	21%	4%
U.S. & Canada Consumption as % of World Consumption (2)	24%	23%	24%	23%	23%	23%	0%
Net U.S. & Canada (Consumption) (2)	(7.4)	(5.8)	(4.8)	(3.1)	(2.4)	(1.8)	4.4
	(0.6)	0.6	(0.3)	0.8	0.6	0.1	1.3

Global Supply/Demand
Balance

(1) The 2014 amounts are derived from the EIA s Short-Term Energy Outlook.

(2) Amounts may not recalculate due to rounding.

For the period from 2011 through 2014, global liquids production increased 4.3 million barrels per day while global liquids consumption only increased 2.9 million barrels per day. U.S. and Canadian production growth of 4.6 million barrels per day during this period has not only offset a 0.4 million barrels per day decline in production for the rest of the world but also has supplied the 2.9 million barrels per day increase in global demand. This surge in liquids production without a commensurate increase in demand has led to a near to medium-term supply imbalance, which has further led to a reduction in benchmark petroleum prices. The lower prices are leading producers to scale back capital programs, which we believe should ultimately slow down the supply growth and contribute toward bringing the markets back to equilibrium.

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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, 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.

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 completion 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 have the potential to continue to increase if supported by crude oil prices. Increased production has come from both mature producing areas such as the Rockies, the Permian Basin in West Texas and the Mid-Continent region, as well as from less mature, but rapidly growing areas such as the Eagle Ford Shale in South Texas and the Bakken Shale in North Dakota. As a result, North American liquids production increased 4.6 million barrels per day or 34% between 2011 and 2014, 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 have strained 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.

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 oil 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. These previously imported barrels have been absorbed by the rest of the world until recently, when total liquids supply began increasing faster than demand.

Since reaching a multi-year low in 2009, U.S. net refinery inputs of crude oil have slowly increased to a level of 15.8 million barrels per day for the twelve month period ended November 2014, 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.

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The table below shows the overall domestic petroleum consumption projected through 2016 and is derived from the EIA Short-Term Energy Outlook, January 2015 (see EIA website at *www.eia.doe.gov*). 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)	
	2014	2015	2016
	(In millions of barrels per day)		
Supply			
Domestic Crude Oil Production	8.6	9.3	9.5
Net Imports - Crude Oil from Canada	3.2	3.4	3.4
Net Imports - Crude Oil from Other	3.8	3.0	2.9
Other (Supply Adjustment/Stock Change)	0.1	0.2	0.1
Crude Oil Input to Domestic Refineries	15.8	15.9	16.0
Net Product Imports / (Exports)	(1.9)	(2.2)	(2.4)
Supply from Renewable Sources	1.1	1.1	1.1
Other - (NGL Production, Refinery Processing Gain)	4.1	4.5	4.8
Total Domestic Petroleum Consumption	19.1	19.3	19.4

(1) Amounts may not recalculate due to rounding.

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 2014 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)	0.0	1.1	(1.0)
PADD II (Midwest)	1.7	3.5	(1.9)
PADD III (South)	5.1	8.2	(3.1)
PADD IV (Rockies)	0.6	0.6	0.0
PADD V (West Coast)	1.1	2.4	(1.3)
Total U.S.	8.6	15.8	(7.3)

(1) Amounts may not recalculate 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:

- continued development of North American resource plays;
- 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;

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- 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) 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.

Processed Condensate Market

During 2014, the U.S. Department of Commerce, Bureau of Industry and Security (BIS) clarified that processed condensate may be eligible to export if certain criteria are met. In response to our request for clarification, the BIS issued a letter to us stating that the distillation processes employed by PAA at its Gardendale facility satisfies the conditions of the BIS to convert lease condensate into an exportable petroleum product. Per the EIA, lease condensate production (which the EIA generally defines as light liquid hydrocarbons recovered from lease separators or field facilities) has risen from 488,000 barrels per day in 2009 to 852,000 barrels per day in 2013 through the development of the domestic unconventional resource plays. Texas currently yields approximately one-half of the U.S. lease condensates per the EIA.

Refined Products Market Overview

After transport to a refinery, 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.

After crude oil is refined into gasoline and other petroleum products, the products are distributed to consumers or sent further downstream for additional processing in petrochemical or specialty chemical facilities. 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 2011 through November 2014, petroleum consumption has remained relatively flat averaging approximately 18.8 million barrels per day. During this period, as production from domestic resource plays increased, less expensive alternative crude sources have provided domestic refineries with a competitive advantage. This has allowed refineries to increase crude runs from lows of 13.7 million barrels per day in February 2011 to highs of 16.5 million barrels per day in July 2014 with the incremental refined products produced primarily going to export markets. The increased domestic refinery runs combined with flat domestic demand has allowed the U.S. to become a net exporter of refined products versus a historical net importer. Refined product imports decreased from 3.2 million barrels per day in 2005 to an average of approximately 1.7 million barrels per day for the 12 months ended November 2014. Conversely, refined product exports increased from approximately 1.1 million barrels per day in 2005 to 3.1 million barrels per day for the 12 months ended November 2014.

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 and butane, which liquefy at moderate pressures thus making it easier to transport and store such products as compared to ethane. 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 78%) 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.

The majority of gas processing plants in the United States are located along the Gulf Coast, in the West Texas/Oklahoma area, the Marcellus and Utica region and in the Rockies region. 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 18% 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 4% 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.

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. The growth of shale based production in both traditional and new producing areas has resulted in a significant increase in NGL supplies from gas processing plants over the past several years. This has driven extensive expansion and new development of midstream infrastructure in Canada, the Bakken, Marcellus/Utica, and throughout Texas.

The growth of production in non-traditional producing regions has shifted regional basis relationships and the creation of new logistics and infrastructure opportunities. Growing NGL production has meant expansion into new markets, through exports or increased petrochemical demand. The continuation of a relatively low ratio of North American gas and NGL prices to world-wide crude oil prices will mean North American NGL can continue to be competitive on a world scale, either as feedstock for North American based manufacturing or export to overseas markets. In addition to substantially increased exports, 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 enjoyed a supply cost advantage on a world scale.

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While a short term price drop may stunt production growth, the fundamentals of an accessible resource base and improved midstream infrastructure should mean producers can continue to develop the most economic new supply and be ready to go back to rapid growth as prices recover. 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;
- 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) a shift from Gulf of Mexico production to Northeast production causing less concern over disruptions from tropical weather, (iii) increased availability of storage capacity, (iv) a reduction in overall market depth due to various companies exiting the physical gas marketing business and (v) lower basis differentials in certain regions due to expansion and improved connectivity of natural gas transportation infrastructure over the last five 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.

Projected seasonal spreads for the next few years reflect a directionally similar picture to the challenging market conditions we have experienced during most of the past few years. Continuation of these unfavorable market conditions will adversely impact our hub services activities as well as the 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 storage agreements.

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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. We have 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. The map below highlights our more significant assets (including certain assets under construction or development) as of December 31, 2014:

Following is a description of the activities and assets for each of our three 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 pipeline capacity agreements and other transportation fees. Our transportation segment also includes equity earnings from our investments in Settoon Towing and the White Cliffs, Eagle Ford, BridgeTex, Butte and Frontier pipeline systems, in which we own interests ranging from 22% to 50%. We account for these investments under the equity method of accounting.

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As of December 31, 2014, 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:

- 17,800 miles of active crude oil and NGL pipelines and gathering systems;
- 29 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 800 trailers (primarily in Canada); and
- 149 transport and storage barges and 72 transport tugs through our interest in Settoon Towing.

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, 2014, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	**System Miles**	**2014 Average Net Barrels per Day (2) (in thousands)**
United States Crude Oil Pipelines		
Permian Basin		
Basin / Mesa / Sunrise	682	733
BridgeTex (3)	408	14
Permian Basin Area Systems	2,838	765
Permian Basin Subtotal	3,928	1,512
South Texas/Eagle Ford		
Eagle Ford Area Systems	470	227
Western		
All American	138	37
Line 63 / Line 2000	342	122
Other	122	101
Western Subtotal	602	260
Rocky Mountain		
Bakken Area Systems	1,025	149
Salt Lake City Area Systems	969	136
White Cliffs (3)	1,054	30
Other	1,304	111
Rocky Mountain Subtotal	4,352	426

Gulf Coast		
Capline (3)	631	152
Other	915	340
Gulf Coast Subtotal	1,546	492
Central		
Mid-Continent Area Systems	2,345	348
Other	280	102
Central Subtotal	2,625	450
United States Total	**13,523**	**3,367**
Canada		
Crude Oil Pipelines:		
Manito	561	47
Rainbow	842	112
Rangeland	1,233	65
South Saskatchewan	346	62
Other	198	113
Crude Oil Pipelines Subtotal	3,180	399
NGL Pipelines:		
Co-Ed	632	58
Other	430	128
NGL Pipelines Subtotal	1,062	186
Canada Total	**4,242**	**585**
Grand Total	**17,765**	**3,952**

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

(2) Represents average volume for the entire year attributable to our interest. Volumes associated with assets employed through acquisitions or expansion capital represent total volumes (attributable to our interest) for the number of days we employed the assets divided by the number of days in the year.

(3) Pipelines operated by a third party.

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 240,000 barrels per day to 450,000 barrels per day (approximately 208,800 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 498,000 barrels per day (attributable to our interest) during 2014. Throughput volumes are measured at different points across the 520-mile pipeline and barrels can enter and leave the system moving through a short or long segment. 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 2014, we completed a project to increase capacity on the segment from Jal to Wink/Hendrick from approximately 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). We are currently constructing an extension of the Basin system, which will include looping the Wink to Midland segment of the system. This project is expected to be complete in 2015.

Mesa Pipeline System. We own a 63% undivided 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 400,000 barrels per day (approximately 252,000 barrels per day attributable to our interest). System throughput (as measured by tariff volumes) was 227,000 barrels per day (attributable to our interest) during 2014.

Sunrise Pipeline. We own and operate the Sunrise pipeline system, which extends from Midland to connecting carriers at Colorado City, Texas. Construction of this 82-mile crude oil pipeline was completed during 2014. The Sunrise pipeline was placed in service in December 2014, with an initial capacity of 250,000 barrels per day.

BridgeTex Pipeline. In November 2014, we acquired a 50% interest in BridgeTex, which is the entity that owns the BridgeTex pipeline, a newly constructed 20-inch crude oil pipeline with a capacity of 300,000 barrels per day that extends 408 miles from Colorado City in West Texas to East Houston. At Colorado City, the BridgeTex pipeline is connected to our Basin and Sunrise pipeline systems. Magellan Midstream Partners, L.P. (MMP) owns the remaining 50% interest in BridgeTex and serves as the operator of the BridgeTex pipeline. BridgeTex has entered into a long term capacity lease agreement with MMP whereby its shippers will have access to capacity on the Texas City Leg, the section of the pipeline system that runs from Houston to Texas City, and the related Houston area refinery complex.

Permian Basin Area Systems. We operate wholly owned systems of 2,838 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. During 2014, we completed construction of several projects servicing the South Spraberry area, including a new 20-inch, 62-mile crude oil pipeline with up to 200,000 barrels of takeaway capacity from the South Midland Basin to source crude oil to the Longhorn pipeline at Crane. This line will also connect to our Cactus pipeline at McCamey when the Cactus pipeline is placed into service in 2015. For 2014, combined throughput on the Permian Basin area systems totaled an average of 765,000 barrels per day.

In 2013 and 2014, we announced several new projects to increase and expand our Permian Basin infrastructure over the next few years to support expected crude oil production growth. In January 2015, we placed into service 40 miles of pipeline with 100,000 barrels per day of pipeline capacity from Monahans to Crane, Texas to supply volumes to the Longhorn pipeline as well as our Cactus pipeline when it is placed into service in 2015. Our Cactus pipeline will be a new 310-mile crude oil pipeline extending from McCamey to Gardendale, Texas and is expected to initially provide approximately 250,000 barrels per day of additional takeaway capacity from the Permian Basin. Pumping equipment will be added in 2016, which will bring the total capacity of the pipeline to approximately 330,000 barrels per day. The remainder of our projects in the area are expected to be completed in stages throughout 2015 and 2016. See Expansion Capital Projects for additional information.

South Texas/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 470 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 marine terminal facilities at Corpus Christi, as well as the Houston market via Enterprise Products Partners L.P. s (Enterprise) connection at Lyssy in Wilson County, Texas. For 2014, total average throughput on our Eagle Ford Area Systems was 227,000 barrels per day (attributable to our interest).

In 2013, we and Enterprise announced an expansion of the Eagle Ford joint venture pipeline. This project will increase the pipeline s capacity to 470,000 barrels per day by constructing a new 20-inch pipeline between Gardendale (where it will connect to our Cactus pipeline) and Three Rivers, Texas. This expansion also includes the construction of an additional 2 million barrels of operational storage capacity across the system. Additionally, in 2014 we announced the construction of a 70 mile, 20-inch pipeline from Three Rivers to Corpus Christi, and the expansion of pumping capabilities at Three Rivers. Combined, these projects will loop the entire Eagle Ford joint venture pipeline from Gardendale to Corpus Christi, and increase the total system capacity to over 600,000 barrels per day. These expansions are supported by long term production commitments. These projects are expected to be completed in 2015. See Expansion Capital Projects for additional information.

In 2014, Plains and Enterprise announced a project to construct a new condensate gathering system with approximately 55 miles of gathering and trunkline pipeline that will connect Karnes County and Live Oak County production areas to the Three Rivers, Texas terminal. Included in the gathering system will be over 500,000 barrels of operational storage at Three Rivers. This construction is expected to be completed in 2015. See Expansion Capital Projects for additional information.

Western

All American Pipeline System. We own and operate the All American pipeline system. The All American pipeline system 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.

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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 and operate 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 approximately 140 miles of gathering pipelines in the San Joaquin Valley, with an average 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. For 2014, combined throughput on Line 63 totaled an average of 48,000 barrels per day.

During 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. We have commenced a project to place this idle segment into service, which we expect to complete in 2015. In December 2014, we commenced receipts on Line 63 of crude oil from our rail terminal at Bakersfield.

Line 2000. We own and operate 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 approximately 130-mile, 20-inch trunk pipeline with a throughput capacity of approximately 130,000 barrels per day. During 2014, throughput on Line 2000 (excluding Line 63 volumes) averaged 74,000 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 the Butte pipeline. These Bakken Area systems consist of 1,025 miles of pipeline, with total average throughput for 2014 of 149,000 barrels per day.

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 680 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 2014, throughput on these systems (excluding Frontier Pipeline) in total averaged 128,000 barrels per day.

Also 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 2014, throughput on Frontier averaged 8,000 barrels per day (attributable to our interest).

White Cliffs Pipeline. We own an approximate 36% interest in the White Cliffs pipeline, a 12-inch common carrier, crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma. Rose Rock Midstream, L.P. serves as the operator of the pipeline. For 2014, throughput on White Cliffs pipeline averaged approximately 30,000 barrels per day (attributable to our interest). In August 2014, a White Cliffs pipeline expansion project that increased total system capacity from 76,000 barrels per day to 150,000 barrels per day was completed.

Cowboy Pipeline. We are currently developing the Cowboy pipeline, a 12-inch, 27-mile pipeline that will provide 65,000 barrels per day of capacity from Cheyenne, Wyoming to our rail loading facility near Carr, Colorado. The Cowboy pipeline project includes construction of a new terminal at Cheyenne with approximately 600,000 barrels of tank capacity for pipeline operation and storage. See Expansion Capital Projects for additional information.

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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. Marathon Pipeline LLC serves as the operator of the pipeline. 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 152,000 barrels per day during 2014.

In the fourth quarter of 2014, the Capline owners (including us) announced that the owner group is conducting a study to evaluate alternatives for the Capline pipeline system given the decreasing demand for South to North crude oil movements in North America. The study is expected to be completed in early 2015. Any change in the service offered by Capline would require the approval of all three owners, and there can be no assurance that the study will identify any actionable alternatives or that any alternative identified in the study will be pursued.

Pascagoula Pipeline. We own and operate the Pascagoula pipeline, a 41-mile crude oil pipeline that was placed in service in April 2014. The Pascagoula pipeline originates at our Ten Mile facility in Alabama and extends to a refinery on the Gulf Coast. Additionally, we have approximately 1.2 million barrels of storage capacity at our Ten Mile facility that supports the operational needs of this pipeline system. Throughput on the system averaged 79,000 barrels per day during 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 2,345 miles of pipeline with transportation and delivery into and out of our terminal facilities at Cushing. For 2014, combined throughput on the Mid-Continent Area systems totaled an average of 348,000 barrels per day.

In 2014, we completed construction of a 113-mile extension of our existing Oklahoma crude oil pipeline and associated gathering system to service increasing production from producing areas in Western Oklahoma and the Texas Panhandle. This new Western Oklahoma pipeline provides up to 75,000 barrels per day of new takeaway capacity from Reydon, Oklahoma to our existing Orion station in Major County, Oklahoma.

Included in the Mid-Continent Area systems is our Mississippian Lime pipeline, which was placed into service in August 2013 to service crude oil production in Northern Oklahoma and Southern Kansas and to provide crude oil transportation to our terminal facilities at Cushing. During 2014, we completed two extensions of the Mississippian Lime pipeline. Throughput on the Mississippian Lime pipeline averaged 71,000 barrels per day during 2014.

We are currently developing the Diamond pipeline, a 20-inch, 440-mile long pipeline that will provide 200,000 barrels per day of capacity from our Cushing, Oklahoma terminal to the Valero Memphis, Tennessee refinery. The Diamond pipeline project is underpinned by a long term shipper agreement with Valero and a related contract for storage and terminalling services at our Cushing terminal. We expect to complete the Diamond pipeline in 2017. Valero holds an option until January 2016 to become a partner in the Diamond pipeline and purchase a 50 percent interest.

Also under development is the Red River pipeline, which will be a 16-inch pipeline with a takeaway capacity of 150,000 barrels per day extending from Cushing, Oklahoma to Longview, Texas. The Red River pipeline is supported by long term shipper commitments and is expected to be completed in 2016. See Expansion Capital Projects for additional information regarding our Mid-Continent area pipeline projects.

Canada Pipelines

Crude Oil Pipelines

Manito. We own a 100% interest in the Manito heavy oil system. This 561-mile system is comprised of the Manito pipeline, the North Saskatchewan (North Sask) pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line that 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 339 miles of pipeline, and the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 138 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 oil from and to the Enbridge pipeline system. For 2014, 47,000 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 (i) a 480-mile, 20-inch to 24-inch mainline crude oil pipeline with a throughput capacity of approximately 220,000 barrels per day that extends from the Norman Wells Pipeline connection in Zama, Alberta to Edmonton, Alberta and has 174 miles of associated gathering pipelines and (ii) a 188-mile, 10-inch pipeline to transport diluent north from Edmonton, Alberta to our Nipisi truck terminal in Northern Alberta that has a capacity of 40,000 barrels per day. Total average throughput during 2014 on the Rainbow system was 112,000 barrels per day.

We are currently developing the Indigo pipeline, which will consist of two pipelines, a diluent line and a blend line, both approximately 80 miles in length. The diluent line will be a 12-inch pipeline that will transport diluent from our Rainbow system at Nipisi to the Peace River, Alberta area. The blend line will be a 24-inch pipeline that will deliver blended heavy crude oil from the Peace River, Alberta area to our Rainbow system. Construction is subject to regulatory approval, obtaining rights-of-way and satisfaction of other contractual provisions. The Indigo pipeline is underpinned by a long-term contract and is expected to be in service in 2017; however, the project may be delayed or terminated by the committed shipper based on certain completion dates and investment considerations, subject to full cost reimbursement to us.

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 563 miles of 3-inch to 8-inch gathering pipelines. The Rangeland system transports NGL mix, butane, condensate, light sweet crude oil and light sour crude oil 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 2014 on the Rangeland system was 65,000 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 186 miles of 4-inch to 12-inch gathering pipelines from the Rapdan area to Cantuar. The South Saskatchewan system transports heavy crude oil from gathering areas in southern Saskatchewan to Enbridge s mainline at Regina. Total average throughput during 2014 on the South Saskatchewan system was 63,000 barrels per day.

NGL Pipelines

Co-Ed NGL Pipeline System. We own and operate the Co-Ed NGL pipeline system, which consists of approximately 632 miles of 3-inch to 10-inch pipeline. This pipeline system 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 2014, throughput averaged 58,000 barrels per day.

We are currently extending and expanding our Co-Ed NGL pipeline system. The projects consist of a North Co-Ed extension and a West Co-Ed expansion, which we expect to be completed in 2016 and 2017, respectively. The North Co-Ed extension will provide approximately 20 miles of bi-directional 12-inch high vapor pressure (HVP) NGL pipeline from our existing Co-Ed pipeline to our Fort Saskatchewan facilities with takeaway capacity of up to 110,000 barrels per day. The West Co-Ed expansion will provide an 8-inch, 18 mile NGL line from our Buck Creek facility to our Co-Ed pipeline at Breton, Alberta.

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, as well as 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 agreements and processing arrangements. Revenues generated in this segment primarily include (i) fees that are generated from storage capacity agreements, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and deliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) fees from NGL fractionation and isomerization, (v) fees from natural gas and condensate processing services and (vi) fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services.

As of December 31, 2014, we owned, operated or employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 73 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 29 Bcf of owned base gas;

- 11 natural gas processing plants located throughout Canada and the Gulf Coast area of the United States;

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- a condensate processing 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;

- 26 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;

- six major marine facilities in the United States with an aggregate load capacity of 91,500 barrels per hour, including vapor recovery rates, and an aggregate unload capacity of 160,500 barrels per hour; and

- approximately 1,100 miles of active pipelines that support our facilities assets, consisting primarily of NGL and natural gas pipelines.

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, 2014, grouped by product and service type, with capacity and volume as indicated:

Crude Oil and Refined Products Storage Facilities	**Total Capacity (MMBbls)**
Cushing	20
LA Basin	8
Martinez and Richmond	5
Mobile and Ten Mile	2
Patoka	6
Philadelphia Area	4
St. James	10
Yorktown (1)	5
Other	13
	73

NGL Storage Facilities	**Total Capacity (MMBbls)**
Bumstead	4
Fort Saskatchewan	5
Sarnia Area	8
Tirzah	1
Other	5
	23

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

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Natural Gas Processing Facilities (2)	Ownership Interest	Total Gas Inlet Volume (3) (Bcf/d)	Gross Gas Processing Capacity (4) (Bcf/d)	Net Gas Processing Capacity (4) (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 (Bbls/d)
Gardendale	80,000

NGL Fractionation and Isomerization Facilities	Ownership Interest	Total Inlet Volume (3) (Bbls/d)	Gross Capacity (Bbls/d)	Net Capacity (Bbls/d)
Fort Saskatchewan	21-100%	23,622	75,000	51,300
Sarnia	62-84%	55,219	120,000	90,000
Shafter	100%	7,377	14,000	14,000
Other	82-100%	10,147	26,800	24,973
		96,365	235,800	180,273

Rail Facilities	Ownership Interest	Loading Capacity (5) (Bbls/d)	Unloading Capacity (5) (Bbls/d)
Crude Oil Rail Facilities	100%	297,000	350,000

	Ownership Interest	Number of Rack Spots	Number of Storage Spots
NGL Rail Facilities (4)	50-100%	249	1,139

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(1) Amount includes 1.1 million barrels of capacity for which we hold lease options (all 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 Cushing Terminal 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 that have increased the capacity of the Cushing Terminal to a total of 20 million barrels. During 2014, we added approximately 0.5 million barrels of such storage capacity through the construction of two 270,000 barrel tanks. Throughout 2015, we expect to add approximately 1.4 million barrels of storage through the construction of five additional 270,000 barrel tanks.

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L.A. Basin. We own four crude oil and black oil storage facilities in the Los Angeles area with a total of 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 and black oil service). Our San Francisco area terminals have 5 million barrels of combined storage capacity and 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. These 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 2 million barrels. Approximately 4 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. Of this capacity, approximately 0.5 million barrels supports our Facilities segment operations.

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. Our Ten Mile Facility is connected to our Pascagoula pipeline, which was placed into service in early 2014.

Patoka Terminal. Our Patoka Terminal has 6 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. Our terminal has access 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 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 the refiners in the Philadelphia harbor. The Philadelphia area terminals also receive products from connecting pipelines.

St. James Terminal. We have 10 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, which is being expanded to be capable of receiving heavy crude oil in 2015. See -Rail Facilities below for further discussion.

In 2014, we added approximately 1.2 million barrels of crude oil storage capacity to the St. James terminal, and we expect to add approximately 0.3 million barrels of storage capacity in 2015.

Yorktown Terminal. We have 5 million barrels of storage for crude oil and refined products at the Yorktown facility, including 1.1 million barrels of capacity for which we hold lease options (all 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.

Corpus Christi. In 2014, we announced a joint project with Enterprise Products Partners L.P. to build a Corpus Christi terminal that will be capable of loading ocean going vessels at a rate of 20,000 barrels per hour. The facility will have access to production from both the Eagle Ford and the Permian Basin. The facility is expected to be placed in service by 2017.

NGL Storage Facilities

Bumstead. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With 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 22 storage caverns with approximately 5 million barrels in useable storage capacity. 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 new NGL storage caverns each with a capacity of 350,000 barrels and will convert approximately 2.2 million barrels of existing NGL mix storage capacity to propane and condensate storage supported by the addition of approximately 2.5 million barrels of new 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 railcar 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 that 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.

The Windsor storage terminal in Windsor, Canada, is a pipeline hub and underground storage facility. The facility is served by three of our receipt/dispatch pipelines 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 initiated a brine disposal program that 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 one of our pipelines. 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, 2014, 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 20 interconnects with 12 interstate pipelines and 4 utility companies.

Natural Gas Processing Facilities

We 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. We also 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.

Condensate Processing Facility

Our Gardendale condensate processing facility in La Salle County, Texas 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 processing facility is supplied by long-term commitments from producers. During 2014, throughput averaged approximately 54,000 barrels per day. In December 2014, we received a letter from the BIS clarifying that the distillation processes employed at our Gardendale facility satisfies the conditions of the BIS to convert lease condensate into an exportable petroleum product.

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In 2015, we expect to begin construction on a third 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 2015. During 2015, we also expect to place in service a ten mile pipeline that will connect to a third party pipeline delivering NGL to Mont Belvieu.

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 NGL 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.

We recently approved a project to expand our fractionation capacity to provide producers with additional fractionation infrastructure necessary to develop the significant liquids-rich natural gas reserves in western Canada. Once completed, this expansion will increase capacity to produce a combination of spec NGL products and NGL mix by 20,000 barrels per day. This project is supported by long-term fee-for-service agreements.

Sarnia. The Sarnia Fractionator is the largest fractionation plant in Eastern Canada and receives NGL feedstock from the Enbridge 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.

We are in the process of commissioning 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.

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 297,000 barrels per day. These facilities are located in Carr, Colorado; Tampa, Colorado; Gardendale, Texas; Manitou, North Dakota; and Van Hook, North Dakota.

In 2014, we expanded 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 are currently constructing a rail terminal capable of loading 59,000 barrels per day of crude oil in Western Canada near Kerrobert, Saskatchewan. We expect to place this terminal in service in 2015.

Crude Oil Rail Unloading Facilities

We own three active crude oil rail unloading terminals that have a combined unloading capacity of approximately 350,000 barrels per day. Our terminal at St. James, Louisiana is connected to our rail unloading facility that has an unload capacity of 140,000 barrels of sweet crude oil per day. In late 2014, we approved a project to enhance our St. James rail facility with capability to receive heavy crude oil. We expect this project to be placed in service in 2015. Our Yorktown, Virginia rail facility receives unit trains and has an unload capacity of approximately 140,000 barrels per day, and our Bakersfield, California rail facility, which was placed into service in late 2014, receives unit trains and has permitted capacity to unload 70,000 barrels per day.

NGL Rail Facilities

We own 20 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 249 railcar rack spots and 1,139 railcar storage spots and we have the ability to switch our own railcars at six of these terminals.

During 2014, we approved a number of expansion projects at our Fort Saskatchewan facility, including plans to develop a 60 car per day propane rail loading facility.

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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 and natural gas;
- 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;
- 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; and
- the purchase and sale of natural gas.

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 and carrying costs for hedged inventory, 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 stable baseline 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. The tankage that is used to support our arbitrage activities positions us to capture margins in various market conditions. See Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model below for further discussion.

In addition to hedged working inventories associated with its merchant activities, as of December 31, 2014, our supply and logistics segment also owned significant volumes of crude oil and NGL classified as long-term assets and linefill or minimum inventory requirements and employed a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 13 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;
- 990 trucks and 1,100 trailers; and
- 8,100 crude oil and NGL railcars (additionally, over 1,400 new crude oil railcars on order with delivery expected in 2015).

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.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2014 (in thousands of barrels per day):

	Volumes
Crude oil lease gathering purchases	949
NGL sales	208
Supply and Logistics activities total	1,157

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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 seven years. We utilize our truck fleet and pipelines as well as leased railcars, third-party pipelines, trucks and barges to transport the crude oil to market. In addition, from time to time, 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. From time to time, we enter into various types of purchase and exchange transactions including fixed price purchase contracts, collars, financial swaps and crude oil and NGL-related futures contracts as hedging devices.

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 longer 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, rail 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. Our crude oil sales 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 seven years. We sell NGL primarily to propane and refined product retailers, petrochemical companies and refiners, and limited volumes to other marketers. A majority of our NGL contracts generally range in term from a thirty-day evergreen to one year. With the move to longer term (greater than one year) NGL supply contracts, longer term NGL sale contracts are also becoming more commonplace, usually with flexible pricing mechanisms to ensure the sale remains market-based for both buyer and seller. 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 exchanges. 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, collars, 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.

Natural Gas Purchase and Sales Activities. We also generate net revenue through the merchant storage activities of our natural gas commercial marketing group, which captures short term market opportunities by utilizing a portion of our natural gas storage capacity and engaging in related commercial marketing activities. Our natural gas merchant storage activities generate revenue through the hedged purchase and sale of natural gas net of any storage-related costs incurred. We utilize physical natural gas storage at our facilities and derivatives to hedge expected margin from these activities. Through these transactions, we seek to maintain a position that is substantially balanced between purchases of natural gas on the one hand and sales or future delivery obligations on the other hand.

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In connection with our natural gas merchant storage activities, we incur certain storage-related costs. These costs consist of fees incurred to secure third-party pipeline capacity and natural gas storage and transaction costs associated with managing injection and deliverability capacity at our facilities. Costs associated with our third-party pipeline capacity are subject to variation as the terms of these agreements typically contain certain fees which fluctuate based on actual volumes shipped in addition to monthly reservation fees.

Credit. Our merchant activities involve the purchase of crude oil, NGL and natural gas 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 and natural gas, 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 and natural gas supply and logistics activities.

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, 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 (WTI) 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 2014, West Texas Intermediate crude oil prices traded within a range of $53 to $107 per barrel. There is also volatility within the propane and butane markets as seen through the North American benchmark price located at Mont Belvieu, Texas. Specifically, propane prices have ranged from a low of approximately 43% of the WTI benchmark price for crude oil in 2013 to a high of approximately 81% of the WTI benchmark price for crude oil in 2000. Butane has seen a price range from a low of approximately 55% of the WTI benchmark price for crude oil in 2014 to a high of approximately 93% of the WTI benchmark price for crude oil in 2000.

Absent extended periods of lower crude oil or NGL prices that are below production replacement costs or higher crude oil or NGL 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 commodity 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 and NGL supply, logistics and distribution operations are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and NGL 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

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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.

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, 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 19 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Corporation and its subsidiaries accounted for approximately 17%, 15% and 16% of our revenues for the years ended December 31, 2014, 2013 and 2012, respectively. ExxonMobil Corporation and its subsidiaries accounted for approximately 15% for the year ended December 31, 2014 and approximately 13% of our revenues for each of the years ended December 31, 2013 and 2012. Phillips 66 and its subsidiaries accounted for approximately 11% of our revenues for the year ended December 31, 2013. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2014, 2013 and 2012. 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 14 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

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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 $107 million in 2014, $57 million in 2013 and $39 million in 2012. Based on currently available information, our preliminary estimate for 2015 is that we will incur approximately $75 million in capital expenditures and approximately $27 million in operational 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 voluntary, multi-year initiatives designed to prevent incidents. Costs incurred for such activities were approximately $21 million in 2014, $22 million in 2013 and $24 million in 2012, and our preliminary estimate for 2015 is that we will incur approximately $31 million of such costs.

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.

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 $32 million, $26 million and $31 million in 2014, 2013 and 2012, respectively. For 2015, 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.

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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 AER audit of PMC s operations. This order was lifted in 2014 following completion of the audit and release of the AER audit report. In 2014, the NEB gave notice that it was assessing our Canadian operations for compliance with the National Energy Board Onshore Pipeline Regulations (2013), and in respect of prior corrective actions ordered by the NEB pursuant to a 2009 audit under the predecessor Onshore Pipeline Regulations (1999). The NEB completed its assessment and issued an order in 2015 requiring PMC to file its safety critical tasks, controls and quality assurance program. The order also mandated third party audits of PMC s management system and environmental protection program, and that corrective action plans for any identified deficiencies must be filed by the end of 2015, while a third party audit of PMC s integrity management program along with corrective action plans must be filed by the end of 2016. Although we believe that all material aspects of the NEB order (costs and operational effects) have been incorporated into our budgeting and planning process, future NEB orders 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 voluntary, multi-year programs designed to prevent incidents, 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 $66 million, $90 million and $80 million in 2014, 2013 and 2012, respectively. Our preliminary estimate for 2015 is approximately $99 million.

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. For example, on December 9, 2014, new legislation was proposed at the federal level (Bill C-45 Proposed Pipeline Safety Act) which is intended to strengthen incident prevention, preparedness and response, liability and compensation to further enhance the safety of federally-regulated pipelines. It is anticipated this legislation will be passed into law in 2015. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented, though our competitors would also be affected to a similar degree.

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

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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 federal 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.

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

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conclusions as to whether GHG is contributing to warming of the Earth s atmosphere. In 2009, the 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 (a portion of these regulations were overturned by the U.S. Supreme Court in 2014). 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 or (BACT) to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they emit quantities of GHGs that trigger the requirements of these regulations. The EPA is in the process of establishing BACT for various sources of GHG emissions, but it appears likely that, for facilities such as ours, BACT will normally take the form of enhanced energy efficiency measures rather than post-combustion GHG capture requirements. We do not anticipate that the imposition of enhanced energy efficiency requirements would have an adverse material effect on the cost of our operations.

California has implemented a GHG cap-and-trade program, authorized under Assembly Bill 32 (AB32). Through 2014, California s cap-and-trade program has only applied to large industrial facilities. The California Air Resources Board has published a list of facilities that are subject to this program. At this time, the list only includes one of our facilities, the Lone Star Gas Liquids facility in Shafter, California. Beginning January 1, 2015, the AB32 regulations for the first time cover finished fuel providers and importers. California finished fuel providers (refiners and importers) will be required to purchase GHG emission credits for finished fuel sold in or imported into California. The rules implementing the AB32 program were finalized in December 2011. 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 AB32 compliance obligations after the year 2020.

The operations of our refinery and producer 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 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.

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, though our competitors would also be affected to a similar degree. 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.

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.

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. 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. Originally, the framework was intended to be implemented by 2010; however no federally mandated reduction targets for GHGs have been implemented to date. Canada has taken sectoral action on two of its largest sources of emissions electricity and vehicles. Construction of traditional coal fired generation has been banned and new vehicle emissions and fuel efficiency standards have been established through to 2025.

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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 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 17 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). The NWP is supported by strong statutory and regulatory history and was originally approved by Congress in 1977. From time to time, several environmental groups have challenged the NWP; however, to date, federal courts have upheld the validity of the NWP under the CWA. 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.

Endangered Species

New projects may require approvals and environmental analysis under federal, state and provincial laws, including the National Environmental Policy Act and the Endangered Species Act in the United States and the Species at Risk Act in Canada. The resulting costs and liabilities could materially and negatively affect the viability of such projects.

Other Regulation

Transportation Regulation

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

General Interstate Regulation. Our interstate common carrier 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.

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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.

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

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primarily the transportation of crude oil, condensates and NGL. We are required under the NSC to, among other things, 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.

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, together with more recent incidents in Lynchburg, Virginia and Fayette County, West Virginia, 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 accidents have prompted 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 (NTSB) has recommended that all tank cars used to carry crude oil be reinforced to make them more resistant to punctures if trains derail. In response to the NTSB recommendations, in July 2014, the DOT released a Notice of Proposed Rulemaking (NPRM). The NPRM proposes enhanced tank car standards, a classification and testing program for mined gases and liquids and new operational requirements for high-hazard flammable trains that included braking controls and speed restrictions. Specifically, within two years, the NPRM proposes the phase out of the use of older DOT-111 tank cars for the shipment of packing group I flammable liquids, including most Bakken crude oil, unless the tank cars are retrofitted to comply with the new tank car design requirements. We do not anticipate that any requirement to retrofit and upgrade existing rail tankers (DOT-111 or other models) would involve material cost to the partnership. The new, comprehensive rulemaking was open for public comment through September 30, 2014 and will likely take months to finalize. Similar changes have been proposed in Canada.

In December 2014, the North Dakota Industrial Commission adopted new standards to improve the safety of Bakken crude oil for transport. The new standard, Commission Order 25417, is effective April 1, 2015, and requires operators/producers to condition Bakken crude oil to certain vapor pressure limits. Under the order, all Bakken crude oil produced in North Dakota will be conditioned with no exceptions. The order requires operators/producers to separate light hydrocarbons from all Bakken crude oil to be transported and prohibits the blending of light hydrocarbons back into oil supplies prior to shipment. PAA is not directly responsible for the conditioning or stabilization of Bakken crude oil, however, under the order, it is PAA s responsibility to notify the State of North Dakota upon discovering that Bakken crude oil received at PAA s rail facility exceeds certain vapor pressure limits.

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.

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

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authority granted to the FTC with respect to crude oil purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules 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 or CFTC regulations.

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 natural gas tariffs on file with the FERC. 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. 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 third-party 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 5,300 employees at December 31, 2014. None of the employees are subject to a collective bargaining agreement, except for nine 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.

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, 2016 and 2017 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.

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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