PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 23, 2017
Table of Contents

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, 2016

or

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

Commission file number 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.
(Exact name of registrant as specified in its charter)

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

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

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

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

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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. o

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

Large Accelerated Filer 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 Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $10.8 billion on June 30, 2016, based on a closing price of $27.49 per Common Unit as reported on the New York Stock Exchange on such date.

As of February 10, 2017, there were 675,097,184 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K—2016 ANNUAL REPORT
Table of Contents

Table of Contents

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” a “forecast,” as well as similar expressions and statements 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:

- declines in the volume of crude oil and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets, whether due to declines in production from existing oil and gas reserves, reduced demand, 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;
- the effects of competition;
- market distortions caused by producer over-commitments to new or recently constructed infrastructure projects, which impacts volumes, margins, returns and overall earnings;
- 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;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event, including attacks on our electronic and computer systems;
- failure to implement or capitalize, or delays in implementing or capitalizing, on expansion projects, whether due to permitting delays, permitting withdrawals or other factors;
- 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;
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- the currency exchange rate of the Canadian dollar;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- inability to recognize current revenue attributable to deficiency payments received from customers who fail to ship or move more than minimum contracted volumes until the related credits expire or are used;
- non-utilization of our assets and facilities;
- increased costs, or lack of availability, of insurance;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- 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;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

3

Table of Contents

- risks related to the development and operation of our assets, including our ability to satisfy our contractual obligations to our customers;
- 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.

Table of Contents

PART I

Items 1 and 2. Business and Properties

General

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K and unless the context indicates otherwise, the terms “Partnership,” “Plains,” “PAA,” “we,” “us,” “our,” “ours” and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries.

We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids (“NGL”), natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics.

Organizational History

We were formed as a master limited partnership to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. From an economic perspective, we are owned 100% by our limited partners, which include Series A preferred unitholders and common unitholders. Our common units are publicly traded on the New York Stock Exchange (“NYSE”) under the ticker symbol “PAA”. Our non-economic general partner interest is held by PAA GP LLC (“PAA GP”), a Delaware limited liability company, whose sole member is Plains AAP, L.P. (“AAP”), a Delaware limited partnership. In addition to its ownership of PAA GP, as of December 31, 2016, AAP also owned an approximate 33% limited partner interest in us represented by 241.7 million of our common units.

Plains All American GP LLC (“GP LLC”), a Delaware limited liability company, is AAP’s general partner. Plains GP Holdings, L.P. (“PAGP”), a Delaware limited partnership that completed its initial public offering in October 2013, is the sole and managing member of GP LLC. Both PAGP and GP LLC have elected to be treated as a corporation for United States federal income tax purposes, and, at December 31, 2016, owned a combined 42% limited partner and economic interest in AAP. PAA GP Holdings LLC (“PAGP GP”), a Delaware limited liability company, is the general partner of PAGP.

References to the “PAGP Entities” include PAGP GP, PAGP, GP LLC, AAP and PAA GP. References to our “general partner,” as the context requires, include any or all of the PAGP Entities. References to the “Plains Entities” include us, our subsidiaries and the PAGP Entities.

Simplification Transactions

On November 15, 2016, the Plains Entities closed a series of transactions and executed several organizational and ancillary documents (the “Simplification Transactions”) intended to simplify our capital structure, better align the interests of our stakeholders and improve our overall credit profile. The Simplification Transactions included, among other things: the permanent elimination of our incentive distribution rights (“IDRs”) and the economic rights associated with our 2% general partner interest in exchange for the issuance by us to AAP of 245.5 million PAA common units (including approximately 0.8 million common units to be issued in the future) and the assumption by us of all of AAP’s outstanding debt ($642 million); the implementation of a unified governance structure pursuant to which the board of directors of our general partner was eliminated and an expanded board of directors of PAGP GP (the “PAGP

GP Board") assumed oversight responsibility over both us and PAGP; and provision for annual PAGP shareholder elections beginning in 2018 with certain directors with expiring terms in 2018, and the participation of our common unitholders in such elections through our ownership of newly issued Class C shares in PAGP, which provide us, as the sole holder, the right to vote in elections of eligible PAGP GP directors together with the holders of PAGP Class A and Class B shares. In addition, we entered into an Omnibus Agreement with AAP and PAGP to promote economic alignment between our common unitholders and PAGP's Class A shareholders by, among other measures, maintaining a one-to-one relationship between the number of outstanding PAGP Class A shares and the number of our common units indirectly owned by PAGP through AAP.

See Note 1 to our Consolidated Financial Statements for further discussion of the Simplification Transactions.

Table of Contents

Partnership Structure and Management

Our operations are conducted directly and indirectly through, and our operating assets are owned by, our subsidiaries. As the sole member of GP LLC, PAGP has responsibility for conducting our business and managing our operations; however, the PAGP GP Board has ultimate responsibility for managing the business and affairs of PAGP, AAP and us. As the sole holder of Class C shares of PAGP, we have the right to vote in elections of eligible directors, together with the holders of PAGP's Class A and Class B shares. See Item 10. "Directors and Executive Officers of Our General Partner and Corporate Governance." Our general partner does not receive a management fee or other compensation in connection with its management of our business, but it is reimbursed for substantially all direct and indirect expenses incurred on our behalf.

The two diagrams below show our organizational structure and ownership as of December 31, 2016 in both a summarized and more detailed format. The first diagram depicts our legal structure in summary format, while the second diagram depicts a more comprehensive view of such structure, including ownership and economic interests and shares and units outstanding:

Summarized Partnership Structure
(as of December 31, 2016)

(1) PAGP will hold an annual meeting for the election of eligible PAGP GP directors beginning in 2018. Through our ownership of Class C shares of PAGP, our common unitholders have the right to vote, pro rata with the holders of Class A and Class B shares of PAGP, for the election of eligible PAGP GP directors. See Item 10. "Directors and Executive Officers of our General Partner and Corporate Governance" for further information regarding governance of the Plains Entities, including changes as a result of the Simplification Transactions.

Table of Contents

Detailed Partnership Structure
(as of December 31, 2016)

Table of Contents

(1) As of December 31, 2016, the PAGP GP Board consisted of 10 members. In February 2017, the limited liability agreement of PAGP GP was amended and restated to provide for two additional directors. See Item 10. "Directors and Executive Officers of our General Partner and Corporate Governance" for further information regarding governance of the Plains Entities.

(2) Represents the number of Class A units of AAP ("AAP units") for which the outstanding Class B units of AAP (referred to herein as the "AAP Management Units") will be exchangeable, assuming the conversion of all such units at a rate of approximately 0.941 AAP units for each AAP Management Unit.

(3) Assumes conversion of all outstanding AAP Management Units into AAP units.

(4) Each Class C share represents a non-economic limited partner interest in PAGP and carries with it the right to vote, pro rata with the holders of Class A and Class B shares of PAGP, for the election of eligible PAGP GP directors.

(5) Amount does not include 792,074 common units that will become issuable to AAP that relate to AAP Management Units that are outstanding but not earned. See Note 16 to our Consolidated Financial Statements for additional discussion of the AAP Management Units.

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

(7) The Partnership holds indirect equity interests in unconsolidated entities including BridgeTex Pipeline Company, LLC ("BridgeTex"), Butte Pipe Line Company ("Butte"), Caddo Pipeline LLC ("Caddo"), Cheyenne Pipeline LLC ("Cheyenne"), Diamond Pipeline LLC ("Diamond"), Eagle Ford Pipeline LLC ("Eagle Ford Pipeline"), Eagle Ford Terminals Corpus Christi LLC ("Eagle Ford Terminals"), Frontier Aspen LLC ("Frontier"), Saddlehorn Pipeline Company, LLC ("Saddlehorn"), Settoon Towing, LLC ("Settoon Towing"), STACK Pipeline LLC ("STACK") and White Cliffs Pipeline LLC ("White Cliffs").

Business Strategy

Our 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, we endeavor 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 our transportation, terminalling, storage, processing and fractionation assets with our supply, logistics and distribution expertise. We believe successful execution of this strategy will enable us to generate sustainable earnings and cash flow. We intend to manage and grow our business by:

- optimizing our existing assets and realizing cost efficiencies through operational improvements;
- using our transportation, terminalling, storage, processing and fractionation assets in conjunction with our supply and logistics activities to capture inefficiencies, 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 our existing asset base and distribution capabilities.

Competitive Strengths

We believe that the following competitive strengths position us to successfully execute our principal business strategy:

- Many of our assets are strategically located and operationally flexible. The majority of our primary Transportation segment assets are in crude oil service, are located in well-established crude oil producing regions and other transportation corridors and are connected, directly or indirectly, with our Facilities segment assets. The majority of our 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 we have strong business relationships. In addition, our assets include pipeline, rail, barge, truck and storage assets, which provide our customers and us

Table of Contents

with significant flexibility and optionality to satisfy demand and balance markets, particularly during a dynamic period of changing product flows.

- We possess specialized crude oil and NGL market knowledge. We believe our business relationships with participants in various phases of the crude oil and NGL distribution chain, from producers to refiners, as well as our own industry expertise (including our knowledge of North American crude oil and NGL flows), provide us with an extensive understanding of the North American physical crude oil and NGL markets.
- Our 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 our Supply and Logistics segment in combination with our risk management strategies provides us with a low risk opportunity to generate a base level of margin, the amount of which may vary depending on market conditions (such as commodity price levels, differentials and certain competitive factors). In certain market scenarios, we may be able to realize incremental margins that meaningfully exceed such base levels.
- We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities. Since 1998, we have completed and integrated over 90 acquisitions with an aggregate purchase price of approximately $13.2 billion, including our February 2017 acquisition of the Alpha Crude Connector gathering system. Since 1998, we have also implemented expansion capital projects totaling approximately $11.4 billion. In addition, considering our investment grade credit rating, liquidity and capital structure, we believe we have the financial resources and strength necessary to finance future strategic expansion and acquisition opportunities. As of December 31, 2016, we had approximately $2.4 billion of liquidity available, including cash and cash equivalents and availability under our committed credit facilities, subject to continued covenant compliance.
- We have an experienced management team whose interests are aligned with those of our unitholders. Our executive management team has an average of 31 years of industry experience, and an average of 19 years with us or our predecessors and affiliates. In addition, through their ownership of common units, grants of phantom units and interests in our general partner, including interests in PAGP, AAP units and AAP Management Units, our management team has a vested interest in our continued success.

Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success is our ability to maintain a competitive cost of capital and access to the capital markets. In that regard, we intend to maintain a credit profile that we believe is consistent with investment grade credit ratings. We have targeted a general credit profile with the following attributes:

- an average long-term debt-to-total capitalization ratio of approximately 50% or less;
- 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 and further adjusted for selected items that impact comparability. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Non-GAAP Financial Measures" for a discussion of our selected items that impact comparability and our non-GAAP measures.);
- an average total debt-to-total capitalization ratio of approximately 60% or less; 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. We also incur short-term debt in connection with our 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. We do not consider the working capital borrowings associated with these activities to be part of our long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds. We also incur short-term debt 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 example, our short-term debt levels at December 31, 2016 included borrowings for $410 million of margin requirements, which is significantly elevated from historical levels primarily due to the increase in crude oil prices at the end of the year. For the years ended December 31, 2015 and 2014, we had positive cash flow associated with such margin balance activities at the end of the year of $157 million and $133 million, respectively.

Table of Contents

Typically, to maintain our targeted credit profile and achieve growth through acquisitions and expansion capital, we fund approximately 55% of the capital requirements associated with these activities with equity and cash flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile as, in certain cases, 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. As a result of the challenging environment and the impact of the gap in the timing between funding our capital program and the time the assets are placed in service and begin to generate cash flow, we expect our long-term debt-to-adjusted EBITDA to be above our target range for the near-term. We expect this leverage ratio will improve and return to our targeted levels as we execute our 2017 funding plan, complete the 2017 asset sales, and as the industry recovers and we realize EBITDA growth from our capital investments.

To improve our ability to manage through the industry downturn and to position for a recovery, we completed a number of initiatives during 2016 to maintain a solid capital structure, significant liquidity and overall financial flexibility. Such initiatives included (i) executing the Simplification Transactions in November 2016, which lowered our incremental cost of equity through the elimination of our IDRs, and in connection therewith resetting our distribution level, which resulted in an annual reduction in cash distributions of approximately $320 million, (ii) securing approximately $1.6 billion of equity capital through the sale of new Series A preferred units in January 2016, (iii) selectively utilizing our continuous offering program to raise approximately $805 million of net proceeds, (iv) selling non-core assets and entering into strategic joint ventures, which raised approximately $550 million of net cash proceeds while reducing our capital commitments, and (v) entering into a definitive agreement to sell additional assets for approximately $290 million that is expected to close in the first half of 2017, subject to regulatory approvals. See Note 6 and Note 11 to our Consolidated Financial Statements for additional discussion of these transactions.

We intend to end 2017 with a long-term debt balance at or below levels at December 31, 2016. To that end, we expect that our 2017 acquisition and expansion capital will be funded with proceeds from asset sales, equity issuances and retained cash flow.

Acquisitions

The acquisition of midstream assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objectives. Such assets and businesses include crude oil and NGL logistics assets as well as other energy assets that have characteristics and provide opportunities similar to our existing business lines and enable us to leverage our assets, knowledge and skill sets.

The following table summarizes acquisitions greater than $200 million that we have completed over the past five years.

Acquisition [(1)]	Date	Description	Approximate Purchase Price [(2)] (in millions)	
Alpha Crude Connector Gathering System	Feb-2017	Recently constructed gathering system located in the Northern Delaware Basin	$ 1,215	(3)
Spectra Energy Partners Western Canada NGL Assets	Aug-2016	Integrated system of NGL assets located in Western Canada	$ 204	(4)
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	(5)
US Development Group Crude Oil Rail Terminals	Dec-2012	Four operating crude oil rail terminals and one terminal under development	$ 503	
BP Canada Energy Company	Apr-2012		$ 1,683	(6)

		NGL assets located in Canada and the upper-Midwest United States

(1) Excludes our 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, we issued approximately 14.7 million PAA 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.

Table of Contents

(3) Purchase price subject to working capital and other adjustments. See Note 6 to our Consolidated Financial Statements for additional information regarding this acquisition.
(4) Approximate purchase price of $180 million, net of cash, inventory and other working capital acquired.
(5) Approximate purchase price of $1.075 billion, net of working capital acquired. We account for our 50% interest in BridgeTex under the equity method of accounting.
(6) 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.

Divestitures

During 2016, we initiated a program to evaluate potential sales of non-core assets and/or sales of partial interests in assets to strategic joint venture partners to optimize our asset portfolio and strengthen our balance sheet and leverage metrics. This program currently totals approximately $1.2 billion of asset sales, of which approximately $550 million closed in 2016, with the remaining $670 million either already closed or expected to close during the first half of 2017. See Note 6 to our Consolidated Financial Statements for additional discussion of our dispositions and divestitures.

Ongoing Acquisition, Divestiture and Investment Activities

Consistent with our business strategy, we are continuously engaged in the evaluation of potential acquisitions, joint ventures and capital projects. In addition, we continue to evaluate our asset portfolio to determine whether additional sales of non-core assets would further optimize our portfolio and strengthen our balance sheet. As a part of these efforts, we often engage in discussions with potential third parties regarding the possible purchase of or investment in assets and operations that are strategic and complementary to our existing operations, or the potential sale of assets that we believe might have more value to a third-party buyer. In addition, in the past we have evaluated and pursued, and intend 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 our existing business lines and enable us to leverage our assets, knowledge and skill sets. Such efforts may involve participation by us 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 we believe we are the only party or one of a limited number of parties who are in negotiations with the potential seller or other party. With respect to a potential divestiture, we may also conduct an auction process or may negotiate a transaction with one or a limited number of potential buyers. These acquisition and investment efforts often involve assets which, if acquired, constructed or sold, as applicable, could have a material effect on our financial condition and results of operations.

We typically do not announce a transaction until after we have executed a definitive agreement. However, in certain cases in order to protect our business interests or for other reasons, we 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 we have entered into a definitive agreement may be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future acquisition, divestiture or investment efforts will be successful. Although we expect the acquisitions and investments we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. See Item 1A. “Risk Factors—Risks Related to Our Business—If we do not make acquisitions or if we make acquisitions that fail to perform as anticipated, our future growth may be limited” and “—Acquisitions involve risks that may adversely affect our business.”

Expansion Capital Projects

Our extensive asset base and our relationships with customers provide us with opportunities for organic growth through the construction of additional assets that are complementary to, and expand or extend, our existing asset base. Our 2017 expansion capital plan is representative of the diversity and balance of our overall project portfolio. The following expansion capital projects are included in our 2017 capital plan as of February 2017:

Table of Contents

Basin/Region	Project	2017 Plan Amount [(1)] ($ in millions)	Description	Projected In-Service Date
Permian	Permian Basin Area Gathering System Projects	$ 120	Multiple projects to increase and expand our pipeline infrastructure in the Delaware Basin, including planned interconnects associated with the recently acquired Alpha Crude Connector gathering system	Q1 2017 - 2018
Central / Mid-Continent	Diamond Pipeline	300	50% interest in approximately 440 miles of new crude oil pipeline; 200,000 Bbls/d capacity from Cushing, OK to Valero's refinery in Memphis, TN	Q4 2017
	Cushing Terminal Expansions	30	Addition of approximately 2.1 million barrels of storage capacity and additional	Q2 2017 - Q4 2017
Canada	Fort Saskatchewan Facility Projects	90	Multi-phase project, remaining Phase I project includes conversion of service of approximately 3 million barrels of existing caverns Remaining Phase II projects include (i) adding a merox sweetening unit that will increase our ability to handle a variety of feed streams providing more flexibility and flow assurance, (ii) development of two new ethane caverns with 1.6 million barrels of capacity and a utility cavern and (iii) the addition of 2.7 million barrels of brine capacity Phase III includes a six-spot rail rack expansion for condensate service and adding butane service to four existing propane spots	Q1 2017 - 2018
Other	Other Projects	260		Q1 2017 - 2018+
Total Projected Expansion Capital Expenditures		$ 800		

(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 receipt of permits or regulatory approvals and weather.

Global Petroleum Market Overview

The health of the global petroleum market is dependent on the relative supply and demand of hydrocarbons, including crude oil and NGL. These supply and demand economics are greatly influenced by the broader global economic climate, exposing the petroleum market to the challenges and volatility associated with global economic development. For the period from 2004 through 2013, global liquids production increased 7.6 million barrels per day while global liquids consumption increased 8.4 million barrels per day. For the period from 2013 through 2015, global production growth outpaced global consumption growth by 2.5 million barrels per day resulting in a cumulative imbalance of 2.3 million barrels per day. In 2016, the market remained oversupplied, but global demand growth began to outpace global supply growth as non-OPEC production declined 0.6 million barrels per day. The table below depicts historical OPEC and non-OPEC liquids production and global liquids consumption and is derived from the EIA Short-Term Energy Outlook, January 2017 (see EIA website at www.eia.doe.gov):

	Annual Liquids Production [1]					Δ from	Δ from	Δ from
	2004	2013	2014	2015	2016	2004-2013	2013-2015	2015-2016
	(in millions of barrels per day) [2]							
Production (Supply)								
OPEC	35.0	37.6	37.5	38.7	39.6	2.6	1.1	0.9
Non-OPEC	48.4	53.4	55.9	57.5	56.8	5.0	4.1	(0.6)
Total	83.4	91.0	93.4	96.1	96.4	7.6	5.2	0.3
Total Consumption (Demand)	83.0	91.4	92.6	94.1	95.6	8.4	2.7	1.4
Global Supply / Demand Balance	0.4	(0.5)	0.8	2.0	0.9	(0.9)	2.5	(1.1)

(1) Amounts are derived from the EIA's Short-Term Energy Outlook.
(2) Amounts may not recalculate due to rounding.

This surge in liquids production without a commensurate increase in demand has led to a near-to-medium-term supply imbalance and increase in inventory, which has resulted in a reduction to benchmark petroleum prices. Producers, in turn, scaled back capital programs, which ultimately reduced supply. These outcomes are expected to lead to underinvestment in long lead time projects and additionally stimulate petroleum demand growth, which ultimately should lead to an environment where prices will recover to a level to support future production growth in the U.S.

In November 2016, OPEC indicated a desire to return to its historical strategy of managing crude oil production levels. Joined by certain non-OPEC countries such as Russia and Mexico, OPEC and non-OPEC participants have targeted to cut output by approximately 1.8 million barrels per day in the first of half of 2017. This decision drove a significant increase in crude oil prices during the fourth quarter of 2016. To the extent the production cut is executed and demand growth stays on trend, accumulated inventories should begin to decline, prices should remain firm and potentially rise, ultimately leading to increased activity levels.

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.

From 2011 through 2014, 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 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. Increased production came from 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 Williston Basin in North Dakota. As a result, North American crude oil production increased 3.7 million barrels per day, or 33% between 2011 and 2014, with the increases coming primarily from Canada, the Eagle Ford Shale, the Permian Basin and the Williston Basin. Production increases in all of these regions strained existing transportation, terminalling and downstream infrastructure. This opportunity for new crude oil infrastructure attracted significant investment in midstream oil assets, resulting in excess midstream capacity in the Permian, Eagle Ford, Williston, Mid-continent and DJ basins. The combination of the slowdown in U.S. crude oil production growth and significant commitments for new infrastructure created an environment in which margins have compressed and differentials are less than transportation cost in some cases. As production growth resumes and pipeline utilizations increase, differentials should approach transportation cost parity. The improvement is expected to occur on a regional basis subject to reductions in excess capacity.

In addition, significant shifts in the type and location of crude oil being produced in North America, relative to the types and location of crude oil being produced five years ago, have led to changes in the utilization of downstream infrastructure. From 2009 through 2015, refiners increased throughputs to take advantage of discounted domestic production, which led to lower use of imported crude oil by U.S. refineries. This decline in imports was a meaningful change in a multi-year trend where foreign imports of crude oil tripled over an approximately 23-year period from 1985 to 2007. However, in 2016, this more recent trend reversed as a result of lower 48 onshore production declines. In 2016, U.S. refinery inputs reached historically high levels fueled by price driven demand growth and exports, and U.S. petroleum consumption increased to 19.6 million barrels per day. The table below shows the overall domestic petroleum consumption projected through 2018 and is derived from the EIA Short-Term Energy Outlook, January 2017 (see EIA website at www.eia.doe.gov). This forecast shows increasing domestic production, decreasing foreign imports and steady levels of product exports.

	Actual (1)	Projected (1)	
	2016	2017	2018
	(in millions of barrels per day)		
Supply			
Domestic Crude Oil Production	8.9	9.0	9.3
Net Imports - Crude Oil	7.3	6.9	6.7
Other - (Supply Adjustment/Stock Change)	—	0.3	0.3
Crude Oil Input to Domestic Refineries	16.2	16.2	16.3
Net Product Imports / (Exports)	(2.6)	(2.5)	(2.6)

Supply from Renewable Sources	1.1	1.1	1.2
Other - (NGL Production, Refinery Processing Gain)	4.8	5.0	5.4
Total Domestic Petroleum Consumption	19.6	19.8	20.2

(1) Amounts may not recalculate due to rounding.

Table of Contents

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. Liquefied petroleum gas ("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 Form 10-K.

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 82%) of the United States NGL supply comes from gas processing plants, which separate a mixture of NGL from the dry gas (primarily methane). This 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 14% 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 and butane) 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 production points and 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

Table of Contents

granite; however, 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 created 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.

While a low price environment may stunt production growth, we believe 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;
- available processing, fractionation, storage and transportation capacity;
- petro-chemical demand driven by the build-out or new builds of Ethylene Cracker capacity (ethane demand) and Propane Dehydrogenation facilities (propane demand);
- increased export capacity for both ethane and propane;
- diluent requirements for heavy Canadian oil;
- regulatory changes in gasoline specifications affecting demand for butane;
- seasonal demand from refiners;
- seasonal weather related demand; 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 and

(iii) lower basis differentials in certain regions due to expansion and improved connectivity of natural gas transportation infrastructure.

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) increased exports of natural gas to Mexico, (iii) construction of new gas-fired power plants, (iv) sustained fuel switching from coal to natural gas among existing power plants and (v) 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.

Table of Contents

Description of Segments and Associated Assets

Our business activities are conducted through three segments—Transportation, Facilities and Supply and Logistics. We have an extensive network of 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 and descriptions below highlights our more significant assets (including certain assets under construction or development) as of December 31, 2016:

Following is a description of the activities and assets for each of our three business segments.

Table of Contents

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 entities that own the BridgeTex, Cheyenne, Eagle Ford, White Cliffs, Frontier, Saddlehorn, STACK and Butte pipeline systems, as well as Settoon Towing. We account for these investments under the equity method of accounting.

As of December 31, 2016, 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:

- 19,200 miles of active crude oil and NGL pipelines and gathering systems;
- 31 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 810 trailers (primarily in Canada); and
- 120 transport and storage barges and 60 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, 2016, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	System Miles	2016 Average Net Barrels per Day (2) (in thousands)
United States Crude Oil Pipelines		
Permian Basin		
Basin / Mesa / Sunrise	770	992
BridgeTex (3) (4)	408	108
Cactus	297	125
Permian Basin Area Systems	2,796	921
Permian Basin Subtotal	4,271	2,146
South Texas/Eagle Ford		
Eagle Ford Area Systems (4)	660	284
South Texas/Eagle Ford Subtotal	660	284
Western		
All American (5)	138	—
Line 63 / Line 2000	382	104
Other	121	84
Western Subtotal	641	188
Rocky Mountain		
Bakken Area Systems (4)	991	146
Cheyenne (4)	87	10
Saddlehorn (3) (4)	538	6
Salt Lake City Area Systems (4)	977	178
White Cliffs (3) (4)	1,054	42
Other	1,225	67
Rocky Mountain Subtotal	4,872	449

18

Table of Contents

Region / Pipeline and Gathering Systems [1]	System Miles	2016 Average Net Barrels per Day [2] (in thousands)
Gulf Coast		
Capline [3]	631	194
Pascagoula	41	143
Other	506	160
Gulf Coast Subtotal	1,178	497
Central		
Mid-Continent Area Systems [4]	2,696	325
Other	217	69
Central Subtotal	2,913	394
United States Crude Oil Pipelines Total	14,535	3,958
Canada Crude Oil Pipelines		
Manito	445	42
Rainbow	830	91
Rangeland	1,076	52
South Saskatchewan	342	60
Other	201	136
Canada Crude Oil Pipelines Total	2,894	381
Crude Oil Pipelines Total	17,429	4,339
Canada NGL Pipelines		
Co-Ed	595	61
PPTC	593	5
Other	548	118
Canada NGL Pipelines Total	1,736	184
Grand Total	19,165	4,523

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

(2) Represents average daily volumes for the entire year attributable to our interest. Average daily volumes are calculated as the total volumes (attributable to our interest) for the year divided by the number of days in the year. Volumes reflect tariff movements and thus might be included multiple times as volumes move through our integrated system.

(3) Pipelines operated by a third party.

(4) Includes total mileage and volumes (attributable to our interest) from pipelines owned by unconsolidated entities.

(5) Except for the segment of the All American Pipeline between Pentland and Emidio, the pipeline has been shut down since May 19, 2015, following the Line 901 incident.

Table of Contents

United States Pipelines

A significant portion of our U.S. pipeline assets are interconnected and are operated as a contiguous system. The following descriptions are based on geographic location.

Permian Basin

Basin Pipeline. We own an 87% undivided joint interest in and are the operator of Basin Pipeline. Basin Pipeline is a 607-mile mainline, and is the 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. Basin Pipeline 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 segment of the pipeline from Wink to Midland, Texas includes both a 24-inch pipeline and a 20-inch pipeline; together these lines have a capacity of approximately 600,000 barrels per day. The segment of the pipeline from Midland, Texas to Cushing, Oklahoma is a 22-inch to 24-inch telescoping pipeline with capacity ranging from 400,000 barrels per day to 460,000 barrels per day. The pipeline also includes approximately 6 million barrels of storage tankage, as well as a receipt facility in southern Oklahoma to aggregate South Central Oklahoma Oil Province (SCOOP) production.

Mesa Pipeline. We own a 63% undivided interest in and are the operator of Mesa Pipeline, which transports crude oil from Midland to a refinery at Big Spring, Texas, and to connecting carriers at Colorado City. Mesa Pipeline is an 80-mile mainline with capacity of up to 400,000 barrels per day (approximately 252,000 barrels per day attributable to our interest).

Sunrise Pipeline. We own and operate the Sunrise Pipeline, an 84-mile pipeline with a capacity of approximately 250,000 barrels per day that extends from Midland to connecting carriers at Colorado City.

BridgeTex Pipeline. We own a 50% interest in BridgeTex, a joint venture with a subsidiary of Magellan Midstream Partners, L.P. (“Magellan”). BridgeTex owns a 20-inch crude oil pipeline that extends from Colorado City to East Houston, Texas. At Colorado City, the BridgeTex pipeline is connected to our Basin and Sunrise pipelines. The BridgeTex pipeline has a current capacity of 300,000 barrels per day, and will be expanded to 400,000 barrels per day when pumping equipment enhancements are completed in the second quarter of 2017. BridgeTex holds a long-term capacity lease agreement with Magellan whereby its shippers have access to capacity on Magellan’s pipeline from Houston to Texas City. Magellan serves as the operator of the BridgeTex pipeline.

Cactus Pipeline. We own and operate the Cactus Pipeline, an approximate 300-mile crude oil pipeline extending from McCamey to Gardendale, Texas, where it connects to the Eagle Ford joint venture pipeline. The Cactus Pipeline has a current takeaway capacity of approximately 300,000 barrels per day from the Permian Basin, and will be expanded to approximately 390,000 barrels per day when manifold and metering enhancements are completed in 2017.

Permian Basin Area Pipelines. We operate wholly owned pipelines comprised of approximately 2,800 miles of pipe that aggregate receipts from wellhead gathering lines and bulk truck injection locations into trunk lines for transportation and delivery into the Basin Pipeline at Jal, Wink and Midland as well as to our terminal facilities in Midland. During 2016, we completed construction of several projects, including 63 miles of 20-inch crude oil pipeline from the Highway 285 Station in Reeves County to Wink, Texas in Winkler County, which increased capacity on that segment of our Pinon pipeline by approximately 200,000 barrels per day.

South Texas/Eagle Ford Area

Eagle Ford Area Pipelines. 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 Eagle Ford Pipeline, which owns a crude oil and condensate pipeline with approximately 660,000 barrels per day of capacity that extends from Gardendale to Corpus

Christi, Texas. We serve as operator of the Eagle Ford joint venture pipeline, and our joint venture partner is a subsidiary of Enterprise Products Partners, L.P. ("Enterprise").

Combined, these Eagle Ford Area Pipelines consist of 660 miles of pipe that service production in the Eagle Ford shale play of South Texas and include approximately 5 million barrels of operational storage capacity across the systems. The Eagle Ford Area Pipelines can source Eagle Ford production as well as Permian Basin production via a connection with the Cactus Pipeline at Gardendale. These pipelines serve 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 a connection with Enterprise's pipeline at Lyssy in Wilson County, Texas.

Table of Contents

Western

All American Pipeline. We own the All American Pipeline, which receives crude oil from offshore oil producers at Las Flores, California and at Gaviota, California. The pipeline 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.

In May 2015, we experienced a crude oil release from our Las Flores to Gaviota Pipeline (Line 901) in Santa Barbara County, California. The segment of the pipeline upstream of our Pentland station has been shut down since this incident. We are currently conducting a feasibility study to evaluate a replacement of the pipeline, subject to receipt of shipper commitments and regulatory approvals. See Note 17 to our Consolidated Financial Statements for additional information regarding this incident.

Line 63. We own and operate the Line 63 pipeline that transports crude oil from the San Joaquin Valley to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield, California. The pipeline is also connected to our crude oil rail terminal at Bakersfield. The Line 63 pipeline consists of an approximate 105-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 60,000 barrels per day. The Line 63 pipeline also includes approximately 30 miles of distribution pipelines in the Los Angeles Basin with a throughput capacity of approximately 20,000 barrels per day, and approximately 115 miles of gathering pipelines in the San Joaquin Valley with an average throughput capacity of approximately 35,000 barrels per day. We also have approximately 1 million barrels of storage capacity on this pipeline. In 2016, we completed the reactivation of an approximate 70-mile segment of Line 63 that had been temporarily taken out of service to allow for certain repairs and realignments to be performed.

Line 2000. We own and operate the Line 2000 crude oil pipeline that originates at our Emidio Pump Station 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.

Rocky Mountain

Bakken Area Pipelines. We own and operate several gathering systems and pipelines that service crude oil production in Eastern Montana and Western North Dakota. We also own a 22% interest in Butte, which owns a 16-inch crude oil pipeline system extending from Baker, Montana to Guernsey, Wyoming.

Cheyenne Pipeline. We own a 50% interest in Cheyenne, which owns an 87-mile, 16-inch crude oil pipeline that runs from Fort Laramie to Cheyenne, Wyoming and has a capacity of 80,000 barrels per day. Cheyenne is a joint venture with a subsidiary of Holly Energy Partners, L.P., which purchased a 50% interest in Cheyenne from us in June 2016. We serve as operator of the Cheyenne pipeline, which can be expanded through the addition of pumping capacity.

Saddlehorn Pipeline. We own a 40% interest in Saddlehorn, which owns a 62.5% undivided joint interest in a 20-inch pipeline that extends from the Niobrara and DJ Basin to Cushing, Oklahoma. Saddlehorn owns 190,000 barrels per day of the capacity in the pipeline and has approximately one million barrels of storage capacity at Platteville, Colorado. The Platteville-to-Cushing segment of the pipeline was placed in service in the third quarter of 2016, and linefill is expected to begin in the latter part of the first quarter of 2017 for the Carr-to-Platteville segment. Saddlehorn has the option to expand the capacity of the pipeline at its sole discretion and cost and would own all of the incremental capacity from any expansion. Magellan serves as operator of the Saddlehorn pipeline.

Salt Lake City Area Pipelines. We operate the Salt Lake City and Wahsatch pipelines, in which we own interests ranging between 75% and 100%, and we also own a 50% interest in Frontier, which owns the Frontier pipeline. These area pipelines 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 pipelines include approximately one million barrels of storage capacity and have a maximum throughput capacity of (i) approximately 20,000 barrels per day from Wamsutter, Wyoming to Ft. Laramie, (ii) approximately 40,000 barrels per day from Wamsutter to Wahsatch, Utah, (iii) approximately 100,000 barrels per day from Wahsatch to Salt Lake City and (iv) approximately 65,000 barrels per day from Casper to Ranch Station, Utah.

Table of Contents

White Cliffs Pipeline. We own an approximate 36% interest in White Cliffs, which owns a pipeline system consisting of two 527-mile, 12-inch, crude oil pipelines with a combined capacity of approximately 215,000 barrels per day that move crude out of the DJ Basin to the Cushing market. Rose Rock Midstream, L.P. serves as the operator of the pipeline, which originates in Platteville, Colorado and terminates in Cushing.

Gulf Coast

Capline Pipeline. Capline Pipeline, 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. Capline Pipeline has direct connection to crude oil production in the Gulf of Mexico. In addition, it is connected to an active dock capable of handling approximately 600,000-barrel tankers and is also connected to the Louisiana Offshore Oil Port and our St. James terminal. 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. The Capline owners are assessing the commercial potential to reverse the pipeline direction within the next several years, potentially enabling it to transport Canadian crude oil to the Gulf Coast.

Pascagoula Pipeline. We own and operate the Pascagoula Pipeline, a 41-mile crude oil pipeline that originates at our Ten Mile facility in Alabama and extends to a refinery on the Gulf Coast. Additionally, we have approximately 2 million barrels of storage capacity at our Ten Mile facility that supports the operational needs of the Pascagoula pipeline.

Other. During the first quarter of 2016, we sold certain of our non-core Gulf Coast pipeline assets. See Note 6 to our Consolidated Financial Statements for discussion of our divestiture activities.

Central

Mid-Continent Area Pipelines. We own and operate pipelines that source crude oil from Western and Central Oklahoma, Southwest Kansas and the Eastern Texas Panhandle. These pipelines consist of approximately 2,700 miles of pipe with transportation and delivery into and out of our terminal facilities at Cushing, Oklahoma.

We also own a 50% interest in STACK, which owns a 55-mile pipeline that transports crude oil from the Sooner Trend, Anadarko Basin, Canadian and Kingfisher Counties (STACK) play in northwestern Oklahoma to the Cushing market. STACK is a joint venture with Phillips 66 Partners, L.P., which purchased a 50% interest in STACK from us in August 2016. We serve as operator of the STACK pipeline, which has a current capacity of approximately 100,000 barrels per day and includes a terminal located at Cashion, Oklahoma with approximately 200,000 barrels of crude oil storage.

Caddo Pipeline. We own a 50% interest in Caddo, a joint venture with Delek Logistics Partners, LP (“Delek”). Caddo recently constructed and commissioned an approximate 80-mile, 12-inch crude oil pipeline with the capacity to move up to 80,000 barrels per day from our terminal in Longview, Texas to supply a refinery in the Shreveport, Louisiana area, as well as to an El Dorado, Arkansas refinery through a connection to Delek’s pipeline. We serve as operator of the Caddo pipeline, which was placed in service in December 2016.

Diamond Pipeline. We own a 50% interest in Diamond, a joint venture with Valero Energy Corporation (“Valero”). Diamond is currently constructing a 20-inch, approximately 440-mile pipeline that will provide 200,000 barrels per day of capacity from our Cushing terminal to Valero’s refinery in Memphis, Tennessee. The Diamond pipeline is underpinned by a long-term shipper agreement with Valero and a related contract for storage and terminalling services at our Cushing terminal. Construction of the Diamond pipeline is expected to be completed by late 2017. We will serve as operator of the pipeline.

Red River Pipeline (Cushing to Longview). The Red River Pipeline is a 140-mile, 16-inch crude oil pipeline with takeaway capacity of 150,000 barrels per day that extends from Cushing, Oklahoma to Longview, Texas, where it connects with various pipelines, including the Caddo pipeline. The Red River Pipeline is supported by long-term shipper commitments and was placed in service in December 2016. We serve as operator of the pipeline. In January 2017, we sold an undivided 40% interest in a segment of the Red River Pipeline to a subsidiary of Valero Energy Partners LP. The undivided interest conveyed represents 60,000 barrels per day on the segment of the pipeline extending from Cushing to Hewitt, Oklahoma near Valero’s refinery in Ardmore, Oklahoma (the “Hewitt Segment”). We retained an undivided 60% interest in the Hewitt Segment and a 100% interest in the remaining portion of the pipeline that extends from Ardmore to Longview, Texas.

Table of Contents

Canada Crude Oil Pipelines

Crude Oil Pipelines

Manito Pipeline. We own a 100% interest in the Manito heavy oil system. This 445-mile system is comprised of the Manito 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 Manito Pipeline includes 334 miles of 6-inch to 12-inch blend pipeline. The mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is a 111-mile long, 3-inch to 10-inch blend pipeline that 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.

Rainbow Pipeline. We own a 100% interest in the Rainbow Pipeline. The Rainbow Pipeline is comprised of (i) an approximate 470-mile, 20-inch to 24-inch mainline crude oil pipeline, with capacity of approximately 185,000 barrels per day of batched light sweet and heavy sour oil capacity, that extends from the Norman Wells Pipeline connection in Zama, Alberta to Edmonton, Alberta and has 173 miles of associated gathering pipelines and (ii) a 187-mile, 10-inch to 12-inch pipeline to transport diluent north from Edmonton to our Nipisi truck terminal in Northern Alberta.

Rangeland Pipeline. We own a 100% interest in the Rangeland Pipeline. Rangeland Pipeline consists of a 683-mile, 8-inch to 16-inch mainline pipeline and approximately 393 miles of 3-inch to 8-inch gathering pipelines. Rangeland Pipeline transports NGL mix, butane, condensate, light sweet crude oil and light sour crude oil either north to Edmonton or south to the U.S./Canadian border near Cutbank, Montana.

South Saskatchewan Pipeline. We own a 100% interest in the South Saskatchewan system. This pipeline consists of a 158-mile, 16-inch mainline from Cantuar to Regina, Saskatchewan and 184 miles of 4-inch to 12-inch gathering pipelines from the Rapdan area to Cantuar. South Saskatchewan Pipeline has capacity to transport approximately 68,000 barrels per day of heavy crude oil from gathering areas in southern Saskatchewan to Enbridge’s mainline at Regina.

Canada NGL Pipelines

Co-Ed NGL Pipeline. We own and operate the Co-Ed NGL pipeline, which consists of 595 miles of 3-inch to 10-inch pipeline. This pipeline gathers NGL from approximately 27 field gas processing plants located in Alberta, including all of the NGL produced at the Cochrane Straddle Plant for delivery to our NGL facilities at Fort Saskatchewan. The Co-Ed NGL pipeline system has throughput capacity of approximately 72,000 barrels per day.

PPTC Pipeline. In August 2016, we acquired a 593-mile, 6-inch pipeline extending from Empress, Alberta to the Fort Whyte Terminal in Winnipeg, Manitoba (referred to herein as the Plains Petroleum Transmission Company Pipeline, or the “PPTC” Pipeline). The addition of this pipeline increased our current NGL pipeline capacity by an additional 15,500 barrels per day. The PPTC Pipeline gives us access to seven truck terminals and three rail loading facilities across the system, allowing for increased flexibility in rail operations.

Table of Contents

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.

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 source, (iii) loading and unloading fees at our rail terminals, (iv) fees from NGL fractionation and isomerization services, (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, 2016, we owned, operated or employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 80 million barrels of crude oil and refined products storage capacity primarily at our terminalling and storage locations;
- approximately 32 million barrels of NGL storage capacity;
- approximately 97 Bcf of natural gas storage working capacity;
- approximately 31 Bcf of owned base gas;
- nine natural gas processing plants located throughout Canada and the Gulf Coast area of the United States;
- a condensate processing facility located in the Eagle Ford area of South Texas with an aggregate processing capacity of approximately 120,000 barrels per day;
- eight fractionation plants located throughout Canada and the United States with an aggregate net processing capacity of approximately 211,000 barrels per day, and an isomerization and fractionation facility in California with an aggregate processing capacity of approximately 15,000 barrels per day;
- 34 crude oil and NGL rail terminals located throughout the United States and Canada. See “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; and
- approximately 1,000 miles of active pipelines that support our facilities assets.

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, 2016, grouped by product and service type, with capacity and volume as indicated:

Crude Oil and Refined Products Storage Facilities	Total Capacity (MMBbls)
Cushing	23
LA Basin	8
Martinez and Richmond	5
Mobile and Ten Mile	5
Patoka	6
St. James	13
Yorktown (1)	5
Other (2)	15
	80

24

Table of Contents

NGL Storage Facilities	Total Capacity (MMBbls)
Bumstead	3
Empress Area	5
Fort Saskatchewan	8
Sarnia Area	10
Other	6
	32

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

Natural Gas Processing Facilities (3)	Ownership Interest	Total Gas Inlet Volume (Bcf/d)	Net Gas Processing Capacity (Bcf/d)
United States Gulf Coast Area	100%	0.1	0.3
Canada	50-100%	1.9	7.1
		2.0	7.4

Condensate Stabilization Facility	Total Capacity (Bbls/d)
Gardendale	120,000

NGL Fractionation and Isomerization Facilities	Ownership Interest	Total Spec Product (4) (Bbls/d)	Net Capacity (Bbls/d)
Empress	100%	6,300	28,300
Fort Saskatchewan	21-100%	28,300	67,800
Sarnia	62-84%	62,300	90,000
Shafter	100%	9,300	15,000
Other	82-100%	9,100	25,000
		115,300	226,100

Rail Facilities	Ownership Interest	Loading Capacity (Bbls/d)	Unloading Capacity (Bbls/d)
Crude Oil Rail Facilities	100%	380,000	350,000

	Ownership Interest	Number of Rack Spots	Number of Storage Spots
NGL Rail Facilities (5)	50-100%	335	1,515

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

(2) Amount includes approximately 2 million barrels of storage capacity associated with our crude oil rail terminal operations.

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

(4) Represents average volumes net to our share for the entire year.

(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.

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 physical 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 23 million barrels. In 2016, we added approximately 1.6 million barrels of storage and we expect to add approximately 2.1 million barrels of storage capacity during 2017.

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 refining, pipeline and marine terminal facilities 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 product by rail. We have entered into a definitive agreement to sell these non-core terminals, which we expect to close in the first half of 2017.

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 3 million barrels supports our Facilities segment operations, with the remaining storage supporting our Transportation segment assets. 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. Our Ten Mile Facility is connected to our Pascagoula Pipeline.

Patoka Terminal. Our Patoka Terminal has 6 million barrels of storage capacity and includes an 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 Pipeline as well as Canadian barrels moving south. In 2017, we expect to add approximately 0.5 million barrels of storage capacity to accommodate future pipeline connectivity.

St. James Terminal. We have 13 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. In addition, this facility includes a marine dock that is able to receive from, and load, tankers and barges and is also connected to our rail unloading facility. See “Rail Facilities” below for further discussion. In 2016, we added approximately 2.2 million barrels of storage capacity to the St. James terminal, which included connections to the rail unloading facility, marine dock and operational pipelines. In 2017, we expect to add approximately 0.4 million barrels of storage capacity.

Table of Contents

Yorktown Terminal. We have 5 million barrels of storage for crude oil and refined products at our Yorktown facility located in Virginia, including approximately 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 Terminal. We own a 50% interest in Eagle Ford Terminals, a joint venture with a subsidiary of Enterprise. Eagle Ford Terminals is currently developing a terminal in Corpus Christi, Texas that, when completed, will be capable of loading ocean going vessels at a rate of 40,000 barrels per hour. Initial storage capacity of the terminal will be approximately 1 million barrels. The facility will have access to production from both the Eagle Ford and the Permian Basin through the Eagle Ford joint venture pipeline and is expected to be placed in service in 2018.

NGL Storage Facilities

Bumstead. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With 3 million barrels of useable capacity, the facility’s primary assets include three salt-dome storage caverns, a 30-car rail track and six truck racks.

Empress Area. In August 2016, we acquired a network of seven NGL terminals (Fort Whyte, Moose Jaw, Rapid City, Stewart Valley, Dewdney, Empress and Richardson) with an aggregate useable storage capacity of 5 million barrels. Our Dewdney terminal includes two loading and unloading truck spots, with a rate of 18 trucks per day, as well as rail access to two loading racks with capacity of 20 cars per day. The Richardson terminal is connected to our recently acquired PPTC Pipeline and includes two loading truck spots with a rate of 24 trucks per day. Our Stewart Valley, Moose Jaw and Rapid City propane terminals each have one truck loading rack. The Fort Whyte terminal is equipped with a truck terminal containing two loading spots capable of loading 40 trucks per day, and a rail loading terminal with loading capacity of 13 railcars per day.

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 8 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.

In 2013, we began upgrading our Fort Saskatchewan storage capacity as part of a multi-phase expansion. The first phase of the expansion added 2.4 million barrels of new brine pond capacity and two new NGL storage caverns each with a capacity of 350,000 barrels; the first NGL cavern was completed in July 2016, and the second cavern in December 2016. We will convert approximately 3 million barrels of NGL mix storage to propane, butane and condensate storage by the end of the first quarter of 2017. The second phase of the project, which is expected to be completed in 2017, will see the development of 2.7 million barrels of new brine pond capacity and two new ethane caverns totaling 1.6 million barrels of capacity which are supported by long-term commitments from third parties.

Sarnia Area. Our Sarnia Area facilities consist of (i) our Sarnia facility, (ii) our Windsor storage terminal and (iii) our St. Clair terminal. 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, 7 multi-product truck loading racks and a network of 14 pipelines providing product delivery capabilities to our Windsor and St. Clair terminal facilities, in addition to refineries, chemical plants and other pipeline systems in the area. The Sarnia facility has approximately 5 million barrels of useable storage capacity. In 2012, we initiated a brine disposal program to facilitate the removal of excess brine via truck from our Sarnia facility. The project increased useable NGL storage capacity at the facility by 1 million barrels in 2015, and further by approximately 1 million barrels in 2016.

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 terminal assets include 16 multi-product rail tank car loading spots and a propane truck loading rack.

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 five storage caverns with useable capacity of approximately 2 million barrels and 28 multi-product rail tank car loading spots.

Table of Contents

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, 2016, we had an aggregate working gas capacity of approximately 97 Bcf in service. Our facilities have aggregate permitted 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 have 22 direct interconnects with third party interstate pipelines, industrial facilities and gas fired power plants, serving markets in the Gulf Coast, Midwest, Mid-Atlantic, Northeast, and Southeast regions of the United States and the Southeastern portion of Canada.

In January 2017, we executed a definitive agreement to sell our Bluewater natural gas storage facility located in Michigan. We expect this transaction to close in the first half of 2017, subject to customary closing conditions.

Natural Gas Processing Facilities

We own and/or operate four straddle plants and two field gas processing plants located in Western Canada. Through our August 2016 acquisition of the Empress straddle plant, we added 2.4 Bcf per day of gross NGL processing capacity with the ability to extract ethane and NGL liquids from TransCanada main lines. Cumulatively, our straddle plants have an aggregate net natural gas processing capacity of approximately 7.1 Bcf per day and a long-term liquids supply contract relating to a third-party owned straddle plant with gross processing capacity of approximately 2.5 Bcf per day. We also own and operate three natural gas processing plants located in Louisiana and Alabama with an aggregate natural gas processing capacity of approximately 0.3 Bcf per day.

NGL Fractionation and Isomerization Facilities

Empress. In August 2016, we acquired the Empress fractionation facility, which is connected to and receives liquids from our Empress straddle plant and has a fractionation capacity of approximately 28,000 barrels per day of propane, butane and condensate. The facility is capable of producing spec NGL products and connects to our recently acquired PPTC Pipeline network. See "Empress Area" under "NGL Storage Facilities" above for a description of the assets connected to the PPTC Pipeline.

Fort Saskatchewan. Our recently expanded Fort Saskatchewan fractionation facility has an inlet capacity of 85,000 barrels per day and produces spec propane, butane, condensate and a C3/C4 mix, which is sent to our Sarnia facility for further fractionation. We are in the process of adding a merox sweetening unit that will increase our ability to handle a variety of feed streams providing more flexibility and flow assurance. This final stage of the expansion is expected to be completed in late 2017 and is supported by long-term commitments from third parties. Through our 21% ownership in the Keyera Fort Saskatchewan fractionation plant, we have additional fractionation capacity, net to our share, of approximately 17,000 barrels per day.

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 net useable capacity of 90,000 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 15,000 barrels per day including NGL fractionation capacity of approximately 12,000 barrels per day.

The facility also includes an approximate 40-mile NGL pipeline system capable of delivering up to 20,000 barrels per day from California Resources Corporation's Elk Hills Gas plant to our Shafter facility, equipped with storage capacity of 30,000 barrels and 10,000 barrels per day of rail capacity.

Table of Contents

Condensate Processing Facility

Our Gardendale condensate processing facility located in La Salle County, Texas is designed to extract natural gas liquids from condensate. The facility is adjacent to our Gardendale terminal and rail facility and is connected to a third-party pipeline that delivers NGL to Mont Belvieu. The facility has a total processing capacity of 120,000 barrels per day and useable storage capacity of 160,000 barrels. Throughput at the Gardendale processing facility is supplied by long-term commitments from producers.

Rail Facilities

Crude Oil Rail Loading Facilities

We own crude oil and condensate rail loading terminals with a combined loading capacity of approximately 380,000 barrels per day. These facilities are located at or near Carr, Colorado; Tampa, Colorado; Gardendale, Texas; McCamey, Texas; Manitou, North Dakota; Van Hook, North Dakota; and Kerrobert, Saskatchewan.

Crude Oil Rail Unloading Facilities

We own three 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 per day. 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 receives unit trains and has permitted capacity to unload 70,000 barrels per day.

NGL Rail Facilities

In April 2016, we completed the Fort Saskatchewan rail terminal which consists of 20 rack spots capable of loading 60 cars per day of propane. We have initiated projects to add butane loading and condensate offloading capacity at the facility, which is expected to be in service in the third quarter of 2018.

We also own 26 operational NGL rail facilities strategically located near NGL storage, pipelines, gas production or propane distribution centers throughout the United States and Canada. Our NGL rail facilities currently have 335 railcar rack spots and 1,515 railcar storage spots, and we have the ability to switch our own railcars at six of these terminals.

Supply and Logistics Segment

Our Supply and Logistics segment operations generally consist of the following merchant-related activities:

- the purchase of U.S. and Canadian crude oil at the wellhead, the bulk purchase of crude oil at pipeline, terminal and rail facilities, and the purchase of cargos at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of NGL 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, exporters 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 generally characterize a portion of our baseline segment results generated by our Supply and Logistics segment as fee equivalent. This portion of the segment results is generated by the purchase and resale of crude oil on an index-related basis, which results in us generating a gross margin for such activities. This gross margin is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil to market as well as any operating and general and administrative expenses. The level of results 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

Table of Contents

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. During a transitional market, however, our Supply and Logistics segment may not be able to fully recover its costs on certain transactions in order to capture incremental barrels into our overall value chain. 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, 2016, 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:

- 14 million barrels of crude oil and NGL linefill in pipelines owned by us;
- 5 million barrels of crude oil and NGL linefill in pipelines owned by third parties and other long-term inventory;
- 820 trucks and 1,065 trailers; and
- 10,660 crude oil and NGL railcars.

In connection with its operations, our 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 fees 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, 2016:

	Volumes (MBbls/d)
Crude oil lease gathering purchases	894
NGL sales	259
Waterborne cargos	7
Supply and Logistics activities total	1,160

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 with remaining terms extending up to nine years. We utilize our truck fleet, railcars and pipelines as well as leased railcars, third-party pipelines, trucks and barges to transport the crude oil to market. 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. In the last few years, we have implemented an increasing number of contracts with longer terms to ensure 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 hub locations, rail facilities and dock or load port 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.

Table of Contents

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 individual refinery demand for specific grades of crude oil, area market price structures, location of customers, various modes and availability of transportation facilities to deliver crude oil and NGL to our customers.

We sell our crude oil to major integrated oil companies, independent refiners, exporters 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. We sell NGL primarily to propane and refined product retailers, petrochemical companies and refiners, and limited volumes to other marketers. The majority of our NGL contracts generally span a term of one year. For contracts greater than one year, pricing mechanisms are put in place to ensure any cost escalations are accounted for as well as annual price negotiations occur to ensure both the buyer and seller remain at market based pricing. 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.

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.

Table of Contents

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 and natural gas 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 2016, WTI crude oil prices traded within a range of approximately \$26 to \$54 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 40% of the WTI benchmark price for crude oil in 2016 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 53% of the WTI benchmark price for crude oil in 2016 to a high of approximately 99% of the WTI benchmark price for crude oil in 2016.

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 financial results 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 we project that our fee-based Transportation and Facilities segments should comprise approximately 80% or greater of our aggregate base level segment results.

Base level segment results 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 results may be adversely affected during certain transitional periods as discussed further below, 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. Beginning in the second half of 2014 to present, however, the market has experienced impacts from aggressive competition and overbuilt infrastructure in certain regions, which has caused supply and demand imbalances and price volatility. In some of the areas where we operate, there has been significantly increased competition for marginal or incremental volumes from shippers on third party pipelines who have committed to ship more production than they have and are purchasing barrels in the market for shipment on the applicable third party pipeline in satisfaction of their transportation commitments, often doing so at a loss because the loss on sale of the purchased crude oil will be less than the amount of the take-or-pay obligation on the pipeline. This type of activity has put downward pressure on volumes and margins across our three business segments. This transitioning crude oil market presents challenges to both us and the overall midstream industry, and while we believe our integrated business model and diversification of our asset base among varying regions and demand-driven and supply-driven markets gives us competitive advantages, we may see a lower level of cash flow than we would have otherwise experienced. In addition, increased competition and compressed differentials may drive lower volumes and lower unit margins in parts of our business, particularly our Supply and Logistics segment. Also, during such transitional markets, our Supply and Logistics segment may not be able to fully recover its costs on certain transactions in order to capture incremental barrels into our overall value chain creating the opportunity to provide profitability at the company level.

Table of Contents

While recent market conditions have been challenging, we believe the complementary, integrated nature of our business activities and diversification of our asset base among varying regions and demand-driven and supply-driven markets generally provides us with the opportunity to generate a base level of cash flow in a variety of market scenarios. In addition to providing the opportunity to generate a 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 fee-based cash flow from our Transportation and Facilities segments, complemented by a number of diverse, flexible and generally counter-balanced sources of cash flow within our Supply and Logistics segment is intended to provide us with the opportunity to generate a base level of cash flow and provide 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.

During certain transitional periods, such as this extended period of lower crude oil prices, the ability to generate above base line performance is challenging, and taking into account the over-capacity of midstream assets that currently exists in most crude oil producing regions, generating even baseline level performance will be challenging. See "Global Petroleum Market Overview " above for additional discussion regarding market conditions.

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.

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 may occur. 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 18%, 17% and 17% of our revenues for the years ended December 31, 2016, 2015 and 2014, respectively. ExxonMobil Corporation and its subsidiaries accounted for 14%, 13% and 15% of our revenues for the years ended December 31, 2016, 2015 and 2014, respectively. Phillips 66 Company and its subsidiaries accounted for 11% of our revenues for the year ended December 31, 2016. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2016. 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 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, together with the fact that many of the producing basins in the United States and Canada currently have excess take-away capacity (whether by pipeline or rail), generally make it less likely that new competing pipeline systems comparable in size and scope to our larger pipeline systems (and excluding those already publicly announced to be under development or construction) will limit the number of new pipeline projects over the next few years. However, there are currently third-party owned pipelines or owners with joint venture pipelines with excess capacity in the vicinity of our operations that expose us to significant competition based on the relatively low cost of moving an incremental barrel of crude oil or NGL. In the current environment, such competition for marginal or incremental volumes has been exacerbated in some areas by shippers on third party pipelines who have committed to ship more production than they own or have secured under contract and are purchasing barrels in the market and shipping them on the applicable third party pipeline in satisfaction of their transportation commitment. This type of activity reduces the pool of incremental barrels that would otherwise be available for transport on our pipelines. 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 and terminalling companies, other NGL processing and fractionation companies, the major integrated oil companies and their marketing affiliates, independent gatherers, private equity backed entities, 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.

Table of Contents

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 fines and penalties, expose us to civil and criminal claims, and cause us to incur significant costs and expenses. In all material respects, we believe that we are in substantial compliance with the various laws, rules and regulations that apply to our assets, operations and business activities; however, we can provide no assurances in that regard. See Item 1A. "Risk Factors—Risks Related to Our Business—Our operations are also subject to laws and regulations relating to protection of the environment and wildlife, operational safety, climate change and related matters that may expose us to significant costs and liabilities." 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. We can provide no assurance that the increased costs associated with any new or proposed laws, rules or regulations will not be material. We may at any time also be required to apply significant resources in responding to governmental requests for information and/or enforcement actions.

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. Environmental and safety laws and regulations are subject to changes that may result in more stringent requirements, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and any claims made by third parties. The following is a summary of some of the environmental, health and safety laws and regulations to which our operations are subject.

Pipeline Safety/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 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 $89 million in 2016, $107 million in 2015 and $107 million in 2014. Based on currently available information, our preliminary estimate for 2017 is that we will incur approximately $95 million in capital expenditures and approximately

Table of Contents

$35 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. 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 $48 million in 2016, $33 million in 2015 and $21 million in 2014, and our preliminary estimate for 2017 is that we will incur approximately $50 million of such costs.

In 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "2011 Act") became effective. Under the 2011 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 2011 Act reauthorized 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 2011 Act have the potential to cause owners and operators of pipeline facilities to incur significant capital expenditures and/or operating costs.

The Securing America's Future Energy: Protecting Infrastructure of Pipelines and Enhancing Safety Act ("SAFE PIPES Act") was signed into law on June 22, 2016. This bill imposes a number of requirements on the industry and PHMSA, but the key provisions include: (i) reauthorization of PHMSA through fiscal year 2019, (ii) requirements for reports to Congress on the status of rulemaking efforts and certain specific information gathering efforts, (iii) a requirement that PHMSA initiate new rulemaking for underground natural gas storage facilities, (iv) a requirement to convene a work group on the development of a voluntary information sharing program; and (v) the granting of authority to the DOT to issue industry-wide emergency orders under certain circumstances.

The pending rule-making efforts that are required by the SAFE PIPES Act, and that could materially affect the operation of pipeline operators, include: (i) expansion of integrity management programs beyond high-consequence areas, (ii) additional regulation of pipeline leak detection systems and (iii) the use of shut-off valves and excess flow valves in certain applications. We will monitor the rule-making resulting from the SAFE PIPES Act, as well as the reports PHMSA is obligated to provide to Congress to better understand the potential impact to our operations. At this time we cannot predict the full impact to our operations or the potential additional cost of compliance.

In October 2015, PHMSA published a Notice of Proposed Rulemaking ("NPRM") in the Federal Register proposing to make changes to the hazardous liquid pipeline safety regulations. PHMSA is proposing to make the following changes to the regulations:

- Extend reporting requirements to all hazardous liquid gravity and gathering lines;
- Require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events, and periodic inline integrity assessments of pipelines that are located outside of high consequence areas of at least once every ten years;
- Use of leak detection systems on hazardous liquid pipelines in all locations;
- Modify the provisions for making pipeline repairs;
- Require that all pipelines subject to the integrity management requirements be capable of accommodating inline inspection tools within 20 years; and
- Clarifications to improve certainty and compliance to certain existing regulations.

PHMSA announced the regulatory text of the final rule on January 13, 2017; however, the complete text was not published in the Federal Register prior to the regulatory freeze put in place by the incoming administration on January 24, 2017. The regulatory freeze was instituted to allow the incoming administration the opportunity to review all pending rules. The rule will go into effect six months after publication in the Federal Register. We do not currently believe this rule will have a significant adverse financial impact on our operations.

If approved by PHMSA, states may assume responsibility for enforcing federal interstate pipeline regulations as agents for PHMSA and conduct inspections of interstate pipelines. In practice, states vary in their authority and capacity to address pipeline safety.

Table of Contents

The California Governor signed into law the following three bills on October 8, 2015 related to pipeline safety:

- The Oil Spill Response Bill allows volunteer cleanup crews to be paid as contractors, requires oil skimmers to be placed along the coastline at all times, and prohibits the use of dispersants until the EPA issues rules on dispersant safety.
- The Pipeline Safety: Inspections Bill (SB 295) mandates annual pipeline inspections commencing January 1, 2017, with the State Fire Marshal responsible for annually inspecting all intrastate pipelines and operators of intrastate pipelines under the jurisdiction of the State Fire Marshal.
- The Oil Spill Response: Environmentally and Ecologically Sensitive Areas Bill (AB 864) requires automatic shut-offs for pipelines located in environmentally sensitive areas.

The SB 295 rulemaking efforts were completed in 2016 and the annual pipeline inspection requirements commence in 2017. Efforts to draft and implement regulations to adopt the provisions of AB 864 continue and are expected to be finalized by July 2017. We cannot currently predict the impact and costs of these new laws, and any associated regulations, on our operations.

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, our costs associated with this program were approximately $29 million, $33 million and $32 million in 2016, 2015 and 2014, respectively. For 2017, we have budgeted approximately $40 million in connection with continued API 653 compliance activities and similar new EPA regulations for tanks not regulated by the DOT. Certain storage tanks may be taken out of service if we believe the cost of compliance will exceed the value of the storage tanks or replacement tankage may be constructed.

Canada

In Canada, the NEB and provincial agencies such as the Alberta Energy Regulator (“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.

The Pipeline Safety Act, SC 2015, c. 21 (the “Pipeline Safety Act” or the “Act”) came into force in June 2016, amending the National Energy Board Act and the Canada Oil and Gas Operations Act in order to strengthen the safety and security of pipelines regulated under those acts. It reinforces the “polluter pays” principle, such that operators of pipelines are liable for costs and damages for all unintended or uncontrolled releases of oil, gas, or other substances. The Act introduces absolute liability for costs and damages up to $1 billion from an uncontrolled release of oil, gas or other commodity from a major pipeline (i.e. those with capacity over 250,000 barrels per day). Additionally, operators will be required to maintain the financial resources necessary to meet the applicable absolute liability obligations imposed under the Act. Finally, the Act imposes requirements with respect to abandoned pipelines, including an obligation to maintain adequate funds to pay for abandonment costs. The total transport capacity of our pipelines regulated by the NEB exceeds 250,000 barrels per day so financial instruments in the form of lines of credit and insurance verification were filed with the NEB. The Pipeline Safety Act also amended the pipeline damage prevention provisions of the National Energy Board Act and regulations for pipeline damage prevention came in effect June 2016. Potential operational requirements and costs may be incurred around depth of cover information and mitigation with landowners, crossings and encroachments, turnaround timelines for responding to dig requests near pipelines and land use monitoring for adjacent lands to the pipeline right-of-way. The cost impact of the Pipeline Safety Act on us is not expected to be material.

In addition to required activities, our Canadian 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 $56 million, $66 million and $66 million in 2016, 2015 and 2014, respectively. Our preliminary estimate for 2017 is approximately $75 million.

Table of Contents

We cannot predict the potential costs associated with additional, future regulation. Significant additional expenses could be incurred, and additional operational requirements and constraints could be imposed, if new or more stringently interpreted pipeline safety requirements are implemented.

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.

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.

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 waste under RCRA may be revisited and our wastes subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from RCRA regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary.

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. In March 2016, the EPA proposed revisions to the Risk Management Plan ("RMP") rules, including requirements for the use of third

Table of Contents

party compliance audits, root cause analyses for facilities that experience releases, process hazard analyses and enhanced information-sharing provisions. OSHA has announced that it is considering similar revisions to the PSM rule, but, to date, has not issued an NPRM.

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 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 may 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. In October 2015, the EPA promulgated a revised national ambient air standard for ozone. While full implementation of the standard may take a number of years, the revised standard could make air permits for sources of volatile organic compounds (such as crude oil tank farms) more difficult to obtain in some areas. In addition, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and control requirements.

Our Canadian operations are subject to federal and provincial air emission regulations. 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 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.

As a result of the changing requirements in both Canada and the United States such as those mentioned above, 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. 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

The EPA has adopted rules for the reporting of carbon dioxide, methane and other greenhouse gases ("GHG") from certain sources. 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 our facilities and activities.

The EPA has also promulgated regulations establishing Title V and Prevention of Significant Deterioration permitting requirements for certain large sources of GHGs. Fewer than ten of our existing facilities are potential major sources of GHG subject to these permitting requirements. We may be required to install "best available control technology" ("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. 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 will have a material adverse effect on the cost of our operations.

In June 2016, the EPA finalized regulations affecting new, modified and reconstructed sources of air emissions in the oil and natural gas sector that require significant reductions in fugitive methane emissions from certain upstream and midstream oil and gas facilities. These new rules also require operators to implement fugitive emission leak detection and repair requirements for compressor stations. We do not expect the cost of complying with these rules to have a 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 because it is a significant combustion source. As a result, compliance instruments for GHG emissions have been purchased since 2013.

On January 1, 2015, the AB32 regulations for the first time covered finished fuel providers and importers. California finished fuels providers (refiners and importers) were required to purchase GHG emission credits for finished fuel sold in or imported into California. Plains Marketing was included in this portion of the regulation due to propane imports and completed its first year of compliance in 2016. 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. The California Air Resources Board is currently developing a scoping plan for AB32 compliance obligations after the year 2020. We will be reporting associated GHG emissions for finished fuels imported and exported across California borders and will be subject to the cap and trade program in 2016.

Executive Order B-30-15 was signed by California’s Governor in mid-year 2015. This Executive Order requires a 40% reduction in GHG emissions from the 1990 baseline level by 2030. The current 2020 goals for GHG emissions reductions are at 15% below the 1990 baseline level. Compliance with this reduction requirement may necessitate the lowering of the threshold for industrial facilities required to participate in the GHG cap and trade program. This may increase the number of PAA facilities subject to this program.

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.

In December 2015, the Paris Agreement was signed at the 21st annual Conference of Parties to the United Nations Framework Convention on Climate Change (“UNFCCC”). The Paris Agreement, which came into effect in November 2016, requires signatory parties to develop and implement carbon emission reduction policies with a goal of limiting the rise in average global temperatures to 2°C or less. This Agreement is likely to become a significant driver for future potential GHG reduction programs in the United States and Canada.

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.

Canada

Federal Regulations. Along with 194 other countries, Canada is a signatory to the UNFCCC “Durban Platform” committing it to develop a legally binding agreement to reduce GHG emissions by 2020. Since 2004, large emitters of GHG were required to report their emissions under the Canadian Greenhouse Gas Emissions Reporting Program. Three PMC facilities meet the current 50kt/y reporting threshold.

Table of Contents

The federal Department of Environment and Climate Change is proposing to lower the reporting threshold for all facilities from 50kt/y to 10 kt/y. The enactment of this proposal would result in more PMC facilities being required to prepare annual reports of their emissions. The associated costs with this requirement would not be considered material.

In October 2016, the Government of Canada proposed a pan-Canadian approach to pricing carbon pollution requiring all Canadian provinces and territories to have carbon pricing in place by 2018. The provinces and territories will have flexibility in deciding how they implement carbon pricing either by placing a direct price on carbon pollution or adopting a cap-and-trade system. The price on carbon pollution will start at $10/tonne in 2018 and rise by $10 a year to reach $50/tonne in 2022.

Provincial Regulations

Ontario. In February 2015, the Ontario Ministry of Environment and Climate Change issued a discussion paper that identified carbon pricing as a critical action necessary to reduce emissions of greenhouse gases. In April 2015, the Ontario government announced it would be implementing a GHG cap and trade program, which would be implemented through the Western Climate Initiative (WCI), which includes Quebec and California. Mandatory participants for the program will be responsible for their emissions starting on January 1, 2017.

PMC's facility at Sarnia is considered to be a mandatory participant in the program (threshold >25,000 tonnes GHG emissions). At this early stage of the program, it is not possible to predict any material increases in compliance costs or additional operating restrictions.

Alberta. The Alberta Climate Change and Emissions Management Act provides a framework for managing GHG emissions by reducing specified gas emissions to 50% of 1990 levels by December 31, 2020. The accompanying Specified Gas Emitters Regulation imposes GHG emissions limits on large emitters and requires reductions in GHG emissions intensity. Since the regulation came into effect, PMC has two facilities (Fort Saskatchewan Storage and Fractionation Facility and Empress VI) which currently do not meet the reduction obligation. As such, PMC has been required to submit compliance payments to the Climate Change Emissions Management Fund (the "CCEMC"). CCEMC will increase from $30 per tonne (from $20 in 2016) of CO_2 over a facility's budget in 2017, which will increase our operating costs at these two facilities.

On May 24, 2016, the Government of Alberta introduced Bill 20: the Climate Leadership Implementation Act, which implements a carbon levy on Alberta businesses previously announced under the Plan. Subject to certain exemptions, the Act applies a carbon levy to all sales and imports of fuel. PMC has registered and received specific exemptions for its Alberta facilities until January 1, 2023. The combined effect of these Alberta climate change enactments is not expected to be material.

Saskatchewan. The Management and Reduction of Greenhouse Gases Act received royal assent on May 20, 2010 and set 20% GHG emission reduction targets below 2006 levels by 2020, but no regulations to implement the targets have been passed by the provincial government to date. The provincial government continues discussions with the federal government on implementation.

Water

The U.S. 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/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 U.S. 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. 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.

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 over 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 program is supported by strong statutory and regulatory history and was originally approved by Congress in 1977. From time to time, environmental groups have challenged the NWP program; however, to date, federal courts have upheld the validity of NWP program under the CWA. We cannot predict whether future lawsuits will be filed to contest the validity of NWP; however, in the event that a court wholly or partially strikes down the NWP program, which we believe to be unlikely, we could face significant delays and financial costs when seeking project approvals from the Corps.

In May 2015, the EPA published a final rule that attempted to clarify federal jurisdiction under the CWA over waters of the United States, but a number of legal challenges to this rule are pending, and implementation of the rule has been stayed nationwide. To the extent the rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The Corps completed their five-year review and update of the NWPs in 2016, publishing the final version of the revised NWPs in the Federal Register on January 6, 2017. The revised NWPs will be effective on March 19, 2017. Changes to NWP 12, which applies to linear projects such as pipelines, could impact both the time to obtain project authorization under NWP 12 and the cost to comply with the revised conditions.

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 associated with lengthy regulatory review and approval requirements 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 operating costs reflect the recurring costs resulting from compliance with these regulations. The following is a summary of the types of transportation regulation that may impact our operations.

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

State Regulation in the United States. 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.

U.S. 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, 2016, the annual index adjustment for the five year period ending

June 30, 2021 will equal the producer price index for finished goods for the applicable year plus an adjustment factor of 1.23%. 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.

Table of Contents

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.

Pipeline Rate Regulation in the United States. The FERC historically 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. FERC issued an Advance Notice of Proposed Rulemaking on October 20, 2016 that addressed issues related to FERC’s indexing methodology and liquids pipeline reporting practices. If implemented, the proposals in this rulemaking could affect the profitability of certain liquids pipelines. On December 15, 2016, FERC issued a Notice of Inquiry regarding certain matters related to FERC’s income tax allowance policy. Parties are currently submitting comments in response to this notice, and FERC could, after review of those comments, decide to propose changes to its current policy.

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.

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 and (vi) operation and equipment safety. 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. O