PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 27, 2019
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, 2018
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 every Interactive Data File required to be submitted 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 such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer o

Non-accelerated filer o	Smaller reporting company o
	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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 $10.4 billion on June 29, 2018, based on a closing price of $23.64 per Common Unit as reported on the New York Stock Exchange on such date. As of February 12, 2019, there were 726,579,550 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement to be filed pursuant to Regulation 14A pertaining to the 2019 Annual Meeting of Unitholders are incorporated by reference into Part III hereof. The registrant intends to file such Proxy Statement no later than 120 days after the end of the fiscal year covered by this Form 10-K.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K—2018 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 actual or expected 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, including the effects of capacity overbuild in areas where we operate;
- market distortions caused by over-commitments to infrastructure projects, which impacts volumes, margins, returns and overall earnings;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, NGL and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event, including cyber or other 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;
- 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;
- 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 availability of, and our ability to consummate, acquisition or combination opportunities;
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from 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 effectiveness of our risk management activities;

Table of Contents

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- risks related to the development and operation of our assets, including our ability to satisfy our contractual obligations to our customers;
- 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, 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 primarily for crude oil, natural gas liquids (“NGL”) and natural gas. 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 common unitholders and Series A and Series B preferred unitholders. Our common units are publicly traded on the New York Stock Exchange under the ticker symbol “PAA.” Our Series A preferred units are convertible into common units on a one-for-one basis by the holders of such units or by us in certain circumstances. Our common units and Series A preferred units are collectively referred to as “Common Unit Equivalents.” Our Series B preferred units are not convertible into common units and are not included in Common Unit Equivalents.

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, 2018, AAP also owned a limited partner interest in us through its ownership of approximately 280.5 million of our common units (approximately 35% of our total outstanding Common Unit Equivalents).

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, and, at December 31, 2018, owned, directly and indirectly, an approximate 57% limited partner interest in AAP. Both PAGP and GP LLC have elected to be treated as corporations for United States federal income tax purposes. 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.

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 board of directors of PAGP GP (the “PAGP GP Board”) has ultimate responsibility for managing the business and affairs of PAGP, AAP and us. 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, 2018 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, 2018)

(1) Through a “pass-through” voting right as a result of our ownership of Class C shares of PAGP, our common unitholders have the effective 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.

(2) Represents percentage ownership of Common Unit Equivalents.

Table of Contents

Detailed Partnership Structure
(as of December 31, 2018)

Table of Contents

(1) 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.

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

(3) Each Class C share represents a non-economic limited partner interest in PAGP. Through a "pass-through" voting right as a result of our ownership of Class C shares of PAGP, our common unitholders have the effective 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.

(4) Amount does not include (i) 48,606 common units that will become issuable to AAP that relate to AAP Management Units that were outstanding but not earned as of December 31, 2018 and (ii) 183,819 common units that were issued to AAP in January 2019 in respect of AAP Management units that became earned effective December 31, 2018.

(5) Represents percentage ownership of Common Unit Equivalents. Series B preferred units are not convertible into common units and are not included in Common Unit Equivalents.

(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 Advantage Pipeline, L.L.C. ("Advantage"), BridgeTex Pipeline Company, LLC ("BridgeTex"), Cactus II Pipeline LLC ("Cactus II"), 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"), Midway Pipeline LLC ("Midway Pipeline"), Saddlehorn Pipeline Company, LLC ("Saddlehorn"), Settoon Towing, LLC ("Settoon Towing"), STACK Pipeline LLC ("STACK") and White Cliffs Pipeline, L.L.C. ("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:

- running a safe, reliable, environmentally and socially responsible operation, which includes driving operational excellence, cost savings, asset optimization and improved efficiencies throughout the organization;
- 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;
- using our transportation, terminalling, storage, processing and fractionation assets in conjunction with our supply and logistics activities to provide flexibility for our customers, capture market opportunities, address physical market imbalances, mitigate inherent risks and increase margin; 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 (with our largest asset presence in the Permian Basin) 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 with significant flexibility and optionality to satisfy demand and balance markets, particularly during a dynamic period of changing product flows and recent developments with respect to rising crude oil exports.

Table of Contents

- 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 positive 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 incremental margin, the amount of which may vary depending on market conditions (such as differentials and certain competitive factors).
- We have the strategic and technical skills and the financial flexibility to continue to pursue acquisition and expansion opportunities, whether on our own or through joint ventures. Since 1998, we have completed and integrated over 90 acquisitions with an aggregate purchase price of approximately $13.2 billion. Since 1998, we have also implemented expansion capital projects totaling over $14.4 billion. In addition, considering our investment grade credit ratings at two of three agencies, liquidity and capital structure, we believe we have the financial resources and strength necessary to finance future strategic expansion, joint venture and acquisition opportunities. As of December 31, 2018, we had approximately $2.9 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 30+ years of industry experience, and an average of 16 years with us or our predecessors and affiliates. In addition, through their ownership of common units and grants of phantom units and interests in our general partner, 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 significant financial flexibility, 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 target a 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, which has been our historical target range and is currently under internal review ("Adjusted EBITDA" is earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization and gains and losses on significant asset sales by unconsolidated entities), gains and losses on asset sales and asset impairments, and gains on sales of investments in unconsolidated entities, 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, but do not include certain components of our capital structure such as short-term debt, preferred units and operating leases that may be considered by rating agencies in assigning their ratings. At December 31, 2018, our publicly-traded senior notes comprised approximately 98% of our reported long-term debt. Additionally, we also routinely incur short-term debt primarily in connection with our supply and logistics activities that involve the simultaneous purchase and forward sale of crude oil and NGL. The crude oil and NGL purchased in these transactions are hedged. 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 above certain baseline levels. Similar to our working capital borrowings, these borrowings are self-liquidating. We do not consider the working capital borrowings or margin requirements associated with these activities to be part of our long-term capital structure.

Table of Contents

To maintain our targeted credit profile and achieve growth through acquisitions and expansion capital, we have historically targeted to fund approximately 55% of the capital requirements associated with these activities with equity, cash flow in excess of distributions or proceeds from asset sales. However, in connection with our leverage reduction plan, as discussed below, and in recognition of challenging financial markets, we have retained a larger amount of cash flow in excess of distributions, sold a meaningful amount of assets and refrained from accessing the equity capital markets. Additionally, 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.

Leverage Reduction Plan

In August 2017, we announced that we were implementing an action plan to strengthen our balance sheet, reduce leverage, enhance our distribution coverage, minimize new issuances of common equity and position the Partnership for future distribution growth. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Summary" for a summary of this action plan and the status of our efforts to implement such plan.

Acquisitions

The acquisition of midstream assets and businesses that are strategic and complementary to our existing operations constitutes an important 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	Date	Description	Approximate Purchase Price [1] (in millions)	
Alpha Crude Connector Gathering System	Feb-2017	Recently constructed gathering system located in the Northern Delaware Basin	$ 1,215	
Spectra Energy Partners Western Canada NGL Assets	Aug-2016	Integrated system of NGL assets located in Western Canada	$ 204	(2)
50% Interest in BridgeTex Pipeline Company, LLC ("BridgeTex")	Nov-2014	BridgeTex owns a crude oil pipeline that extends from Colorado City, Texas to East Houston	$ 1,088	(3)

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

(2) Approximate purchase price of $180 million, net of cash, inventory and other working capital acquired.

(3) Approximate purchase price of $1.075 billion, net of working capital acquired. In 2018, we sold a 30% interest in BridgeTex. See Note 9 to our Consolidated Financial Statements for more information. We account for our 20% interest in BridgeTex under the equity method of accounting.

Divestitures

In 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. Through December 31, 2018, we have completed asset sales totaling approximately $3.0 billion, of which approximately $0.6 billion closed in 2016 (net of amounts paid for the remaining interest in a pipeline that was subsequently sold), approximately $1.1 billion closed in 2017 and approximately $1.3 billion closed in 2018. See Note 7 to our Consolidated Financial Statements for additional discussion of our dispositions and divestitures.

Table of Contents

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. As a part of these efforts, we often engage in discussions with potential sellers or other parties regarding the possible purchase of or investment in assets and operations that are strategic and complementary to our existing operations. In response to changing U.S. production profiles and increased competition for new build assets, over the last several years, we have increased our joint venture related activities in an effort to fully meet the current and future needs of our customers while also rationalizing assets and enhancing our investment returns. The vast majority of our joint ventures are accounted for as investments in unconsolidated subsidiaries. In addition, we have in the past 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 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. These acquisition and investment efforts often involve assets which, if acquired or constructed, could have a material effect on our financial condition and results of operations.

From time to time, we may also (i) sell assets that we regard as non-core or that we believe might be a better fit with the business or assets of a third-party buyer or (ii) sell partial interests in assets to strategic joint venture partners, in each case to optimize our asset portfolio and strengthen our balance sheet and leverage metrics. 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.

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 or investment efforts will be successful, or that our strategic asset divestitures will be completed. 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 make acquisitions that fail to perform as anticipated, our future growth may be limited” and “—Acquisitions and joint ventures 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. The following expansion capital projects are included in our 2019 capital plan as of February 2019:

Project	Description	Projected In-Service Date	2019 Plan Amount [1] ($ in millions)
Permian Basin Takeaway Pipeline Projects	Primarily includes contributions for our (i) 65% interest in the Cactus II joint venture pipeline and (ii) 20% interest in the Wink to Webster joint venture pipeline	2H 2019 - 2021	$ 630
			285

Complementary Permian Basin Projects	Multiple projects to support the Permian Basin takeaway pipeline projects, and to expand/extend our gathering and intra-basin pipelines as well as terminalling and storage facilities at market hub locations	1H 2019 - 2020+	
Other Projects		1H 2019 - 2020+	185
Total Projected Expansion Capital Expenditures			$ 1,100

(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. Amounts reflect our expectation that certain projects will be owned in a joint venture structure with a proportionate share of the project cost dispersed among the partners.

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 NGLs. 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. The table below depicts historical global liquids production and consumption and is derived from the U.S. Energy Information Administration ("EIA") Short-Term Energy Outlook, February 2019 (see EIA website at www.eia.doe.gov):

	2013	2014	2015	2016	2017	2018	Δ from 2013 - 2014	Δ from 2014 - 2015	Δ from 2015 - 2016	Δ from 2016 - 2017	Δ from 2017 - 2018
	million barrels per day [2]										
Production (Supply)											
U.S.	12.4	14.1	15.1	14.8	15.7	17.9	1.8	1.0	(0.3)	0.8	2.2
OPEC	35.1	35.1	36.4	37.4	37.3	37.3	—	1.2	1.0	(0.1)	—
Other World	44.1	44.9	45.5	45.1	45.1	45.3	0.8	0.6	(0.3)	(0.1)	0.3
Total	91.6	94.2	97.0	97.4	98.0	100.5	2.5	2.8	0.4	0.6	2.5
Total Consumption (Demand)	92.3	93.9	95.9	96.9	98.6	100.0	1.6	2.0	1.0	1.7	1.5
Global Supply / Demand Balance	(0.6)	0.3	1.1	0.5	(0.5)	0.5	0.9	0.8	(0.6)	(1.1)	1.0

(1) Data reflects actuals through October 2018.
(2) Amounts may not recalculate due to rounding.

In 2018, OPEC continued to manage crude oil production levels. Joined by certain non-OPEC countries such as Russia, OPEC and non-OPEC producers agreed to cut production by 1.2 million barrels per day from October 2018 levels, beginning January 2019. In addition, in December of 2018, the province of Alberta mandated crude oil production cuts by imposing production limits designed to remove approximately 325,000 barrels per day from the market; such production limits were relaxed in February 2019 to allow an additional 75,000 barrels per day of production.

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 drive 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.

Table of Contents

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 2015, 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 from U.S. oil-producing areas such as the Rockies, the Permian Basin in West Texas, the Mid-Continent region, the Eagle Ford Shale in South Texas, and the Williston Basin in North Dakota caused U.S. lower 48 onshore crude oil production to increase by 3.7 million barrels per day, or 99%, between 2011 and 2015. In 2015, U.S. Lower 48 onshore crude oil production peaked at 7.6 million barrels per day in March. By that point crude oil prices had begun to decline, causing many North American operators to significantly scale back their capital programs, resulting in production declines. By February 2016 West Texas Intermediate crude averaged $30.32 per barrel, down from averaging over $100 per barrel in July 2014.

By mid-2016 crude oil prices began to rise and, subsequently, U.S. onshore rig count increased, reaching 1,054 by December 2018, and U.S. lower 48 onshore production reached a high of 9.5 million barrels per day in November 2018. As the rate of production grew throughout 2018, utilization on existing infrastructure began to increase in areas like the Permian Basin in West Texas, causing differentials between crude oil in West Texas and Cushing, Oklahoma (the U.S. pricing benchmark) to widen to nearly $18 per barrel in August 2018.

Source: EIA

Table of Contents

Source: EIA

U.S. Crude Oil Exports

The number of countries receiving exported U.S. crude oil has continued to rise since the removal of restrictions on exporting U.S. crude oil in December 2015. U.S. crude oil exports averaged 1.93 million barrels per day in the first eleven months of 2018, 0.77 (67%) million barrels per day more than the full-year 2017 and 1.34 (227%) million barrels per day more than full year 2016. During the week of November 30, 2018, the U.S. was a net exporter of crude oil and petroleum products for the first time in weekly data going back to 1991. Continued increases in U.S. crude oil exports will likely depend on increases in U.S. crude oil production and wider price differences between domestic and international crude oil. The table below depicts historical U.S. crude oil exports as reported by the EIA (see EIA website at www.eia.doe.gov):

	Annual U.S. Exports of Crude Oil				Δ from	Δ from	Δ from
	2015	2016	2017	2018 (1)	2015-2016	2016-2017	2017-2018 (1)
	(in millions of barrels per day) (2)						
PADD 1	0.07	0.17	0.01	0.03	0.10	(0.16)	0.02
PADD 2	0.08	0.11	0.21	0.13	0.02	0.11	(0.08)
PADD 3	0.29	0.29	0.92	1.76	—	0.63	0.84
PADD 4	0.01	0.01	—	—	—	(0.01)	—
PADD 5	0.01	0.01	0.01	0.01	—	—	—
Total U.S. Crude Oil Exports	0.47	0.59	1.16	1.93	0.13	0.57	0.77

(1) Data reflects actuals through November 2018.
(2) Amounts may not recalculate due to rounding.

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.

Table of Contents

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

- Ethane (C2). 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 (C3). 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 (C4). 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 of NGL supply (approximately 90% in the United States and 73% in Canada) 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 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 8% of the United States supply and 4% of Canadian supply and are by-products of the refinery conversion process. 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 (primarily propane and butane) is also imported into certain regions of the United States from Canada and other parts of the world (approximately 3% of total supply). 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 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.

Table of Contents

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 and the increase in export capacity has shifted regional basis relationships and created new logistics and infrastructure opportunities. Growth of 13% in 2018 for North American 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.

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. 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 during high-demand periods 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 supply 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.

16

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 highlight our more significant assets (including certain assets under construction or development) as of December 31, 2018. Unless the context requires otherwise, references herein to our "facilities" includes all of the pipelines, terminals, storage and other assets owned by us.

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, pipeline capacity agreements and other transportation fees. Our Transportation segment also includes equity earnings from our investments (ranging from 20% to 65%) in entities that own transportation assets. We account for these investments under the equity method of accounting. See Note 9 to our Consolidated Financial Statements for additional information regarding these investments.

As of December 31, 2018, we employed a variety of owned or, to a much lesser extent, leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 17,965 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 and help maintain product quality segregation;
- 830 trailers (primarily in Canada); and
- 50 transport and storage barges and 20 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, 2018, grouped by geographic location:

Region	Ownership Percentage	Approximate System Miles (1)	2018 Average Net Barrels per Day (2)
			(in thousands)
Crude Oil Pipelines:			
Permian Basin:			
Gathering pipelines	100%	2,970	1,063
Intra-basin pipelines (3)	50% - 100%	755	1,650
Long-haul pipelines (3)	20% - 100%	1,310	1,019
		5,035	3,732
South Texas/Eagle Ford	50% - 100%	660	442
Central	50% - 100%	2,695	473
Gulf Coast (3)	54% - 100%	1,170	178
Rocky Mountain (3)	21% - 100%	3,395	284
Western	100%	555	183
Canada	100%	2,790	316
Crude Oil Pipelines Total		16,300	5,608
Canadian NGL Pipelines	21% - 100%	1,665	183
Crude Oil and NGL Pipelines Total		17,965	5,791

(1) Includes total mileage from pipelines owned by unconsolidated entities.

Table of Contents

(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 may be included multiple times as volumes move through our integrated system.

(3) Includes pipelines operated by a third party.

A significant portion of our pipeline assets are interconnected and are operated as a contiguous system. The following descriptions are organized by geographic location and represent a selection of our most significant assets. Pipeline capacities throughout these descriptions are based on our reasonable estimate of volumes that can be delivered from origin to final destination on our pipeline systems. We report pipeline volumes based on the tariffs charged for individual movements, some of which may only utilize a certain segment of a pipeline system (i.e. two short-haul movements on a pipeline from point A to point B and another point B to point C would double the pipeline tariff volumes on a particular system versus a point A to point C movement). As a result, at times, our reported tariff barrel movements may exceed our total capacity.

Crude Oil Pipelines

Permian Basin

We are among the largest providers of crude oil midstream infrastructure and services in the Permian Basin located in west Texas and southeastern New Mexico. Our Permian Basin asset base represents an interconnected system that aggregates receipts from wellhead gathering lines and bulk truck injection locations into intra-basin trunk lines for transportation and delivery to a combination of owned and third-party mainline takeaway pipelines. Accordingly, our Permian Basin crude oil pipelines fall into one of three categories: Gathering, Intra-basin or Long-haul.

Gathering Pipelines

We own and operate approximately 2,970 miles of gathering pipelines in the Permian Basin. Our gathering systems are in both the Midland Basin and the Delaware Basin and in aggregate represent approximately 2 million barrels per day of pipeline capacity. This gathering capacity includes pipeline capacity that delivers volumes to regional hubs and includes certain large diameter pipeline segments/systems. Approximately 75% of the capacity of our gathering systems is in the Delaware Basin. We currently expect to add approximately 600,000 barrels per day of capacity in 2019.

Intra-basin Pipelines

We operate an intra-basin Permian Basin pipeline system with a capacity of over 2 million barrels per day that connects gathering and truck injection volumes to our owned and operated as well as third-party mainline pipelines that transport crude oil to major market hubs. This interconnected pipeline system is designed to provide shippers flow assurance, flexibility and access to multiple markets. We added approximately 500,000 barrels per day of incremental capacity in 2018 through the completion of various expansion projects, and we currently expect to add approximately 400,000 barrels per day of capacity in 2019.

Two of our largest intra-basin pipelines are the Mesa and Sunrise Pipelines. The Mesa and Sunrise Pipelines extend from our Midland, Texas terminal to our Colorado City, Texas terminal where they have access to all of the Permian Basin takeaway pipelines that originate at Colorado City.

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

- Sunrise Pipeline. Our Sunrise Pipeline, which transports crude oil from Midland, Texas to connecting carriers at Colorado City, Texas, has a capacity of approximately 350,000 barrels per day.

Table of Contents

Long-haul Pipelines

We own interests in multiple long-haul Permian Basin pipeline systems that, on a combined basis, represent approximately 1 million barrels per day of currently operational takeaway capacity (net to our ownership interests) out of the Permian Basin.

- Basin Pipeline (Permian to Cushing). We own an 87% undivided joint interest in and are the operator of Basin Pipeline. Basin Pipeline has three primary origination locations: Jal, New Mexico; Wink, Texas; and Midland, Texas and, in addition to making intra-basin movements, serves as the primary route for transporting crude oil from the Permian Basin to Cushing, Oklahoma. Basin Pipeline also receives crude oil from a facility in southern Oklahoma which aggregates South Central Oklahoma Oil Province (SCOOP) production.

- BridgeTex Pipeline (Permian to Houston). After the sale of a portion of our interest in the third quarter of 2018, we now own a 20% interest in BridgeTex Pipeline Company, LLC, a joint venture with a subsidiary of Magellan Midstream Partners, L.P. ("Magellan") and an affiliate of OMERS Infrastructure Management Inc. Such joint venture owns a crude oil pipeline (the "BridgeTex Pipeline") with a capacity of 440,000 barrels per day that originates at Colorado City, Texas, receiving volumes from our Basin and Sunrise Pipelines, and extends to Houston, Texas. The BridgeTex Pipeline is operated by Magellan. See Note 9 to our Consolidated Financial Statements for additional information regarding the sale of a portion of our interest in BridgeTex Pipeline Company, LLC.

- Sunrise II Pipeline. In 2018, as part of our Sunrise expansion project, we added 500,000 barrels per day of capacity by looping the line from Midland, Texas to Colorado City, Texas and extended the line from Colorado City, Texas to Wichita Falls, Texas. We sold 100,000 barrels per day of the new capacity from Midland, Texas to Wichita Falls, Texas to a third party. We operate the Sunrise II Pipeline and own 400,000 barrels of the capacity. The Sunrise expansion is underpinned by long-term shipper commitments and was placed into service in November 2018. Our Sunrise II Pipeline transports crude oil from Midland, Texas and Colorado City, Texas to connecting carriers at Wichita Falls, Texas.

- Cactus Pipeline (Permian to Corpus Christi). We own and operate the Cactus Pipeline, which has a capacity of 390,000 barrels per day, originates at McCamey, Texas and extends to Gardendale, Texas. Cactus Pipeline volumes are interconnected to the Corpus Christi, Texas market through a connection at Gardendale, Texas to our Eagle Ford joint venture pipeline system.

- Cactus II Pipeline (Permian to Corpus Christi). Cactus II Pipeline is a joint-venture pipeline, of which we own 65%, that is currently under construction. Cactus II Pipeline will be a new Permian mainline system extending directly to the Corpus Christi, Texas market. In February 2018, we announced that Cactus II Pipeline was fully committed with long-term third-party contracts following the conclusion of a second binding open season. Cactus II Pipeline will have a capacity of 670,000 barrels per day and is expected to be placed into partial service in the second half of 2019.

- Wink to Webster Pipeline. In January 2019, we announced the formation of Wink to Webster Pipeline LLC ("W2W Pipeline"), a joint venture with subsidiaries of ExxonMobil and Lotus Midstream, LLC. We own a 20% interest in W2W Pipeline, which is currently developing a new pipeline system that will originate in the Permian Basin in West Texas and transport crude oil to the Texas Gulf Coast. The pipeline system will provide more than 1 million barrels per day of crude oil and condensate capacity, and the project is targeted to commence operations in the first half of 2021.

South Texas/Eagle Ford Area

We own a 100% interest in and are the operator of gathering systems that feed into our Gardendale Station. Additionally, we own a 50% interest in Eagle Ford Pipeline LLC, a joint venture with a subsidiary of Enterprise

Products Partners, L.P. ("Enterprise"). This joint venture owns a pipeline system, of which we serve as the operator, that has a total capacity of approximately 660,000 barrels per day and connects Permian and Eagle Ford area production to Corpus Christi, Texas refiners and terminals. Additionally, the joint venture system has connectivity to Houston, Texas via a connection with Enterprise's pipeline at Lyssy, Texas.

Central

We own and operate gathering and mainline pipelines that source crude oil from Western and Central Oklahoma and Southwest Kansas for transportation and delivery into our terminal facilities at Cushing, Oklahoma. In addition, we own and operate various pipeline systems that extend from our Cushing facility, or from other pipelines connected to our Cushing facility, to various demand locations. Below is a description of some of our most significant pipeline systems in the Central Region:

Diamond Pipeline (Cushing to Memphis). We own a 50% interest in Diamond Pipeline LLC, a joint venture with Valero Energy Corporation (“Valero”). This joint venture owns, and we operate, the Diamond Pipeline, which extends from our Cushing Terminal to Valero’s refinery in Memphis, Tennessee. The Diamond Pipeline is underpinned by a long-term minimum volume commitment and currently has a total capacity of 200,000 barrels per day, which is expandable by an additional 200,000 barrels per day as conditions warrant. Pending a successful open season on the Capline Pipeline system (“Capline”), the joint venture partners are contemplating an expansion and modest extension of the Diamond Pipeline that would connect to Capline and facilitate the movement of volumes from Cushing, Oklahoma to St. James, Louisiana (see discussion below).

Red River Pipeline (Cushing to Longview). The Red River Pipeline is an approximately 150,000 barrel per day capacity pipeline that extends from our Cushing Terminal to Longview, Texas, where it connects with various pipelines, including the Caddo Pipeline. We have an undivided 60% interest in the segment of the pipeline extending from Cushing, Oklahoma to Hewitt, Oklahoma near Valero’s refinery in Ardmore, Oklahoma. We have a 100% interest in the remaining portion of the pipeline that extends from Hewitt, Oklahoma to Longview, Texas. The Red River Pipeline is supported by long-term shipper commitments and we serve as operator.

Caddo Pipeline. We own a 50% interest in Caddo Pipeline LLC, a joint venture with Delek Logistics Partners, LP (“Delek”). The joint venture owns, and we operate, the Caddo Pipeline, which is an approximately 80,000 barrel per day capacity pipeline that originates in Longview, Texas at the terminus of the Red River Pipeline and serves refineries in Shreveport, Louisiana and El Dorado, Arkansas. The Caddo Pipeline is underpinned by shipper commitments.

STACK Pipeline. We own a 50% interest in STACK Pipeline LLC, a joint venture with Phillips 66 Partners, L.P. This joint venture owns the STACK Pipeline, which serves producers in the STACK (Sooner Trend Anadarko Basin Canadian and Kingfisher Counties) resource play and delivers to Cushing, Oklahoma. We serve as operator of this joint-venture system that has a total capacity of 250,000 barrels per day and is supported by producer commitments.

Gulf Coast

We own and/or operate pipelines in the Gulf Coast area with transportation and delivery into connecting carriers, terminal facilities and refineries. This includes a 54% interest in Capline. In January 2019, the owners of Capline converted their undivided joint interests into a limited liability company and launched a binding open season to solicit shipper interest for a reversal of Capline and the initiation of southbound service on Capline from Patoka, Illinois to St. James, Louisiana and potentially on our Diamond Pipeline and Capline from Cushing, Oklahoma to St. James, Louisiana.

Rocky Mountain

We own and operate pipelines that provide gathering services in the Bakken and the Powder River Basin. We own a pipeline system that can move Bakken crude oil to the Enbridge mainline system at Regina, Saskatchewan. In 2019, the pipeline will be modified to accommodate bidirectional flow, either from the Bakken into the Enbridge mainline system or from the Enbridge mainline system to our terminal in Trenton, North Dakota. We own an undivided joint interest in a pipeline system that extends from the Canadian border to our terminal in Guernsey, Wyoming. This pipeline system receives crude oil from our Rangeland and Milk River Pipelines in Canada. In addition to these assets, our largest Rocky Mountain area systems include the following joint venture pipelines, both of which connect to our terminal in Cushing:

Saddlehorn Pipeline. We own a 40% interest in Saddlehorn Pipeline LLC (“SP LLC”), which owns 190,000 barrels per day of capacity in the Saddlehorn Pipeline that extends from the Niobrara and DJ Basin to Cushing. Magellan serves as operator of the Saddlehorn Pipeline. The Saddlehorn Pipeline is supported by minimum volume commitments.

White Cliffs Pipeline. We own an approximate 36% interest in White Cliffs Pipeline LLC, which currently consists of two crude oil pipelines with approximately 215,000 barrels per day of capacity that extend from the DJ Basin to Cushing, Oklahoma. Rose Rock Midstream, L.P. ("Rose Rock") serves as the operator of the pipelines. In the second quarter of 2019, the total capacity will be reduced to 110,000 barrels per day as one of the crude oil pipelines will be converted to a NGL pipeline with an initial capacity of 90,000 barrels per day. The NGL pipeline is expected to return to service in late 2019 and will extend form the DJ Basin to a tie-in location with the Southern Hills Pipeline in Oklahoma. The conversion to the NGL pipeline is supported by long-term capacity lease and long-term throughput agreements. Rose Rock will also operate the NGL pipeline.

Western

We own and operate pipeline systems in our Western region including the following:

Gathering. We own and operate gathering pipelines with aggregate capacity of over 150,000 barrels per day that source crude oil from the San Joaquin Valley in California and connect to our Line 63 and Line 2000 pipelines, as well as other third-party pipelines and terminals.

Line 63 and Line 2000. We own and operate the Line 63 and Line 2000 pipelines, which have approximately 60,000 barrels per day and 110,000 barrels per day of pipeline capacity, respectively, and transport crude oil from the San Joaquin Valley to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield, California. Additionally, we have a distribution pipeline system in the Los Angeles Basin that connects our storage assets with all major refineries and third-party pipelines and marine terminals in the Los Angeles Basin.

All American Pipeline. We own the All American Pipeline, which historically received 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 on the segment of the All American Pipeline known as Line 901 that runs from Las Flores to Gaviota 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 evaluating a replacement of the pipeline, subject to receipt of shipper commitments and regulatory approvals. See Note 18 to our Consolidated Financial Statements for additional information regarding the Line 901 incident.

Canada

Rainbow Pipeline. We own and operate the Rainbow Pipeline, which is an approximately 185,000 barrel per day capacity pipeline that extends from Zama, Alberta to Edmonton, Alberta. The pipeline transports both blended heavy and light crude oil and includes gathering and diluent pipelines. Rainbow Pipeline offers delivery optionality at Edmonton, Alberta, where it can connect to Enbridge, Trans Mountain and Pembina pipelines as well as IOL Refinery.

Rangeland Pipeline. We own and operate the Rangeland Pipeline system, which has the capacity to transport approximately 85,000 barrels per day of diluent, light sweet crude oil and light sour crude oil either north to Edmonton, Alberta or south to the U.S./Canadian border near Cutbank, Montana. The Rangeland Pipeline system consists of three main segments. The North Gathering system begins at Medicine River and Rimbey truck terminal, and ships to Sundre truck terminal. The South Sour mainline delivers sour from the Sundre truck terminal to Glacier Pipeline, and MAPL delivers sweet from Sundre to Edmonton. The Pipeline also offers delivery optionality at Edmonton, Alberta, where it can connect to Enbridge pipelines and the IOL Refinery.

South Saskatchewan Pipeline. We own and operate the South Saskatchewan system, which has approximately 70,000 barrels per day of capacity to transport heavy crude oil from the Cantuar, Dollard, Rapdan and Gull Lake gathering areas in southern Saskatchewan to the Enbridge mainline system at the Regina terminal.

Manito Pipeline. We own and operate the Manito Pipeline, which delivers heavy crude oil produced from the Lloydminster producing area of Alberta to our Kerrobert Terminal and our Kerrobert Rail Terminal. The Kerrobert Terminal is connected to both the Enbridge mainline system and our Kerrobert Rail Terminal. The Manito system includes blended crude oil lines with capacity of approximately 70,000 barrels per day and parallel diluent lines.

Table of Contents

Milk River Pipeline. We own and operate Milk River Pipeline system, which has approximately 100,000 barrels per day of capacity to transport heavy crude oil from Milk River, Alberta to the U.S./Canadian border west of Coutts, Alberta and connects with the Cenex Santa Rita Pipeline System in the U.S.

Wascana Pipeline. We own and operate the Wascana Pipeline, which has approximately 40,000 barrels per day of capacity to move sweet crude from the Bakken North pipeline system to Enbridge's mainline system at Regina, Saskatchewan. The Wascana Pipeline is currently undergoing modifications to add bi-directional capability.

Canadian NGL Pipelines

Co-Ed NGL Pipeline. We own and operate the Co-Ed NGL pipeline, which has approximately 70,000 barrels per day of capacity to transport NGL that it gathers from approximately 27 field gas processing plants located in Alberta, including all of the NGL produced at the Cochrane Straddle Plant for delivery to NGL facilities at Fort Saskatchewan. Co-Ed's main volume capture regions are Southwest and Central Alberta, Cardium, Deep Basin, and Alberta Montney.

PPTC Pipeline. We own and operate the Plains Petroleum Transmission Company Pipeline (the "PPTC Pipeline"), which has approximately 15,000 barrels per day of capacity to transport NGL from Empress, Alberta to the Fort Whyte Terminal in Winnipeg, Manitoba. The PPTC Pipeline also provides access to several truck terminals and rail loading facilities.

Eastern Delivery System. We own and operate the Eastern Delivery System, which has various segments that transport propane and butane between Sarnia, Ontario and Windsor, Ontario and from Sarnia, Ontario to St. Clair, Michigan; refinery grade butane between Windsor, Ontario and Woodhaven, Michigan; and syncrude from Sarnia, Ontario to local refineries. The Eastern Delivery System also receives ethane from Kinder Morgan Utopia Pipeline at Windsor, Ontario for delivery to petrochemical facilities in the Sarnia, Ontario area, as well as our facility in Sarnia, Ontario. These pipelines have a combined capacity of approximately 150,000 barrels per day.

Facilities Segment

Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services primarily for crude oil, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. We generate revenue through a combination of month-to-month and multi-year agreements and processing arrangements.

Revenues generated in this segment include (i) storage and throughput fees at our crude and NGL storage terminals and natural gas storage facilities, (ii) fees from natural gas and condensate processing services and from NGL fractionation and isomerization services and (iii) loading and unloading fees at our rail terminals.

As of December 31, 2018, we owned, operated or employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 77 million barrels of crude oil storage capacity primarily at our terminalling and storage locations;
- approximately 32 million barrels of NGL storage capacity;
- approximately 63 billion cubic feet ("Bcf") of natural gas storage working gas capacity;
- approximately 25 Bcf of owned base gas;
- seven 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;

- 33 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;
- five marine facilities in the United States; and
- approximately 425 miles of active pipelines that support our facilities assets.

Table of Contents

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, 2018, grouped by product and service type, with capacity and volume as indicated:

Crude Oil Storage Facilities	Total Capacity (MMBbls)
Cushing	25
St. James	13
LA Basin	8
Patoka	7
Mobile and Ten Mile	4
Other [(1)]	20
	77

NGL Storage Facilities	Total Capacity (MMBbls)
Fort Saskatchewan	10
Sarnia Area	9
Empress Area	4
Bumstead	3
Other	6
	32

Natural Gas Storage Facilities	Total Capacity (Bcf)
Salt Caverns	63

Natural Gas Processing Facilities [(2)]	Ownership Interest		Total Gas Spec Product [(3)] (Bcf/d)	Gas Processing Capacity (Bcf/d)
United States Gulf Coast Area	100	%	0.2	0.3
Canada	50-88%		2.5	7.1
			2.7	7.4

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

NGL Fractionation and Isomerization Facilities	Ownership Interest		Total Spec Product [(3)] (Bbls/d)	Net Capacity (Bbls/d)
Empress	100	%	17,100	28,300
Fort Saskatchewan	21-100%		41,000	67,800
Sarnia	62-84%		53,900	90,000
Shafter	100	%	9,500	15,000
Other	82-100%		9,800	25,000
			131,300	226,100

Table of Contents

Rail Facilities	Ownership Interest		Loading Capacity (Bbls/d)	Unloading Capacity (Bbls/d)
Crude Oil Rail Facilities	100	%	314,000	350,000

	Ownership Interest	Number of Rack Spots	Number of Storage Spots
NGL Rail Facilities (4)	50-100%	335	1,635

(1) Amount includes approximately 2 million barrels of storage capacity associated with our crude oil rail terminal operations.
(2) While natural gas processing volumes and capacity amounts are presented, they currently are not a significant driver of our segment results.
(3) Represents average volumes net to our share for the entire year.
(4) 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 Facilities

Cushing Terminal. We are the largest provider of crude oil terminalling services in Cushing, Oklahoma, which is one of the largest physical trading hubs in the United States and is the delivery point for crude oil futures contracts traded on the NYMEX. Our 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 certain Gulf Coast refiners.

Our Cushing Terminal is designed to serve the operational needs of refiners, with an emphasis on ensuring operational reliability and flexibility. Accordingly, we have access to all major inbound and outbound pipelines in Cushing (23 direct pipeline connections) and our facility 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 our Cushing Terminal.

St. James Terminal. The crude oil interchange at St. James, Louisiana is one of the three most liquid crude oil interchanges in the United States. Our 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 deliver to, tankers and barges and is also connected to our rail unloading facility. See "Rail Facilities" below for further discussion.

L.A. Basin. We own four crude oil and black oil storage facilities in the Los Angeles area with 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.

Patoka Terminal. Our Patoka Terminal includes crude oil storage and 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, a growing regional hub serving both northbound and southbound movements.

Mobile and Ten Mile Terminal. We have a marine terminal in Mobile, Alabama (the “Mobile Terminal”) and a terminal at our nearby Ten Mile Facility. The facilities are pipeline connected. 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 and our Ten Mile Facility is connected to our Pascagoula Pipeline.

Table of Contents

Corpus Christi (Eagle Ford) Terminal. We own a 50% interest in Eagle Ford Terminals Corpus Christi LLC, 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 with either crude oil or condensate. 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 into service in the second quarter of 2019.

NGL Storage Facilities

Fort Saskatchewan. The Fort Saskatchewan facility is located near 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 27 storage caverns. 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.

Sarnia Area. Our Sarnia Area facilities in Southwestern Ontario 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 and storage facility located in the Sarnia Chemical Valley that contains multiple rail and truck loading spots. The Sarnia Area facilities are served by a network of 15 pipelines connected to various refineries, chemical plants and other pipeline systems in the area. This pipeline network also delivers product between our Sarnia facility and our Windsor storage terminal in addition to the delivery capability from our Sarnia facility to our St. Clair terminal.

Empress Area. We own a network of seven NGL terminals (Fort Whyte, Moose Jaw, Rapid City, Stewart Valley, Dewdney, Empress and Richardson). The facilities are complemented by various other NGL fractionation and extraction assets as described further below.

Bumstead. Our Bumstead facility is located at a major rail transit point near Phoenix, Arizona. The facility’s primary assets include salt-dome storage caverns, a rail track and truck racks.

Natural Gas Storage Facilities

We own two U.S. Federal Energy Regulatory Commission (“FERC”) regulated natural gas storage facilities located on the Gulf Coast that are certificated for 112 Bcf of working gas capacity, and as of December 31, 2018, we had an aggregate commercial working gas capacity of approximately 63 Bcf in service. Our facilities have aggregate certificated peak daily injection and withdrawal rates of 3.6 Bcf and 5.6 Bcf, respectively.

Our two natural gas storage facilities are strategically located within the Gulf Coast market and have a diverse group of customers, including liquefied natural gas (“LNG”) exporters, utilities, pipelines, producers, power generators and marketers whose storage needs vary from traditional seasonal storage services to hourly balancing. We are located near several major market hubs and our facilities have 14 physical interconnects with third-party interstate pipelines, intrastate pipelines and direct connect customers, serving markets in the Gulf Coast, Mid-Atlantic, Northeast, and Southeast regions of the United States.

Natural Gas Processing Facilities

We own and/or operate four straddle plants located in Western Canada. In addition to the processing capacity at our straddle plants, we have 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.

NGL Fractionation and Isomerization Facilities

Empress. We own the Empress fractionation facility, which is connected to and receives liquids from our Empress straddle plant. The facility is capable of producing spec NGL products and connects to our PPTC Pipeline network.

Fort Saskatchewan. Our recently expanded Fort Saskatchewan fractionation facility has a design capacity of 85,000 barrels per day and produces spec propane, butane, condensate and a propane and butane mix, which is sent to our Sarnia facility for further fractionation. 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.

Table of Contents

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 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.

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, Texas. The facility has a total processing capacity of 120,000 barrels per day and usable 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 facilities located at or near Carr, Colorado; Tampa, Colorado; Gardendale, Texas; McCamey, Texas; Manitou, North Dakota; and Kerrobert, Saskatchewan.

Crude Oil Rail Unloading Facilities

We own three crude oil rail unloading facilities. Our St. James, Louisiana facility receives unit trains and has a capacity of 140,000 barrels per day. Our Yorktown, Virginia rail facility can receive unit trains and has an unload capacity of approximately 140,000 barrels per day. Our Bakersfield, California rail facility receives unit trains and has permitted capacity to unload 70,000 barrels per day.

NGL Rail Facilities

We own 26 operational NGL rail facilities (including our Fort Saskatchewan rail facility, as well as facilities that can provide both crude oil and NGL service) strategically located near NGL storage, pipelines, gas production or propane distribution centers throughout the United States and Canada. We have the ability to switch our own railcars at eight of our facilities. We are currently in the process of commissioning rail offload capability at Tampa, Florida, which will add 14 unloading spots and room to store 14 cars, with total capacity of 28 cars on site at a time.

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, and the bulk purchase of crude oil at pipeline, terminal and rail facilities;
- 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 extraction of NGL from gas processed at our facilities;
- the resale or exchange of crude oil and NGL at various points along the distribution chain to refiners, operators of petrochemical facilities, exporters or other resellers; and
- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and vessels from various delivery points, market hub locations or directly to end users such as refineries, processors and fractionation facilities.

Table of Contents

Our purchase and resale of crude oil and NGL results in us generating a margin, which is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil or NGL to market as well as related operating and general and administrative expenses. A portion of our results is impacted by overall market structure and the degree of market volatility, as well as variable operating expenses. Our activities are designed to limit downside exposure, while generating upside potential associated with opportunities inherent in volatile market conditions (including opportunities to benefit from fluctuating differentials and market structure). Opportunities to realize upside potential through our Supply and Logistics operations occur from time to time and are typically for short periods of time when there are local or regional infrastructure constraints. 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, 2018, our Supply and Logistics segment 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:

- 15 million barrels of crude oil and NGL linefill in pipelines owned by us;
- 4 million barrels of crude oil and NGL utilized as linefill in pipelines owned by third parties or otherwise required as long-term inventory;
- 750 trucks and 900 trailers; and
- 9,100 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.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2018:

	Volumes (MBbls/d)
Crude oil lease gathering purchases	1,054
NGL sales	255
Supply and Logistics segment total volumes	1,309

Crude Oil and NGL Purchases. We purchase crude oil and NGL from multiple producers under contracts and believe 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 ten years. We utilize our truck fleet, railcars and pipelines as well as leased railcars, third-party pipelines, trucks and barges to transport 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 also acquire NGL from gas shippers by paying an extraction right to remove the liquids from the gas flowing through our straddle plants at Empress, Alberta. We utilize our trucking fleet and pipeline network, as well as leased railcars, third-party tank trucks and third-party pipelines to transport NGL.

Table of Contents

In addition to purchasing crude oil from producers, we purchase both domestic and foreign crude oil in bulk at major hub locations, rail and dock facilities. We also purchase NGL in bulk at major pipeline terminal points and storage facilities from major integrated oil companies, large independent producers or other NGL marketing companies or processors. Crude oil and NGL are purchased in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or NGL distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

Crude Oil and NGL Sales. The activities involved in the supply, logistics and distribution of crude oil and NGL are complex and require current detailed knowledge of crude oil and NGL sources and end markets, as well as a familiarity with a number of factors including 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 typically put in place to ensure any significant cost escalations are accounted for, which may include provisions for annual price negotiations designed 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 we enter into exchanges based on the grade of crude oil, which includes such factors as sulfur content and specific gravity, in order to meet the quality specifications of our physical delivery contracts. See Note 2 to our Consolidated Financial Statements for further discussion of our accounting for exchange and buy/sell agreements.

Credit. Our merchant activities involve the purchase of crude oil and NGL 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 and NGL, we must determine the amount, if any, 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. Additionally, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Furthermore, we also enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet) for the majority of our net-cash arrangements.

Because our typical sales transactions can involve large volumes of crude oil, the risk of nonpayment and nonperformance by customers is a major consideration in our business. We believe our sales are made to creditworthy entities or entities with adequate credit support. Generally, sales of crude oil are settled within 30 days of the month of delivery, and pipeline, transportation and terminalling services settle within 30 days from the date we issue an invoice for the provision of services.

We also have credit risk exposure related to our sales of NGL (principally propane); however, because our sales are typically in relatively small amounts to individual customers, we do not believe that these transactions pose a material concentration of credit risk. Typically, we enter into annual contracts to sell NGL on a forward basis, as well as to sell NGL on a current basis to local distributors and retailers. In certain cases our NGL customers prepay for their purchases, in amounts ranging up to 100% of their contracted amounts.

Certain activities in our Supply and Logistics segment are affected by seasonal aspects, primarily with respect to NGL supply and logistics activities, which are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March.

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 2018, WTI crude oil prices traded within a range of approximately $43 to $76 per barrel. There has also been volatility within the propane and butane markets as seen through the North American benchmark price located at Mont Belvieu, Texas. Specifically, over the last ten years, propane prices have ranged from a low of approximately 30% of the WTI benchmark price for crude oil in 2015 to a high of approximately 75% of the WTI benchmark price for crude oil in 2017. During 2018, propane averaged 57% of WTI and on a daily basis traded within a range of 49% to 68% of WTI. During the same ten-year period, butane has seen a price range from a low of approximately 35% of the WTI benchmark price for crude oil in 2015 to a high of approximately 108% of the WTI benchmark price for crude oil in 2017. During 2018, butane averaged 66% of WTI and on a daily basis traded within a range of 55% to 77% of WTI.

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 (absent material outperformance in our Supply and Logistics business) our fee-based Transportation and Facilities segments should comprise approximately 90% or greater of our aggregate segment results.

Results from our supply and logistics activities depend 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 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 through early 2018, however, the market experienced impacts from aggressive competition and overbuilt infrastructure in certain regions, which 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 to satisfy 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 margins across our three business segments. During such transitional markets, our Supply and Logistics segment may not be able to fully recover its costs on certain transactions.

Table of Contents

In challenging market conditions, such as those experienced over the last several years, 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 provides flexibility for our customers and plays a valuable role in driving the growth of our fee-based Transportation and Facilities segments. Additionally, 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.

In executing our business model, we employ a variety of financial risk management tools and techniques, predominantly in our Supply and Logistics segment. These are discussed in greater detail below.

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 of 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 trading activities. 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.

Customers

Marathon Petroleum Corporation and its subsidiaries accounted for 14%, 19% and 18% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively. ExxonMobil Corporation and its subsidiaries accounted for 14%, 11% and 14% of our revenues for the years ended December 31, 2018, 2017 and 2016, respectively. Phillips 66 Company and its subsidiaries accounted for 11% of our revenues in each of the years ended December 31, 2017 and 2016. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2018. 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 15 to our Consolidated Financial Statements.

Table of Contents

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. Although new pipeline projects represent a source of competition for our business, there are also existing third-party owned pipelines with excess capacity in the vicinity of our operations that expose us to significant competition based on the relatively low operating cost associated with moving an incremental barrel of crude oil or NGL through such unutilized capacity. In the current environment, 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 sustainable demand levels. For example, over the last 18 months, several potential new pipeline projects have been announced or are currently under construction. In many cases the sponsors have represented that such projects are underpinned by substantial minimum volume commitments and/or acreage dedications. Combined with current pipeline takeaway capacity, these proposed or pending pipeline projects could result in significant excess capacity relative to projected crude oil production volumes, especially in the Permian Basin, where we have significant operations. In combination with incremental shipper commitments or dedications, the ratio of excess capacity to uncommitted barrels is expected to increase significantly, amplifying the competition for incremental barrels to fill available capacity on our assets and resulting in downward pressure on margins.

In addition, 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 truck, 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. The addition of new pipelines supported by minimum volume commitments and/or acreage dedications could also amplify the level of competition for purchasing wellhead barrels, especially in the Permian Basin and thus impact our margins.

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 storage facilities connected to their systems that compete with some of our facilities.

Regulation

Our assets, operations and business activities are subject to extensive legal requirements and regulations under the jurisdiction of numerous federal, state, provincial and local agencies. Many of these agencies are authorized by statute to issue, and have issued, requirements binding on the pipeline industry, related businesses and individual participants. The failure to comply with such legal requirements and regulations can result in substantial fines and penalties, expose us to civil and criminal claims, and cause us to incur significant costs and expenses. 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. The current laws and regulations affecting our business are subject to change and in the future we may be subject to additional laws and regulations, which could adversely impact our business.” 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 summary 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 as regulations are updated or new regulations are invoked. 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 or other orders that may subject us to additional operational constraints. Failure to comply with these laws and regulations could also result in negative public perception of our operations or the industry in general, which may adversely impact our ability to conduct our business. 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 Department of Transportation's ("DOT") 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 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 $86 million in 2018, $137 million in 2017 and $89 million in 2016. Based on currently available information, our preliminary estimate for 2019 is that we will incur approximately $69 million in capital expenditures and approximately $28 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 in connection with these voluntary initiatives were approximately $38 million in 2018, $39 million in 2017 and $48 million in 2016, and our preliminary estimate for 2019 is that we will incur approximately $52 million of such costs.

PHMSA was reauthorized and the HLPSA was amended in 2011 and 2016. The regulatory changes precipitated by these actions have increased our cost to operate. We anticipate that future rulemaking (including the 2019 reauthorization of PHMSA and the eventual adoption of the hazardous liquids rule) will have the potential to contribute to a higher cost to operate.

Table of Contents

In October 2015, the Governor of California signed the Oil Spill Response: Environmentally and Ecologically Sensitive Areas Bill ("AB-864") which requires new and existing pipelines located near environmentally and ecologically sensitive areas connected to or located in the coastal zone to use best available technologies to reduce the amount of oil released in an oil spill to protect state waters and wildlife. Best available technology includes, but is not limited to, installation of leak detection technologies, automatic shutoff systems, or remote controlled sectionalized block valves, or any combination of these technologies based on a risk analysis conducted by the operator. The California Office of the State Fire Marshal is in the process of developing the regulations required by AB 864 and issued updated draft regulations in January 2019. The updated draft regulations (while not yet adopted) require that the risk analysis, plans for installation of best available technology and any exemption requests be submitted in 2020 and installation of best available technology, if required, be completed by July 2022. These deadlines could change depending upon the date the final regulations are adopted. Compliance with these new regulations will impact our pipeline operations in California and add to the cost to operate the pipelines subject to these rules.

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; however, we cannot provide any assurance that these security measures would fully protect our facilities from an attack.

The DOT has generally 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 $53 million, $37 million and $29 million in 2018, 2017 and 2016, respectively. For 2019, we have budgeted approximately $51 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 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.

We have implemented Pipeline, Facility and Cavern Integrity Management Programs to comply with applicable regulatory requirements and assist in our efforts to mitigate risk. Costs incurred for such integrity management activities were approximately $71 million, $60 million and $59 million in 2018, 2017 and 2016, respectively, and our preliminary estimate for 2019 is that we will incur approximately $76 million of such costs.

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, pursuant to a settlement agreement with environmental organizations, the EPA must determine by 2019 whether currently exempt oil and gas wastes should be regulated under RCRA's hazardous waste provisions.

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 Environmental Protection Agency's ("EPA") Risk Management Plan regulations at certain facilities. These regulations are intended to work with OSHA's PSM regulations 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 January 2016, the EPA finalized revisions to the Risk Management Plan ("RMP") rules, including requirements for the use of third-party compliance audits, root cause analyses for facilities that experience releases, process hazard analyses and enhanced information-sharing provisions, effective March 2017. However, the EPA has since published a rule delaying implementation of the RMP revisions until February 2019 while the agency considers whether to amend or repeal the rule. OSHA has announced that it is considering similar revisions to the PSM rule, but, to date, has not issued a Notice of Proposed Rulemaking. The potential for revisions to either the RMP or PSM rule is uncertain at this time.

Environmental Remediation

We currently own or lease, and in the past have owned or leased, properties where potentially 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 potentially 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 hydrocarbon products into the environment from our pipeline, rail, storage and other facility operations. We may also discover environmental impacts from past releases that were previously unidentified. The costs and liabilities associated with any such releases or environmental impacts could be significant and may not be covered by insurance; accordingly, such costs and liabilities could have a material adverse impact on our results of operations and/or financial position.

Air Emissions

Our United States operations are subject to the United States Clean Air Act ("Clean Air Act"), comparable state laws and associated state and federal regulations. Our Canadian operations are also subject to federal and provincial air emission regulations, which are discussed in subsequent sections.

As a result of the changing air emission requirements in both Canada and the United States, 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 air 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 the emission 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.

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. However, the EPA has taken several steps to delay implementation of its methane rules, and the agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of the methane rules in their entirety. The EPA has not yet published a final rule but, as a result of these developments, future implementation of the 2016 rules is uncertain at this time. However, several states have either proposed or finalized similar regulations related to the reduction of methane emissions from the oil and natural gas sector.

California has implemented a GHG cap-and-trade program, authorized under Assembly Bill 32 ("AB32"). Since its start in 2014, California's cap-and-trade program has only applied to large industrial facilities with carbon dioxide equivalent emissions over 25,000 metric tons. 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 and propane fractionation source. As a result, compliance instruments for GHG emissions have been purchased since 2013.

Effective January 1, 2015, the AB32 regulations also covered finished fuel providers and importers. California finished fuels providers (refiners and importers) are 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 compliance requirements of the GHG cap-and-trade program through 2020 are currently being phased in. Effective January 1, 2018, importers of finished fuels responsible for compliance costs associated with GHG has changed from the consignee to the importer on title of the product. Plains Midstream Canada is now included in this change to the rule due to its imports of propane into California and will submit its first compliance report in 2019.

Executive Order B-30-15 was signed by California's Governor in mid-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.

Table of Contents

While it is not possible at this time to predict how federal or state governments may choose to regulate GHG emissions, any new regulatory 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. The United States and Canada are currently signatories to the Agreement; however, in June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. In August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. The Paris Agreement is likely to become a significant driver for future potential GHG reduction programs in participating countries. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Finally, to the extent increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on our assets, particularly those located in coastal or flood prone areas.

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 197 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. Further, on December 12, 2015, the UNFCCC ratified the Paris Agreement to accelerate climate change initiatives and to intensify the actions of member nations in the reduction of GHG emissions. This ratification also included requirements that all Parties report on their emissions status and agreement for a review every five years to assess success among member nations in attaining objectives and targets under this agreement.

Large emitters of GHG have been required to report their emissions under the Canadian Greenhouse Gas Emissions Reporting Program since 2004. Effective January 1, 2018, the Federal Department of Environment and Climate Change lowered the reporting threshold for all facilities from 50 thousand tonnes per year ("kt/y") to 10 kt/y GHG emissions. This has resulted in one additional PMC facility (for a total of four locations) being currently required to prepare annual reports of their emissions. The associated costs with this new reporting requirement is not considered to be material.

In October 2016, the Government of Canada implemented a pan-Canadian approach to pricing carbon pollution requiring all Canadian provinces and territories to have carbon pricing in place by 2018, which is now in effect. The provinces and territories were granted 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 Provincial programs that fail to meet the Federal government's requirements for their programs are required to adopt the Federal program. The Federal program includes two components: a direct price on carbon pollution (the Federal price on carbon pollution will start at

$20/tonne in 2019 and rise by $10 a year to reach $50/tonne in 2022) and an output based pricing system ("OBPS") designed to address competitiveness risk for large emitters.

In April 2018, the Federal Department of Environment and Climate Change introduced regulations designed to reduce methane emissions by up to 45% by 2025 (from 2012 levels) from oil and natural gas facilities. The scope and requirements of the proposed rule are similar to the EPA methane rules described above. Effective June 2017, the Federal Department of Environment and Climate Change has introduced the Multi Sector Air Pollutants Regulations which set air pollution emission standards across Canada for several industrial sectors that utilize applicable equipment regulated under this program. The regulations establish specific limits to the amount of nitrogen oxides emitted from gas fueled boilers, heaters and stationary spark-ignition engines above a specified power rating. Based on these regulations, reporting obligations exist that are associated with seven facilities with equipment that meets specifications of the program. The implications of these regulations coming into effect are not believed to be material.

Table of Contents

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 were responsible for their emissions starting on January 1, 2017. PMC’s facility at Sarnia was considered to be a mandatory participant in the program. In June 2018, the newly formed Ontario Provincial government repealed the provincial cap and trade program with the passing of the Cap and Trade Cancellation Act which now subjects the province to the Federal carbon pricing program. At this time, we do not believe that the cancellation of Ontario’s cap and trade program, or replacement with the Federal program, will have a material adverse effect on our operations.

The Ontario government has introduced an updated Sulphur Dioxide (“SO2”) standard which requires the reduction of SO2 from the current one hour average emission rate of 690 micrograms per cubic meter of air (“ug/m3”) to the new one hour standard of 100 ug/m3 by 2023 at industrial facilities. The introduction of this reduction measure will require further evaluation of current emissions and further measures to be implemented based on initial emission testing. The impact of this requirement is not known at this time.

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 Specified Gas Emitters Regulation (“SGER”) was the initial program introduced which imposed GHG emissions limits on large emitters and required reductions in GHG emissions intensity. PMC has two facilities (Fort Saskatchewan Storage and Fractionation Facility and Empress VI) which do not meet the reduction obligations. As such, PMC has been required to submit compliance payments to the Climate Change Emissions Management Fund. In January 2018, the SGER was replaced with the Carbon Competitive Incentive Regulation (“CCIR”) for compliance years 2018 onwards. Although various elements of the SGER are carried through into the CCIR, the CCIR has fundamental differences, both in the way a facility’s regulated emissions are calculated as well as how the emission intensity reduction is measured, which aligns with the program developed by the Federal government and their OBPS requirements. Compliance options under the CCIR are similar to those under the previous SGER such that a GHG fund credit purchase is required if reduction targets identified under the program are not attained, which has historically resulted in payments being made to the province for the two facilities under this program.

In association with the Federal methane reduction targets, the Alberta government has introduced the Alberta Methane reduction program, which requires a 45% reduction of methane from oil and gas operations by 2025. The primary focus will be on the improvement of measurement and reporting, and leak detection programs which will be formalized internally within existing operational budgets.

Other Canadian Jurisdictions. Nova Scotia and Quebec Cap and Trade programs cover propane supplied by PMC into the Nova Scotia and Quebec markets. PMC is required to purchase GHG emission credits and submit annual compliance reports under each province’s respective Cap and Trade program. Effective April 1, 2019, the Federal carbon pricing program comes into effect for provinces that do not have a carbon pricing program in place. This includes Saskatchewan, Manitoba, Ontario and New Brunswick.

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.

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, and can also pursue injunctive relief to enforce compliance with the CWA and analogous laws.

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.

Table of Contents

In addition, for over 35 years, the Army Corps of Engineers (the “Corps”) has authorized construction, maintenance and repair of pipelines under a streamlined nationwide permit program under the CWA 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. This clarification greatly expanded the definition of “waters of the United States” thus increasing the jurisdiction of the Corps. A number of legal challenges to this rule are pending. Additionally, following the issuance of a presidential executive order to review the rule, the EPA and the Corps proposed a rulemaking in June 2017 to repeal the May 2015 rule. The EPA and Corps also announced their intent to issue a new rule defining the CWA’s jurisdiction and recently finalized a stay delaying implementation of the rule for two years. Several states and environmental organizations have already announced their intent to challenge the stay and any attempt by the EPA and the Corps to rescind or revise the rule. On December 11, 2018, the EPA and the Corps released the pre-publication version of the Proposed 2018 Rule concerning the redefinition of “waters of the United States.” The proposal narrows the definition of the federal waters covered under the CWA’s key permitting programs such as Section 404 dredge and fill permits, Section 402 discharge permits, and Section 311 oil spill prevention plans. The Proposed Rule works towards the administration’s larger goal of re-balancing the relationship between the federal government, tribal governments, and states by drawing boundaries between those waters subject to federal CWA requirements and those waters that states and tribal governments have flexibility to manage under their respective authorities. As written in the Proposed Rule, fewer waters would be federally regulated relative to the May 2015 rule, which would lessen CWA permitting burdens for oil and gas operations as well as reduce mitigation requirements.

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 Regulations

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 is 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. Indexing is the default methodology to change 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 in part to an inflation index and is not based on our specific costs, the indexing methodology could hamper our ability to recover cost increases.

Under the EPAct, petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct are deemed to be just and reasonable under the ICA if such rates had not been subject to complaint, protest or investigation during such 365-day period. Generally, complaints against such “grandfathered” rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPAct in either the economic circumstances of the oil pipeline or in the nature of the services provided that were a basis for the rate. EPAct places no such limit on challenges to a provision of an oil pipeline tariff rate or rules 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. In 2018, FERC issued a revised policy statement (subsequently modified in a final rule issued in July 2018) in which it held that it will no longer permit an income tax allowance to be included in cost-of-service rates for interstate pipelines structured as master limited partnerships. The FERC also indicated that it will incorporate the effects of the revised policy statement in its next review of the oil pipeline index level, which will take effect in July 2021. See Item 1A. “Risk Factors—Risks Related to Our Business—Our assets are subject to federal, state and provincial regulation. Rate regulation or a successful challenge to the rates we charge on our U.S. and Canadian pipeline systems may reduce the amount of cash we generate” for additional discussion on how our rates could be impacted by this policy change.

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial authorities. 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 U.S. trucking operations.

Table of Contents

Canada

Our trucking assets in Canada are subject to regulation by both federal and provincial transportation agencies in the provinces in which they are operated. These regulatory agencies do not set freight rates, but do establish and administer rules and regulations relating to other matters including equipment, facility inspection, reporting and safety. We are licensed to operate both intra- and inter-provincially under the direction of the National Safety Code ("NSC") that is administered by Transport Canada. Our for-hire service is primarily the transportation of crude oil, condensates and NGL. We are required under the NSC to, among other things, monitor: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailers, (v) operation and equipment safety and (vi) many other aspects of trucking operations. We are also subject to Occupational Health and Safety regulations with respect to our Canadian trucking operations.

Railcar Regulation

We own and operate a number of railcar loading and unloading facilities in the United States and Canada. In connection with these rail terminals, we own and lease a significant number of railcars. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, the OSHA, as well as other federal and state regulatory agencies and Canadian regulatory agencies for operations in Canada.

Railcar accidents involving trains carrying crude oil from North Dakota's Bakken shale formation have led to increased regulatory scrutiny. PHMSA issued a safety advisory warning that Bakken crude may be more flammable than other grades of crude oil and reinforcing the requirement to properly test, characterize, classify, and, where appropriate, sufficiently degasify hazardous materials prior to and during transportation. PHMSA also initiated "Operation Classification," a compliance initiative involving unannounced inspections and testing of crude oil samples to verify that offerors of the materials have properly classified, described and labeled the hazardous materials before transportation. In December 2015, Congress passed the Fixing America's Surface Transportation ("FAST") Act which was subsequently signed by the President. This legislation clarified the parameters around the timeline and requirements for railcars hauling crude oil in the United States. We believe our railcar fleet is in compliance in all material respects with current standards for crude oil moved by rail.

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

Cross Border Regulation

As a result of our cross border activities, including transportation and importation of crude oil, NGL and natural gas between the United States and Canada, we are subject to a variety of legal requirements pertaining to such activities including presidential permit requirements, export/import license requirements, tariffs, Canadian and U.S. customs and taxes and requirements relating to toxic substances. U.S. legal requirements relating to these activities include regulations adopted pursuant to the Short Supply Controls of the Export Administration Act ("EAA"), the North American Free Trade Agreement ("NAFTA") and the Toxic Substances Control Act ("TSCA"), as well as presidential permit requirements of the U.S. Department of State. In addition, the importation and exportation of natural gas from and to the United States and Canada is subject to regulation by U.S. Customs and Border Protection, U.S. Department of Energy and the NEB. Violations of these licensing, tariff and tax reporting requirements or failure to provide certifications relating to toxic substances could result in the imposition of significant administrative, civil and criminal penalties. Furthermore, the failure to comply with U.S. federal, state and local tax requirements, as well as Canadian federal and provincial tax requirements, could lead to the imposition of additional taxes, interest and penalties.

Table of Contents

Market Anti-Manipulation Regulation

In November 2009, the Federal Trade Commission ("FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to approximately $1.2 million per violation per day (adjusted annually for inflation). In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission ("CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of approximately $1.1 million (adjusted annually for inflation) or triple the monetary gain to the person for each violation.

Natural Gas Storage Regulation

Our natural gas storage operations are subject to regulatory oversight by numerous federal, state and local regulatory agencies, many of which are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas storage and pipeline industry, related businesses and market participants. The failure to comply with such laws and regulations can result in substantial penalties and fines.

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

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

The FERC also has authority over the siting, construction, and operation of United States pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale for resale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. The FERC's authority extends to maintenance of accounts and records, terms and conditions of service, acquisition and disposition of facilities, initiation and discontinuation of services, imposition of creditworthiness and credit support requirements applicable to customers and relationships among pipelines and storage companies and certain affiliates. Our natural gas storage entities are required by the FERC to post certain information daily regarding customer activity, capacity and volumes on their respective websites. Additionally, the FERC has jurisdiction to impose rules and regulations applicable to all natural gas market participants to ensure market transparency. FERC regulations require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC. Our natural gas storage facilities are subject to these annual reporting requirements.

Under the Energy Policy Act of 2005 ("EPAct 2005") and related regulations, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to FERC jurisdiction to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 gives the FERC civil penalty authority to impose penalties for certain violations of up to approximately $1.2 million per day for each violation (adjusted annually for inflation). FERC also has the authority to order disgorgement of profits from transactions deemed to violate the NGA and the EPAct 2005.

Table of Contents

In December 2016, PHMSA issued an interim final rule ("IFR") that establishes minimum federal standards for salt dome underground natural gas storage facilities. The IFR imposes new requirements on "downhole facilities," including wells, wellbore tubing and casings at underground natural gas storage facilities. The IFR addresses construction, maintenance, risk management and integrity management procedures for these facilities and includes registration and reporting obligations. The IFR adopts and incorporates by reference the requirements and recommendations contained in American Petroleum Institute ("API") Recommended Practice 1170. The IFR required that existing salt dome underground natural gas storage facilities meet the appropriate requirements and mandatory recommendations of API 1170 by January 18, 2018. However, PHMSA issued a partial stay of the IFR's requirements in June 2017. A final rule is expected in 2019. We do not anticipate that compliance with the final rule will have a significant adverse effect on our operations.

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

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident, natural disaster, terrorist attack, cyber event or other event. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain various types and varying levels of insurance coverage that we consider adequate under the circumstances to cover our operations and properties, and we self-insure certain risks, including gradual pollution and named windstorm. With respect to our insurance, our policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk that might occur, associated with operating pipelines, terminals and other facilities and equipment, including the potential loss of significant revenues and cash flows.

Since the terrorist attacks of September 11, 2001, the United States Government has issued numerous warnings that energy assets, including our nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. We have instituted security measures and procedures in conformity with DOT or the Transportation Safety Administration guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, there can be no assurance that these or any other security measures would protect our facilities from an attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that we maintain adequate insurance coverage, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our assets and operations. Additionally we self-insure certain risks including, gradual pollution and named windstorm. With respect to our insurance coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain other insurance programs. In addition, although we believe that we have established adequate reserves and liquidity to the extent such risks are not insured, costs incurred in excess of these reserves may be higher or we may not receive insurance proceeds in a timely manner, which may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Title to Properties and Rights-of-Way

Our real property holdings generally consist of: (i) parcels of land that we own in fee, (ii) surface leases and underground storage leases and (iii) easements, rights-of-way, permits, crossing agreements or licenses from landowners or governmental authorities permitting the use of certain lands for our operations. In all material respects, we believe we have satisfactory title or the right to use the sites upon which our significant facilities are located, subject to customary liens, restrictions or encumbrances. Except for challenges that we do not regard as material relative to our overall operations, we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses. Some of our real property rights (mainly for pipelines) may be subject to termination under agreements that provide for one or more of: periodic payments, term periods, renewal rights, abandonment of use, revocation by the licensor or grantor and possible relocation obligations.

Table of Contents

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including PMC) employed approximately 4,900 employees at December 31, 2018. Of these employees, 149 are covered by four separate collective agreements, all of which are scheduled for renegotiation in 2019. Our general partner and its affiliates consider employee relations to be good.

Summary of Tax Considerations

The following is a brief summary of certain material tax considerations of owning and disposing of common units, however, the tax consequences of ownership of common units are complex and depend in part on the owner's individual tax circumstances. This summary is based on the provisions of the Internal Revenue Code of 1986, as amended ("the Code"), U.S. Treasury regulations, administrative rulings and judicial decisions, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect. We have not sought any ruling from the Internal Revenue Service, or the IRS, with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS or a court will agree with such statements and conclusions. This summary does not address all aspects of U.S. federal income taxation or the tax considerations arising under the laws of any non-U.S., state, or local jurisdiction, or under U.S. federal estate and gift tax laws. It is the responsibility of each unitholder, either individually or through a tax advisor, to investigate the legal and tax consequences, under the laws of pertinent U.S. federal, states and localities of the unitholder's investment in us. Further, it is the responsibility of each unitholder to file all U.S. federal, state and local tax returns that may be required of the unitholder. Also see Item 1A. "Risk Factors—Tax Risks to Common Unitholders."

Partnership Status; Cash Distributions

We are treated for U.S. federal income tax purposes as a partnership based upon our meeting the "Qualifying Income Exception" imposed by Section 7704 of the Internal Revenue Code (the "Code"), which we must meet each year. The owners of our common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, subject to the Bipartisan Budget Act audit rules, we generally are not liable for U.S. federal income taxes, and a common unitholder is required to report on the unitholder's federal income tax return the unitholder's share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and to the extent that, they exceed the tax basis in the common units held. In certain cases, we are subject to, or have paid Canadian income and withholding taxes, including with respect to intercompany interest payments and dividend payments. Unitholders may be eligible for foreign tax credits with respect to allocable Canadian withholding and income taxes paid.

Partnership Allocations

In general, our income and loss is allocated to the general partner and the unitholders for each taxable year in accordance with their respective percentage interests in the Partnership, as determined annually and prorated on a monthly basis and subsequently apportioned among the general partner and the unitholders of record as of the opening of the first business day of the month to which they relate, even though unitholders may dispose of their units during the month in question. A unitholder who disposes of common units prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deduction attributable to the month of disposition (and any other month during the quarter to which such cash distribution relates and the holder held common units on the first day of such month) but will not be entitled to receive a cash distribution for that period. In determining a unitholder's U.S. federal income tax liability, the unitholder is required to take into account the unitholder's share of income generated by us for each taxable year of the Partnership ending with or within the unitholder's taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder's share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us.

Basis of Common Units

A unitholder's initial tax basis for a common unit is generally the amount paid for the common unit and the unitholder's share of our nonrecourse liabilities (or liabilities for which no partner bears the economic risk of loss). A unitholder's basis is generally increased by the unitholder's share of our income and by any increases in the unitholder's share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by the unitholder's share of our losses, the amount of all distributions made to the unitholder (including deemed distributions due to a decrease in the unitholder's share of our nonrecourse liabilities) and the amount of any excess business interest allocated to the unitholder.

Limitations on Deductibility of Partnership Losses

The deduction by a unitholder of that unitholder's allocable share of our losses will be limited to the amount of that unitholder's tax basis in his or her common units and, in the case of an individual unitholder or a corporate unitholder who is subject to the "at risk" rules (generally, certain closely-held corporations), to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than the unitholder's tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause the unitholder's at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such unitholder's tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain could no longer be used.

In addition to the basis and at-risk limitations described above, a passive activity loss limitation generally limits the deductibility of losses incurred by individuals, estates, trusts, some closely-held corporations and personal service corporations from "passive activities" (generally, trade or business activities in which the taxpayer does not materially participate). The passive loss limitations are applied separately with respect to each publicly-traded partnership. Consequently, any passive losses we generate will be available to offset only passive income generated by us, and will not be available to offset income from other passive activities or investments, including investments in other publicly traded partnerships or salary, active business or other income. Passive losses that exceed a unitholder's share of passive income we generate may be deducted in full when the unitholder disposes of all of its units in a fully taxable transaction with an unrelated party. The passive activity loss rules are generally applied after other applicable limitations on deductions, including the at risk and basis limitations.

For taxpayers other than corporations in taxable years beginning after December 31, 2017, and before January 1, 2026, an "excess business loss" limitation further limits the deductibility of losses by such taxpayers. An excess business loss is the excess (if any) of a taxpayer's aggregate deductions for the taxable year that are attributable to the trades or businesses of such taxpayer (determined without regard to the excess business loss limitation) over the aggregate gross income or gain of such taxpayer for the taxable year that is attributable to such trades or businesses plus a threshold amount. The threshold amount is equal to $250,000, or $500,000 for taxpayers filing a joint return. Disallowed excess business losses are treated as a net operating loss carryover to the following tax year. Any losses we generate that are allocated to a unitholder and not otherwise limited by the basis, at risk, or passive loss limitations will be included in the determination of such unitholder's aggregate trade or business deductions. Consequently, any losses we generate that are not otherwise limited will only be available to offset a unitholder's other trade or business income plus an amount of non-trade or business income equal to the applicable threshold amount. Thus, except to the extent of the threshold amount, our losses that are not otherwise limited may not offset a unitholder's non-trade or business income (such as salaries, fees, interest, dividends and capital gains). This excess business loss limitation will be applied after the passive activity loss limitation.

Limitations on Interest Deductions

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, our deduction for this "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. This limitation is first applied at the partnership level and any deduction for business interest is taken into account in determining our non-separately stated taxable income or loss. Then, in applying this business interest limitation at the partner level, the adjusted taxable income of each of our unitholders is determined without regard to such unitholder's distributive share of any of our items of income, gain, deduction, or loss and is increased by such unitholder's distributive share of our excess taxable income, which is generally equal to the excess of 30% of our adjusted taxable income over the amount of our deduction for business interest for a taxable year.

To the extent our deduction for business interest is not limited, we will allocate the full amount of our deduction for business interest among our unitholders in accordance with their percentage interests in us. To the extent our deduction for business interest is limited, the amount of any disallowed deduction for business interest will also be allocated to each unitholder in accordance with their percentage interest in us, but such amount of "excess business interest" will not be currently deductible. Subject to certain limitations and adjustments to a unitholder's basis in its common units, this excess business interest may be carried forward and deducted by a unitholder in a future taxable year. Further, a unitholder's basis in his or her common units will generally be increased by the amount of any excess business interest upon a disposition of such common units.

Section 754 Election

We have made the election provided for by Section 754 of the Code, which will generally result in a unitholder being allocated income and deductions calculated by reference to the portion of the unitholder's purchase price attributable to each asset of the Partnership.

Disposition of Common Units

A unitholder who sells common units will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis of those common units (taking into account any basis adjustments attributable to previously disallowed interest deductions). A unitholder may not be able to trace basis to particular common units for this purpose. Thus, distributions of cash from us to a unitholder in excess of the income allocated to the unitholder will, in effect, become taxable income if the unitholder sells the common units at a price greater than the unitholder's adjusted tax basis even if the price is less than the unitholder's original cost. Moreover, a portion of the amount realized (whether or not representing gain) will be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we conduct business or own property. We own property and conduct business in most states in the United States as well as several provinces in Canada. A unitholder may also be required to file state income tax returns and to pay taxes in various states, even if they do not live in those jurisdictions. As our entire Canadian source income passes through Canadian taxable entities, our unitholders do not have a separate Canadian tax filing obligation as it relates to this income. Unitholders who are not resident in the United States may have additional tax reporting and payment requirements.

A unitholder may be subject to interest and penalties for failure to comply with such requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be more or less than a particular unitholder's income tax liability owed to a particular state, may not relieve the unitholder from the obligation to file an income tax return in that state. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Ownership of Common Units by Tax-Exempt Organizations and Certain Other Investors

An investment in common units by tax-exempt organizations (including Individual Retirement Accounts ("IRAs") and other retirement plans) and non-U.S. persons raises issues unique to such persons. Virtually all of our income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. A unitholder who is a nonresident alien, non-U.S. corporation or other non-U.S. person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder's share of our taxable income and on gain realized from the sale or disposition of common units to the extent the gain is effectively connected with a U.S. trade or business of the non-U.S. unitholder.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferees but were not withheld. Because the "amount realized" includes a partner's share of the partnership's liabilities, 10% of the amount realized could exceed the total cash purchase price for the common units. For this and other reasons, the IRS has suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships, pending promulgation of regulations that address the amount to be withheld, the reporting necessary to determine such amount and the appropriate party to withhold such amounts, but it is not clear if or when such regulations will be issued. Finally, distributions to non-U.S. unitholders are generally subject to federal income tax withholding at the highest applicable rate.

Table of Contents

Audit Procedures

Publicly-traded partnerships are treated as entities separate from their owners for purposes of federal income tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings for each of the partners. Pursuant to the Bipartisan Budget Act of 2015, for taxable years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, unless we elect to have our general partner, unitholders and former unitholders take any audit adjustment into account in accordance with their interests in us during the taxable year under audit. Similarly, for such taxable years, if the IRS makes audit adjustments to income tax returns filed by an entity in which we are a member or partner, it may assess and collect any taxes (including penalties and interest) resulting from such audit adjustment directly from such entity.

Available Information

We make available, free of charge on our Internet website at http://www.plainsallamerican.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission ("SEC"). The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov.

Item 1A. Risk Factors

Risks Related to Our Business

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

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

During the latter half of 2014 and continuing into 2016, benchmark crude oil prices declined significantly; as a result, many of the companies that produce oil and gas significantly reduced capital expenditures. Such reduced expenditure levels, coupled with high decline rates for many horizontal wells in the shale resource plays, led to production declines in many areas in the Lower 48 United States (excluding Gulf of Mexico production). After recovering in late 2017 through mid-2018, benchmark crude oil prices experienced volatility in the second half of 2018. If producers again reduce drilling activity in response to future declines in benchmark crude oil prices, it could adversely impact production. Other factors that could adversely impact production include reduced capital market access, increased capital raising costs for producers or adverse governmental or regulatory action. In turn, such developments could lead to reduced throughput on our pipelines and at our other facilities, which, depending on the level of production declines, could have a material adverse effect on our business.

Also, except with respect to some of our recently constructed pipeline assets, third-party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues.

To maintain the volumes of crude oil we purchase in connection with our operations, we must continue to contract for new supplies of crude oil to offset volumes lost because of reduced drilling activity by producers, natural declines in crude oil production from depleting wells or volumes lost to competitors. If production declines, competitors with under-utilized assets could impair our ability to secure additional supplies of crude oil.

Table of Contents

Our profitability can be negatively affected by a variety of factors stemming from competition in our industry, including risks associated with the general capacity overbuild of midstream energy infrastructure in some of the areas where we operate.

We face competition in all aspects of our business and can give no assurances that we will be able to compete effectively against our competitors. In general, competition comes from a wide variety of participants in a wide variety of contexts, including new entrants and existing participants and in connection with day-to-day business, expansion capital projects, acquisitions and joint venture activities. Some of our competitors have capital resources many times greater than ours and control greater supplies of crude oil, natural gas or NGL.

A significant driver of competition in some of the markets where we operate (including, for example, the Eagle Ford, Permian Basin, and Rockies/Bakken areas) stems from the rapid development of new midstream energy infrastructure capacity that was driven by the combination of (i) significant increases in oil and gas production and development in the applicable production areas, both actual and anticipated, (ii) relatively low barriers to entry and (iii) generally widespread access to relatively low cost capital. While this environment presented opportunities for us, many of these areas have become, or in the future may become, overbuilt, resulting in an excess of midstream energy infrastructure capacity. For example, in the past eighteen months, several potential new pipeline projects have been announced or are currently under construction, and such projects may result in excess takeaway capacity in certain areas where we operate. In addition, as an established participant in some markets, we also face competition from aggressive new entrants to the market who are willing to provide services at a lower rate of return in order to establish relationships and gain a foothold in the market. We also face competition for incremental volumes from shippers on third-party pipelines who overcommitted relative to their actual production or committed supplies and are now purchasing barrels on the open market and shipping them on such third-party pipelines in order to satisfy their minimum commitment levels. In addition, our Supply and Logistics segment is a customer of our Transportation and Facilities segments (See Note 20 to our Consolidated Financial Statements for a discussion of our operating segments). Competition that impacts our Supply and Logistics activities could result in a reduction in the use of our Transportation and Facilities assets by our Supply and Logistics segment. All of these competitive effects put downward pressure on our throughput and margins and, together with other adverse competitive effects, could have a significant adverse impact on our financial position, cash flows and ability to pay or increase distributions to our unitholders.

With respect to our crude oil activities, our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, refiners, private equity-backed entities, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. We compete against these companies on the basis of many factors, including geographic proximity to production areas, market access, rates, terms of service, connection costs and other factors.

With respect to our natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. 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.

With regard to our NGL operations, we compete with large oil, natural gas and natural gas liquids companies that may, relative to us, have greater financial resources and access to supplies of natural gas and NGL. The principal elements of competition are rates, processing fees, geographic proximity to the natural gas or NGL mix, available processing and fractionation capacity, transportation alternatives and their associated costs, and access to end-user markets.

Fluctuations in supply and demand, which can be caused by a variety of factors outside of our control, can negatively affect our operating results.

Supply and demand for crude oil and other hydrocarbon products we handle is dependent upon a variety of factors, including price, the impact of future economic conditions, fuel conservation measures, alternative fuel adoption, governmental regulation, including climate change regulations, and technological advances in fuel economy and energy generation devices. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could increase the cost of consuming crude oil and other hydrocarbon products, thereby causing a reduction in the demand for such products. Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets. The supply of crude oil depends on a variety of global political and economic factors, including the reliance of foreign governments on petroleum revenues. Excess global supply of crude oil may negatively impact our operating results by decreasing the price of crude oil and making production and transportation less profitable in areas we service.

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

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

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

A natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks), process safety failure or other event, including pipeline or facility accidents and attacks on our electronic and computer systems, could interrupt our operations and/or result in severe personal injury, property damage and environmental damage, which could have a material adverse effect on our financial position, results of operations and cash flows.

Some of our operations involve risks of personal injury, property damage and environmental damage that could curtail our operations and otherwise materially adversely affect our cash flow. Virtually all of our operations are exposed to potential natural disasters or other natural events, including hurricanes, tornadoes, storms, floods, earthquakes, shifting soil and/or landslides. The location of some of our assets and our customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk. Our facilities and operations are also vulnerable to accidents caused by process safety failures, equipment failures or human error. In addition, since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be future targets of terrorist organizations. Terrorists may target our physical facilities and hackers may attack our electronic and computer systems.

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

We may also suffer damage (including reputational damage) as a result of a disaster, accident, catastrophe, terrorist attack or other such event. The occurrence of such an event, or a series of such events, especially if one or more of them occurs in a highly populated or sensitive area, could negatively impact public perception of our operations and/or make it more difficult for us to obtain the approvals, permits, licenses or real property interests we need in order to operate our assets or complete planned growth projects.

Cybersecurity breaches and other disruptions could compromise our information and operations, and expose us to liability, which would cause our business and reputation to suffer.

We are reliant on the continuous and uninterrupted operation of our information technology systems. User access of our sites and information technology systems are critical elements to our operations, as is cloud security and protection against cyber security incidents. In the ordinary course of our business, we collect and store sensitive data in our data centers and on our networks, including intellectual property, proprietary business information, information regarding our customers, suppliers, royalty owners and business partners, and personally identifiable information of our employees. The secure processing, maintenance and transmission of this information is critical to our operations and business strategy. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties for divulging shipper information, disruption of our operations, damage to our reputation, and loss of confidence in our services, which could adversely affect our business.

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-to-day operations. Potential risks to our IT systems could include unauthorized attempts to extract business sensitive, confidential or personal information, denial of access extortion, corruption of information or disruption of business processes, or by inadvertent or intentional actions by our employees or vendors. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, safety incidents, damage to the environment, remediation costs, potential liability, regulatory enforcement, violation of privacy or securities laws and regulations or the loss of contracts, any of which could have a material adverse effect on our operations, financial position and results of operations.

We may face opposition to the development or operation of our pipelines and facilities from various groups.

We may face opposition to the development or operation of our pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or other facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities or energy infrastructure related projects, and consequently could both indirectly affect demand for our services and directly affect our ability to fund construction or other capital projects.

The results of our Supply and Logistics segment are influenced by the overall forward market for crude oil and NGL, and certain market structures, the absence of pricing volatility and other market factors may adversely impact our results.

Results from our Supply and Logistics segment are dependent on a variety of factors affecting the markets for crude oil and NGL, including regional and international supply and demand imbalances, takeaway availability and constraints, transportation costs and the overall forward market for crude oil. Periods when differentials are wide or when there is volatility in the forward market structure are generally more favorable for our Supply and Logistics segment. During periods where the infrastructure is over-built and/or there is a lack of volatility in the pricing structure our results may be negatively impacted. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage agreements, these periods may have either an adverse or beneficial effect on our aggregate segment results. In the past, the results from our Supply and Logistics segment have varied significantly based on market conditions and this segment may continue to experience highly variable results as a result of future changes to the markets for crude oil and NGL.

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

We believe that, because of our strategic asset base and complementary business model, we will continue to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil, NGL and natural gas markets. The extent to which we are able to capture that benefit, however, is subject to numerous risks and uncertainties, including whether we will be able to maintain an attractive credit rating and continue to receive open credit from our suppliers and trade counterparties. Our senior unsecured debt is currently rated as “investment grade” by Standard & Poor’s and Fitch Ratings Inc. In August 2017, Moody’s Investors Service downgraded its rating of our senior unsecured debt to a level below investment grade. A further downgrade by Standard & Poor’s or Fitch Ratings, Inc. to a level below our current ratings levels assigned by such rating agencies could increase our borrowing costs, reduce our borrowing capacity and cause our counterparties to reduce the amount of open credit we receive from them. This could negatively impact our ability to capitalize on market opportunities. For example, our ability to utilize our crude oil storage capacity for merchant activities to capture contango market opportunities is dependent upon having adequate credit facilities, both in terms of the total amount of credit facilities and the cost of such credit facilities, which enables us to finance the storage of the crude oil from the time we complete the purchase of the crude oil until the time we complete the sale of the crude oil. Loss of our remaining investment grade credit ratings could also adversely impact our cash flows, our ability to make distributions at our current levels and the value of our outstanding equity and debt securities.

If we make acquisitions that fail to perform as anticipated, our future growth may be limited.

In evaluating acquisitions, we generally prepare one or more financial cases based on a number of business, industry, economic, legal, regulatory, and other assumptions applicable to the proposed transaction. Although we expect a reasonable basis will exist for those assumptions, the assumptions will generally involve current estimates of future conditions. Realization of many of the assumptions will be beyond our control. Moreover, the uncertainty and risk of inaccuracy associated with any financial projection will increase with the length of the forecasted period. Some acquisitions may not be accretive in the near term, and will be accretive in the long term only if we are able to timely and effectively integrate the underlying assets and such assets perform at or near the levels anticipated in our acquisition projections.

Acquisitions and joint ventures involve risks that may adversely affect our business.

Any acquisition involves potential risks, including:

- performance from the acquired businesses or assets that is below the forecasts we used in evaluating the acquisition;
- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets for which we are either not fully insured or indemnified, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;
- risks associated with operating in lines of business that are distinct and separate from our historical operations;
- customer or key employee loss from the acquired businesses; and

Table of Contents

- the diversion of management's attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to pay distributions to our partners or meet our debt service requirements.

We are also involved in many strategic joint ventures. We may not always be in complete alignment with our joint venture counterparties - we may have differing strategic or commercial objectives or we may disagree on governance matters with respect to the joint venture entity. When we enter into joint ventures we may be subject to the risk that our counterparties do not fund their obligations. In some joint ventures we may not be responsible for construction or operation of such projects and will rely on our joint venture counterparties for such services. Joint ventures may also require us to expend additional internal resources that could otherwise be directed to other projects. If we are unable to successfully execute and manage our existing and proposed joint venture projects, it could adversely impact our financial and operating results.

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

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

- As these projects are undertaken, required approvals, permits and licenses may not be obtained, may be delayed, may be obtained with conditions that materially alter the expected return associated with the underlying projects or may be granted and then subsequently withdrawn;
- We may face opposition to our planned growth projects from environmental groups, landowners, local groups and other advocates, including lawsuits or other actions designed to disrupt or delay our planned projects;
- We may not be able to obtain, or we may be significantly delayed in obtaining, all of the rights of way or other real property interests we need to complete such projects, or the costs we incur in order to obtain such rights of way or other interests may be greater than we anticipated;
- Despite the fact that we will expend significant amounts of capital during the construction phase of these projects, revenues associated with these organic growth projects will not materialize until the projects have been completed and placed into commercial service, and the amount of revenue generated from these projects could be significantly lower than anticipated for a variety of reasons;
- We may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes;
- Due to unavailability or costs of materials, supplies, power, labor or equipment, including increased costs associated with any import duties or requirements to source certain supplies or materials from U.S. suppliers or manufacturers, the cost of completing these projects could turn out to be significantly higher than we budgeted and the time it takes to complete construction of these projects and place them into commercial service could be significantly longer than planned; and
- The completion or success of our projects may depend on the completion or success of third-party facilities over which we have no control.

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

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

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

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

We are exposed to the credit risk of our customers and other counterparties we transact within the ordinary course of our business activities.

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

We have a number of minimum volume commitment contracts that support pipelines in our Transportation segment. In addition, certain of the pipelines in which we own a joint venture interest have minimum volume commitment contracts. Pursuant to such contracts, shippers are obligated to pay for a minimum volume of transportation service regardless of whether such volume is actually shipped (typically referred to as a deficiency payment), subject to the receipt of credits that typically expire if not used by a certain date. While such contracts provide greater revenue certainty, if the applicable shipper fails to transport the minimum required volume and is required to make a deficiency payment, under applicable accounting rules, the revenue associated with such deficiency payment may not be recognized until the applicable transportation credit has expired or has been used. Deferred revenue associated with non-performance by shippers under minimum volume contracts could be significant and could adversely affect our profitability and earnings.

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

Further, to the extent one or more of our major customers experiences financial distress or commences bankruptcy proceedings, contracts with such customers (including contracts that are supported by acreage dedications) may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Any such renegotiation or rejection could have an adverse effect on our revenue and cash flows and our ability to make cash distributions to our unitholders.

We have also undertaken numerous projects that require cooperation with and performance by joint venture co-owners. In addition, in connection with various acquisition, divestiture, joint venture and other transactions, we often receive indemnifications from various parties for certain risks or liabilities. Nonperformance by any of these parties could result in increased costs or other adverse consequences that could decrease our earnings and returns.

We also rely to a significant degree on the banks that lend to us under our revolving credit facility for financial liquidity, and any failure of those banks to perform on their obligations to us could significantly impair our liquidity.

Furthermore, nonpayment by the counterparties to our interest rate, commodity and/or foreign currency derivatives could expose us to additional interest rate, commodity price and/or foreign currency risk.

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

Generally, it is our policy to establish a margin for crude oil or other products we purchase by selling such products for physical delivery to third-party users, or by entering into a future delivery obligation under derivative contracts. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other hand. Our policy is not to acquire and hold physical inventory or derivative products for the purpose of speculating on commodity price changes. These policies and practices cannot, however, eliminate all risks. For example, any event that disrupts our anticipated physical supply of crude oil or other products could expose us to risk of loss resulting from price changes. We are also exposed to basis risk when crude oil or other products are purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including risks on certain of our inventory, such as linefill, which must be maintained in order to transport crude oil on our pipelines. In an effort to maintain a balanced position, specifically authorized personnel can purchase or sell crude oil, refined products and NGL, up to predefined limits and authorizations. Although this activity is monitored independently by our risk management function, it exposes us to commodity price risks within these limits.

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

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. The current laws and regulations affecting our business are subject to change and in the future we may be subject to additional laws and regulations, which could adversely impact our business.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil, NGL and refined products, as well as our operations involving the storage of natural gas, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment and wildlife, operational safety, climate change and related matters. Compliance with all of these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases (such as carbon dioxide and methane), including cap and trade programs, could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. In addition, with respect to our railcar operations, the adoption of new regulations designed to enhance the overall safety of crude oil and natural gas liquids transportation by rail could result in increased operating costs and potentially involve substantial capital expenditures. Also, new or additional regulations, new interpretations of existing requirements or changes in our operations could trigger new permitting requirements applicable to our operations, which could result in increased costs or delays of, or denial of rights to conduct, our development programs. The failure to comply with any such laws and regulations could result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, the issuance of injunctions that may subject us to additional operational requirements and constraints, or claims of damages to property or persons resulting from our operations. In addition, criminal violations of certain environmental laws, or in some cases even the allegation of criminal violations, may result in the temporary suspension or outright debarment from participating in government contracts. The laws and regulations applicable to our operations are subject to change and interpretation by the relevant governmental agency, including the possibility that exemptions we currently qualify for may be modified or changed in ways that require us to incur significant additional compliance costs. Our business and operations may also become subject to additional laws or regulations. Any new laws or regulations, or changes to or interpretations of existing laws or regulations, adverse to us could have a material adverse effect on our operations, revenues, expenses and profitability.

We have a history of incremental additions to the miles of pipelines we own, both through acquisitions and expansion capital projects. We have also increased our terminal and storage capacity and operate several facilities on or near navigable waters and domestic water supplies. Although we have implemented programs intended to maintain the integrity of our assets (discussed below), as we acquire additional assets we are at risk for an increase in the number of releases of liquid hydrocarbons into the environment. These releases expose us to potentially substantial expense, including clean-up and remediation costs, fines and penalties, and third party claims for personal injury or property damage related to past or future releases. Some of these expenses could increase by amounts disproportionately higher than the relative increase in pipeline mileage and the increase in revenues associated therewith. Our refined products terminal assets are also subject to significant compliance costs and liabilities. In addition, because of the increased volatility of refined products and their tendency to migrate farther and faster than crude oil when released, releases of refined products into the environment can have a more significant impact than crude oil and require significantly higher expenditures to respond and remediate. The incurrence of such expenses not covered by insurance, indemnity or reserves could materially adversely affect our results of operations.

We currently devote substantial resources to comply with DOT-mandated pipeline integrity rules. The DOT regulations include requirements for the establishment of pipeline integrity management programs and for protection of “high consequence areas” where a pipeline leak or rupture could produce significant adverse consequences. Pipeline safety regulations are revised frequently. For example, PHMSA is expected to publish finalized regulations in the first half of 2019 for hazardous liquid pipelines which will significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, leak detection and repairs) regardless of proximity to a high consequence area. The final rule will also impose new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. The adoption of new regulations requiring more comprehensive or stringent safety standards could require us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant.

Although we continue to focus on pipeline and facility integrity management as a primary operational emphasis, doing so requires substantial time and resources and cannot eliminate all risk of releases. We have an internal review process pursuant to which we examine various aspects of our pipeline and gathering systems that are not currently subject to the DOT pipeline integrity management mandate. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from regulatory agency enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to enhance the integrity of and upgrade our pipeline systems to maintain environmental compliance and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures but any such expenditures could be significant. See "Environmental — General" in Note 18 to our Consolidated Financial Statements. In addition, despite our pipeline and facility integrity management efforts, we can provide no assurance that our pipelines and facilities will not experience leaks or releases or that we will be able to fully comply with all of the federal, state and local laws and regulations applicable to the operation of our pipelines or facilities; any such leaks or releases could be material and could have a significant adverse impact on our reputation, financial position, cash flows and ability to pay or increase distributions to our unitholders.

Our assets are subject to federal, state and provincial regulation. Rate regulation or a successful challenge to the rates we charge on our U.S. and Canadian pipeline systems may reduce the amount of cash we generate.

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

For our U.S. interstate common carrier liquids pipelines subject to FERC regulation under the ICA, shippers may protest our pipeline tariff filings or file complaints against our existing rates or complaints alleging that we are engaging in discriminating behavior. The FERC can also investigate on its own initiative. Under certain circumstances, the FERC could limit our ability to set rates based on our costs, or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint. Natural gas storage facilities are subject to regulation by the FERC, the DOT, and certain state agencies.

In March 2018, FERC issued a revised policy statement (subsequently modified in a final rule issued in July 2018) in which it held that it will no longer permit an income tax allowance to be included in cost-of-service rates for interstate pipelines structured as master limited partnerships. The FERC also indicated that it will incorporate the effects of the revised policy statement in its next review of the oil pipeline index level, which will take effect in July 2021. We do not have cost-of-service rates that would be impacted by this policy change; our FERC regulated tariffs are either grandfathered or based on negotiated rates. However, depending on how the FERC incorporates its most recent tax policy statement into its next index review, the policy could potentially have a negative impact on the FERC adder to the PPI-FG Index, which in turn could have a negative effect on our ability to increase our index-based rates. The policy could impact future (i.e., July 2021 and later) tariff escalations on our FERC regulated pipelines, as well as some of our state-regulated pipelines that have negotiated rates with escalations tied to the FERC Index.

In addition, we routinely monitor the public filings and proceedings of other parties with the FERC and other regulatory agencies in an effort to identify issues that could potentially impact our business. Under certain circumstances we may choose to intervene in such third-party proceedings in order to express our support for, or our opposition to, various issues raised by the parties to such proceedings. For example, if we believe that a petition filed with, or order issued by, the FERC is improper, overbroad other otherwise flawed, we may attempt to intervene in such proceedings for the purpose of protesting such petition or order and requesting appropriate action such as a clarification, rehearing or other remedy. Despite such efforts, we can provide no assurance that the FERC and other agencies that regulate our business will not issue future orders or declarations that increase our costs or otherwise adversely affect our operations.

Table of Contents

The FERC issued a Notice of Inquiry on April 19, 2018 (Certificate Policy Statement NOI), thereby initiating a review of its policies on certification of natural gas pipelines and storage facilities, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline and storage projects and expansions. Comments on the Certificate Policy Statement NOI were due on July 25, 2018, and we are unable to predict what, if any, changes may be proposed as a result of the NOI that will affect our natural gas storage business or when such proposals, if any, might become effective.

Our Canadian pipelines are subject to regulation by the NEB and by provincial authorities. Under the National Energy Board Act, the NEB could investigate the tariff rates or the terms and conditions of service relating to a jurisdictional pipeline on its own initiative upon the filing of a toll or tariff application, or upon the filing of a written complaint. If the NEB found the rates or terms of service relating to such pipeline to be unjust or unreasonable or unjustly discriminatory, the NEB could require us to change our rates, provide access to other shippers, or change our terms of service. A provincial authority could, on the application of a shipper or other interested party, investigate the tariff rates or our terms and conditions of service relating to our provincially-regulated proprietary pipelines. If it found our rates or terms of service to be contrary to statutory requirements, it could impose conditions it considers appropriate. A provincial authority could declare a pipeline to be a common carrier pipeline, and require us to change our rates, provide access to other shippers, or otherwise alter our terms of service. Any reduction in our tariff rates would result in lower revenue and cash flows.

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

Our cross border activities subject us to regulatory matters, including import and export licenses, tariffs, Canadian and U.S. customs and tax issues and toxic substance certifications. Such regulations include the Short Supply Controls of the EAA, the NAFTA and the TSCA. Violations of these licensing, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties.

Our purchases and sales of crude oil, natural gas and NGL, and hedging activities, expose us to potential regulatory risks.

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

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), enacted on July 21, 2010, established federal oversight and regulation of derivative markets and entities, such as us, that participate in those markets. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the

Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

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

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing, and the associated rules require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption from such requirements. We do not utilize credit default swaps and we qualify for, and expect to continue to qualify for, the end-user exception from the mandatory clearing requirements for swaps

Table of Contents

entered into to hedge our interest rate risks. Should the CFTC designate commodity derivatives for mandatory clearing, we would expect to qualify for an end-user exception from the mandatory clearing requirements for swaps entered into to hedge our commodity price risk. However, the majority of our financial derivative transactions used for hedging commodity price risks are currently executed and cleared over exchanges that require the posting of margin or letters of credit based on initial and variation margin requirements. Pursuant to the Dodd Frank Act, however, the CFTC or federal banking regulators may require the posting of collateral with respect to uncleared interest rate and commodity derivative transactions.

Certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we qualify for the end-user exception from margin requirements for swaps entered into to hedge commercial risks, if any of our swaps do not qualify for the commercial end-user exception, or if we are otherwise required to post additional cash margin or collateral it could reduce our ability to execute hedges necessary to reduce commodity price exposures and protect cash flows. Posting of additional cash margin or collateral could affect our liquidity (defined as unrestricted cash on hand plus available capacity under our credit facilities) and reduce our ability to use cash for capital expenditures or other partnership purposes.

Even if we ourselves are not required to post additional cash margin or collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with other new requirements under the Dodd-Frank Act and related rules. The costs of such compliance may be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions or reducing our profitability. In addition, implementation of the Dodd-Frank Act and related rules and regulations could reduce the overall liquidity and depth of the markets for financial and other derivatives we utilize in connection with our business, which could expose us to additional risks or limit the opportunities we are able to capture by limiting the extent to which we are able to execute our hedging strategies.

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

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

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from unconventional geological formations. Recent advances in hydraulic fracturing techniques have resulted in significant increases in crude oil and natural gas production in many basins in the United States and Canada. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, and it is typically regulated by state and provincial oil and gas commissions. We do not perform hydraulic fracturing, but many of the producers using our pipelines do. Hydraulic fracturing has been subject to increased scrutiny due to public concerns that it could result in contamination of drinking water supplies, and there have been a variety of legislative and regulatory proposals to prohibit, restrict, or more closely regulate various forms of hydraulic fracturing. Any legislation or regulatory initiatives that curtail hydraulic fracturing or otherwise limit producers' ability to drill or complete wells could reduce the production of crude oil and natural gas in the United States or Canada, and could thereby reduce demand for our transportation, terminalling and storage services as well as our supply and logistics services.

Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for crude oil and natural gas, while potential physical effects of climate change could disrupt crude oil production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act to reduce GHG emissions. For example, in June 2016, the EPA finalized new regulations, known as Subpart OOOOa, that set emissions standards for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. However, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing.

Table of Contents

While Congress has from time to time considered legislation to reduce emissions of GHGs, no significant legislation to reduce GHG emissions has been adopted at the federal level. In the absence of federal climate legislation, a number of state and regional GHG restrictions have emerged. Analogous regulations are or may be implemented in Canada. Any future laws and regulations that limit emissions of GHGs could adversely affect demand for oil and natural gas that operators, some of whom are our customers, produce and could thereby reduce demand for our midstream services.

Moreover, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain sources of capital restricting or eliminating their investment in oil and natural gas activities. Additionally, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or restrict more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could make it more difficult for operators to engage in exploration and production activities, ultimately reducing demand for our services. Finally, many scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events; if any such effects were to occur, they have the potential to cause physical damage to our assets and thus could have an adverse effect on our financial condition and operations.

We may in the future encounter increased costs related to, and lack of availability of, insurance.

Over the last several years, as the scale and scope of our business activities has expanded, the breadth and depth of available insurance markets has contracted. As a result of these factors and other market conditions, as well as the fact that we have experienced several incidents over the last 3 to 5 years, premiums and deductibles for certain insurance policies have increased substantially. Accordingly, we can give no assurance that we will be able to maintain adequate insurance in the future at rates or on other terms we consider commercially reasonable. In addition, although we believe that we currently maintain adequate insurance coverage, insurance will not cover many types of interruptions or events that might occur and will not cover all risks associated with our operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. The occurrence of a significant event, the consequences of which are either not covered by insurance or not fully insured, or a significant delay in the payment of a major insurance claim, could materially and adversely affect our financial position, results of operations and cash flows.

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

As of December 31, 2018, the face value of our consolidated debt outstanding was approximately $9.3 billion, consisting of approximately $9.2 billion face value of long-term debt (including senior notes and long-term commercial paper and credit facility borrowings) and approximately $0.1 billion of short-term borrowings. As of December 31, 2018, we had approximately $2.9 billion of liquidity available, including cash and cash equivalents and available borrowing capacity under our senior unsecured revolving credit facility and our senior secured hedged inventory facility, subject to continued covenant compliance. Lower Adjusted EBITDA could increase our leverage ratios and effectively reduce our ability to incur additional indebtedness.

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

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

- credit rating agencies may view our debt level negatively;
- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt; and
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Table of Contents

Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things, incur indebtedness if certain financial ratios are not maintained, grant liens, engage in transactions with affiliates, enter into sale-leaseback transactions, and sell substantially all of our assets or enter into a merger or consolidation. Our credit facilities treat a change of control as an event of default and also requires us to maintain a certain debt coverage ratio. Our senior notes do not restrict distributions to unitholders, but a default under our credit agreements will be treated as a default under the senior notes. Please read Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreements, Commercial Paper Program and Indentures."

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, our operating and financial performance, the amount of our current maturities and debt maturing in the next several years, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, be unable to receive open credit from our suppliers and trade counterparties, be unable to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market or suffer a reduction in the market price of our common units. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we might be forced to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities, or sell assets. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

Increases in interest rates could adversely affect our business and the trading price of our units.

As of December 31, 2018, the face value of our consolidated debt was approximately $9.3 billion, of which approximately $9.1 billion was at fixed interest rates and approximately $0.2 billion was at variable interest rates. We are exposed to market risk due to the short-term nature of our commercial paper borrowings and the floating interest rates on our credit facilities. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, increases in interest rates could adversely affect our Supply and Logistics segment results by increasing interest costs associated with the storage of hedged crude oil and NGL inventory. Further, the trading price of our common units may be sensitive to changes in interest rates and any rise in interest rates could adversely impact such trading price.

Changes in currency exchange rates could adversely affect our operating results.

Because we are a U.S. dollar reporting company and also conduct operations in Canada, we are exposed to currency fluctuations and exchange rate risks that may adversely affect the U.S. dollar value of our earnings, cash flow and partners' capital under applicable accounting rules. For example, as the U.S. dollar appreciates against the Canadian dollar, the U.S. dollar value of our Canadian dollar denominated earnings is reduced for U.S. reporting purposes.

Our business requires the retention and recruitment of a skilled workforce, and difficulties recruiting and retaining our workforce could result in a failure to implement our business plans.

Our operations and management require the retention and recruitment of a skilled workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry for this skilled workforce. If we are unable to (i) retain current employees; and/or (ii) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Table of Contents

An impairment of long-term assets could reduce our earnings.

At December 31, 2018, we had approximately $14.8 billion of net property and equipment, $916 million of linefill and base gas, $2.5 billion of goodwill, $2.7 billion of investments accounted for under the equity method of accounting and $772 million of net intangible assets capitalized on our balance sheet. GAAP requires an assessment for impairment on an annual basis or in certain circumstances, including when there is an indication that the carrying value of property and equipment may not be recoverable or a determination that it is more likely than not that a reporting unit's carrying value is in excess of the reporting unit's fair value. If we were to determine that any of our property and equipment, linefill and base gas, goodwill, intangibles or equity method investments was impaired, we could be required to take an immediate charge to earnings, which could adversely impact our operating results, with a corresponding reduction of partners' capital and increase in balance sheet leverage as measured by debt-to-total capitalization. See Note 6 to our Consolidated Financial Statements for additional information regarding impairments.

Rail and marine transportation of crude oil have inherent operating risks.

Our supply and logistics operations include purchasing crude oil that is carried on railcars, tankers or barges. Such cargos are at risk of being damaged or lost because of events such as derailment, marine disaster, inclement weather, mechanical failures, grounding or collision, fire, explosion, environmental accidents, piracy, terrorism and political instability. Such occurrences could result in death or injury to persons, loss of property or environmental damage, delays in the delivery of cargo, loss of revenues, termination of contracts, governmental fines, penalties or restrictions on conducting business, higher insurance rates and damage to our reputation and customer relationships generally. Although certain of these risks may be covered under our insurance program, any of these circumstances or events could increase our costs or lower our revenues.

We are dependent on the use or availability of third-party assets for certain of our operations.

Certain of our business activities require the use or availability of third-party assets over which we may have little or no control. If at any time the availability of these assets is limited or denied, and if access to alternative assets cannot be arranged, it could have an adverse effect on our business, results of operations and cash flow.

Non-utilization of certain assets could significantly reduce our profitability due to fixed costs incurred to obtain the right to use such assets.

From time to time in connection with our business, we may lease or otherwise secure the right to use certain assets (such as railcars, trucks, barges, ships, pipeline capacity, storage capacity and other similar assets) with the expectation that the revenues we generate through the use of such assets will be greater than the fixed costs we incur pursuant to the applicable leases or other arrangements. However, when such assets are not utilized or are under-utilized, our profitability could be negatively impacted because the revenues we earn are either non-existent or reduced, but we remain obligated to continue paying any applicable fixed charges, in addition to the potential of incurring other costs attributable to the non-utilization of such assets. Non-utilization of assets we lease or otherwise secure the right to use in connection with our business could have a significant negative impact on our profitability and cash flows.

Many of our assets have been in service for many years and require significant expenditures to maintain them. As a result, our maintenance or repair costs may increase in the future.

Our pipelines, terminals, storage and processing and fractionation assets are generally long-lived assets, and many of them have been in service for many years. The age and condition of our assets could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make cash distributions to our unitholders.

Table of Contents

We do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and therefore are potentially subject to more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. In some instances, we obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Following a decision issued in May 2017 by the Tenth Circuit Court of Appeals, tribal ownership of even a very small fractional interest in tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where existing pipeline rights-of-way may soon lapse or terminate serves as an additional potential impediment for pipeline operations. In September 2018, the Fourth Circuit Court of Appeals reversed a decision of the United States Forest Service ("USFS") issuing a permit for the construction of a pipeline and granting a right of way across the Appalachian Trail, ruling that the USFS lacked statutory authority. This decision may make it more difficult to obtain permits and rights of way on certain federal lands and may be used as precedent to challenge existing and future permits and rights of way. We cannot guarantee that we will always be able to renew existing rights-of-way or obtain new rights-of-way on favorable terms or without experiencing significant delays and costs. Any loss of rights with respect to real property, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, and financial position.

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

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

- a failure on the part of our storage facilities to perform as we expect them to, whether due to malfunction of equipment or facilities or realization of other operational risks;
- the operating pressure of our storage facilities (affected in varying degree, depending on the type of storage cavern, by total volume of working and base gas, and temperature);
- a variety of commercial decisions we make from time to time in connection with the management and operation of our storage facilities. Examples include, without limitation, decisions with respect to matters such as (i) the aggregate amount of commitments we are willing to make with respect to wheeling, injection, and withdrawal services, which could exceed our capabilities at any given time for various reasons, (ii) the timing of scheduled and unplanned maintenance or repairs, which can impact equipment availability and capacity, (iii) the schedule for and rate at which we conduct opportunistic leaching activities at our facilities in connection with the expansion of existing salt caverns, which can impact the amount of storage capacity we have available to satisfy our customers' requests, (iv) the timing and aggregate volume of any base gas park and/or loan transactions we consummate, which can directly affect the operating pressure of our storage facilities and (v) the amount of compression capacity and other gas handling equipment that we install at our facilities to support gas wheeling, injection and withdrawal activities; and
- adverse operating conditions due to hurricanes, extreme weather events or conditions, and operational problems or issues with third-party pipelines, storage or production facilities.

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

If we fail to obtain materials in the quantity and the quality we need, and at commercially acceptable prices, whether due to tariffs, quotas or other factors, our results of operations, financial condition and cash flows could be materially and adversely affected.

Our business requires access to steel and other materials to construct and maintain new and existing pipelines and facilities. If we experience a shortage in the supply of these materials or are unable to source sufficient quantities of high quality materials at acceptable prices and in a timely manner, it could materially and adversely affect our ability to construct new infrastructure and maintain our existing assets.

In addition, some of the materials used in our business are imported. Existing and future import duties and quotas could materially increase our costs of procuring imported or domestic steel and/or create shortages or difficulties in procuring sufficient quantities of steel meeting our required technical specifications. A material increase in our costs of construction and maintenance or any significant delays in our ability to complete our infrastructure projects could have a material adverse effect on our financial position, results of operations and cash flows.

Risks Inherent in an Investment in Us

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf. In addition, we are required to pay all direct and indirect expenses of the Plains Entities, other than income taxes of any of the PAGP Entities. The reimbursement of expenses and the payment of fees and expenses could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by the general partner.

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

Because distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, levels of financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Our levels of financial reserves are established by our general partner and include reserves for the proper conduct of our business (including future capital expenditures and anticipated credit needs), compliance with law or contractual obligations and funding of future distributions to our Series A and Series B preferred unitholders. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

Our preferred units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

Our Series A preferred units and Series B preferred units (together our “preferred units”) rank senior to all of our other classes or series of equity securities with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for our common units, or could make it more difficult for us to sell our common units in the future.

In addition, distributions on the preferred units accrue and are cumulative, at the rate of 8% per annum with respect to our Series A preferred units and 6.125% with respect to our Series B preferred units on the original issue price. Our Series A preferred units are convertible into common units by the holders of such units or by us in certain circumstances. Our Series B preferred units are not convertible into common units, but are redeemable by us in certain circumstances. Our obligation to pay distributions on our preferred units, or on the common units issued following the conversion of our Series A preferred units, could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Our obligations to the holders of preferred units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

Table of Contents

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

Our general partner manages and operates the Partnership. If unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner. Our general partner may not be removed except upon the vote of the holders of at least $66^2/_3$% of our outstanding units (including units held by our general partner or its affiliates). Because AAP owns approximately 39% of our outstanding common units and the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

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

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter, except that such shares constituting up to 19.9% of the total shares outstanding may be voted in the election of PAGP GP directors; and
- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders' ability to influence the manner or direction of management.

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

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

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

- an existing unitholder's proportionate ownership interest in the Partnership will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

In addition, our Series A preferred units are convertible into common units at any time after January 28, 2018 by the holders of such units, or under certain circumstances, at our option. If a substantial portion of the Series A preferred units were converted into common units, common unitholders could experience significant dilution. In addition, if holders of such converted Series A preferred units were to dispose of a substantial portion of these common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for our common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them and/or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units.

Table of Contents

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business and unitholders may have liability to repay distributions under certain circumstances.

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

Furthermore, under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount.

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;
- the amount of cash expenditures, borrowings and reserves in any quarter may affect available cash to pay quarterly distributions to unitholders;
- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner's liability; under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arms length negotiations; and
- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

The control of our general partner may be transferred to a third party without unitholder consent. A change of control may result in defaults under certain of our debt instruments and the triggering of payment obligations under compensation arrangements.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the ultimate owners of our general partner to directly or indirectly transfer their ownership interest in our general partner to a third party. Any new owner of our general partner would, subject to obtaining any approvals or consents required under the applicable governing documents for the PAGP entities, be able to replace the board of directors and officers with its own choices and to control their decisions and actions.

In addition, a change of control would constitute an event of default under our revolving credit agreements. During the continuance of an event of default under our revolving credit agreements, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us under our revolving credit facility and/or declare all amounts payable by us under our revolving credit facility immediately due and payable. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

Table of Contents

Risks Related to an Investment in Our Debt Securities

The right to receive payments on our outstanding debt securities is unsecured and will be effectively subordinated to our existing and future secured indebtedness and will be structurally subordinated as to any existing and future indebtedness and other obligations of our subsidiaries, other than subsidiaries that may guarantee our debt securities in the future.

Our debt securities are effectively subordinated to claims of our secured creditors and to any existing and future indebtedness and other obligations of our subsidiaries, including trade payables, other than subsidiaries that may guarantee our debt securities in the future. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary, other than a subsidiary that may guarantee our debt securities in the future, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of our debt securities.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

Our leverage is significant in relation to our partners' capital. At December 31, 2018, the face value of our total outstanding long-term debt was approximately $9.2 billion, and the face value of our total outstanding short-term debt was approximately $0.1 billion. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facilities and other debt instruments may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Our leverage could have important consequences to investors in our debt securities. We will require substantial cash flow to meet our principal and interest obligations with respect to our debt securities and our other consolidated indebtedness. Our ability to make scheduled payments, to refinance our obligations with respect to our indebtedness or our ability to obtain additional financing in the future will depend on our financial and operating performance, which, in turn, is subject to prevailing economic conditions and to financial, business and other factors. We believe that we will have sufficient cash flow from operations and available borrowings under our bank credit facilities to service our indebtedness, although the principal amount of our debt securities will likely need to be refinanced at maturity in whole or in part. A significant downturn in the hydrocarbon industry or other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or a portion of our debt or sell assets. We can give no assurance that we would be able to refinance our existing indebtedness or sell assets on terms that are commercially reasonable.

Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

The ability to transfer our debt securities may be limited by the absence of an organized trading market.

We do not currently intend to apply for listing of our debt securities on any securities exchange or stock market. The liquidity of any market for our debt securities will depend on the number of holders of those debt securities, the interest of securities dealers in making a market in those debt securities and other factors. Accordingly, we can give no assurance as to the development, continuation or liquidity of any market for the debt securities.

Table of Contents

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may restrict our ability to receive funds from such subsidiaries and make payments on our debt securities.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make required payments on our debt securities depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. Pursuant to our credit facilities, we may be required to establish cash reserves for the future payment of principal and interest on the amounts outstanding under our credit facilities. If we are unable to obtain the funds necessary to pay the principal amount at maturity of our debt securities, or to repurchase our debt securities upon the occurrence of a change of control, we may be required to adopt one or more alternatives, such as a refinancing of our debt securities. We can give no assurance that we would be able to refinance our debt securities.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service our debt securities or to repay them at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our available cash to our unitholders of record. Available cash is generally all of our cash receipts adjusted for cash distributions and net changes to reserves. Our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating partnerships in amounts the general partner determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);
- to comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation;
- to provide funds to make payments on the preferred units; or
- to provide funds for distributions to our common unitholders for any one or more of the next four calendar quarters.

Although our payment obligations to our unitholders are subordinate to our payment obligations to debtholders, the value of our units will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue equity to recapitalize.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes and not being subject to a material amount of entity-level taxation. If the Internal Revenue Service (“IRS”) were to treat us as a corporation for federal income tax purposes, or we become subject to entity-level taxation for state or foreign tax purposes, our cash available for distributions to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a “qualifying income” requirement, as defined in Section 7704 of the Internal Revenue Code of 1986, as amended. Based upon our current operations and current Treasury Regulations, we believe we satisfy the qualifying income requirement. However, no ruling has been or will be requested regarding our treatment as a partnership for U.S. federal income tax purposes. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, and would likely pay state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Table of Contents

In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are subject to entity-level tax on the portion of our income apportioned to Texas. Imposition of any similar taxes or additional federal or foreign taxes on us will reduce the cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress have proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including a prior legislative proposal that would have eliminated the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no current legislative or administrative proposals, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a publicly traded partnership in the future.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

If the IRS or Canada Revenue Agency ("CRA") contests the federal income tax positions or inter-country allocations we take, the market for our common units may be adversely impacted and the cost of any IRS or CRA contest or incremental taxes paid will reduce our cash available for distribution or debt service.

The IRS has made no determination as to our status as a partnership for federal income tax purposes or as to any other matter affecting us. The IRS or CRA may adopt positions that differ from the positions we take or challenge the inter-country allocations we make. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS or CRA may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS or CRA and any incremental taxes required to be paid will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution or debt service. See Note 14 for additional information regarding CRA challenge of intercompany transactions.

Table of Contents

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Taxable gain or loss on the disposition of our common units could be more or less than expected.

If a unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and that unitholder's tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease such unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units a unitholder sells will, in effect, become taxable income to a unitholder if it sells such units at a price greater than its tax basis in those units, even if the price such unitholder receives is less than its original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells its units, a unitholder may incur a tax liability in excess of the amount of cash received from the sale.

A substantial portion of the amount realized from a unitholder's sale of our units, whether or not representing a gain, may be taxed as ordinary income to such unitholder due to potential recapture items, including depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. If our "business interest" is subject to limitation under these rules, our unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. With respect to taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Table of Contents

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the Non-U.S. unitholder.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

Our unitholders will likely be subject to state, local and non-U.S. taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our units.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in multiple states that currently impose a personal income tax on individuals and an income tax on corporations and other entities. It is our unitholders' responsibility to file all U.S. federal, state, local and non-U.S. tax returns, as applicable. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, which could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Table of Contents

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered to have disposed of those common units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units may be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month (the "Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for (i) depreciation and amortization of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets, and (iii) in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

Taxable income from our non-U.S. businesses is not eligible for the 20% deduction for qualified publicly traded partnership income.

Pursuant to the Tax Cuts and Jobs Acts, a unitholder is generally allowed to a deduction equal to 20% of our "qualified publicly traded partnership income" that is allocated to such unitholder. For purposes of the deduction, the term qualified publicly traded partnership income includes the net amount of such unitholder's allocable share of our income that is effectively connected to our U.S. trade or business activities. Because our non-U.S. business operations earn income that is not effectively connected with a U.S. trade or business, unitholders may not apply the 20% deduction for qualified publicly traded partnership income to that portion of our income.

Tax Risks to Series B Preferred Unitholders

Treatment of distributions on our Series B Preferred Units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our Series B Preferred Units than the holders of our common units and, under recently issued U.S. Treasury Regulations, such distributions are not eligible for the 20% deduction for qualified publicly traded partnership income in our taxable years beginning on or after January 1, 2020.

The tax treatment of distributions on our Series B Preferred Units is uncertain. We will treat the holders of Series B Preferred Units as partners for tax purposes and will treat distributions on the Series B Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Series B Preferred Units as ordinary income. Although a holder of Series B Preferred Units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous cash distribution. We anticipate accruing and making the guaranteed payment distributions semi-annually on May 15th and November 15th through November 15th, 2022 commencing November 15, 2017, and after November 15, 2022 quarterly on February 15th, May 15th, August 15th and November 15th. Because the guaranteed payment for each unit must accrue as income to a holder during the taxable year of the accrual, the guaranteed payment attributable to the period beginning November 15th and ending December 31st will accrue to the holder of record of a Series B Preferred Unit on December 31st for such period. If you are a taxpayer reporting your income using the accrual method, or using a taxable year other than the calendar year, you should consult your tax advisor with respect to the consequences of our guaranteed payment distribution accrual and reporting convention. Otherwise, the holders of Series B Preferred Units are generally not

Table of Contents

anticipated to share in the partnership's items of income, gain, loss or deduction, except to the extent necessary to (i) achieve parity with the Series A Preferred Units or (ii) provide, to the extent possible, the Series B Preferred Units with the benefit of the liquidation preference. The Partnership will not allocate any share of our nonrecourse liabilities to the holders of Series B Preferred Units. If the Series B Preferred Units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of Series B Preferred Units.

Although we expect that a substantial portion of the income we earn is generally eligible for the 20% deduction for qualified publicly traded partnership income, recently issued U.S. Treasury Regulations, which are effective for our taxable years beginning on or after January 1, 2020, provide that a guaranteed payment for the use of capital is not eligible for the 20% deduction for qualified publicly traded partnership income. As a result, it is unclear whether a guaranteed payment for use of capital received by our Series B Preferred Units in our 2018 or 2019 taxable years may be eligible for the 20% deduction for qualified publicly traded partnership income. All holders of our Series B Preferred Units are urged to consult a tax advisor to determine whether they are eligible to receive the 20% deduction for qualified publicly traded partnership income with respect to their Series B Preferred Units.

A holder of Series B Preferred Units will be required to recognize gain or loss on a sale of Series B Units equal to the difference between the amount realized by such holder and such holder's tax basis in the Series B Preferred Units. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such Series B Preferred Units. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of a Series B Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the holder to acquire such Series B Preferred Unit. Gain or loss recognized by a holder on the sale or exchange of a Series B Preferred Unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of Series B Preferred Units will generally not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in the Series B Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts, and non-U.S. persons raises issues unique to them. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income for U.S. federal income tax purposes. Although the issue is not free from doubt, we will treat a substantial portion of our distributions to non-U.S. holders of the Series B Preferred Units as "effectively connected income" (which will subject holders to U.S. net income taxation and possibly the branch profits tax) that is subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders may be required to file U.S. federal income tax returns in order to seek a refund of such excess.

All holders of our Series B Preferred Units are urged to consult a tax advisor with respect to the consequences of owning our Series B Preferred Units.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

The information required by this item is included in Note 18 to our Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 4. Mine Safety Disclosures

Not applicable.

Table of Contents

PART II

Item 5. Market for Registrant’s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities

Market Information, Holders and Distributions

Our common units are listed and traded on the New York Stock Exchange under the symbol “PAA.” As of February 12, 2019, there were 726,579,550 common units outstanding and approximately 109,500 record holders and beneficial owners (held in street name).

The following table presents cash distributions per common unit pertaining to the quarter presented, which were declared and paid in the following calendar quarter (see the “Cash Distribution Policy” section below for a discussion of our policy regarding distribution payments):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2018	$ 0.30	$ 0.30	$ 0.30	$ 0.30
2017	$ 0.55	$ 0.55	$ 0.30	$ 0.30

Our common units are also used as a form of compensation to our employees and PAGP GP directors. See Note 17 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Performance Graph

The following graph compares the total unitholder return performance of our common units with the performance of: (i) the Standard & Poor’s 500 Stock Index (“S&P 500”) and (ii) the Alerian MLP Index. The Alerian MLP Index is a composite of the most prominent energy master limited partnerships that provides investors with a comprehensive benchmark for this asset class. The graph assumes that $100 was invested in our common units and each comparison index beginning on December 31, 2013 and that all distributions were reinvested on a quarterly basis.

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018
PAA	$ 100.00	$ 103.83	$ 49.92	$ 77.79	$ 53.41	$ 54.66
S&P 500	$ 100.00	$ 113.69	$ 115.26	$ 129.05	$ 157.22	$ 150.33
Alerian MLP Index	$ 100.00	$ 104.80	$ 70.65	$ 83.58	$ 78.13	$ 68.43

Table of Contents

This information shall not be deemed to be “soliciting material” or to be “filed” with the Commission or subject to Regulation 14A or 14C under the Exchange Act, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act, and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent that we specifically request that such information be treated as soliciting material or specifically incorporate it by reference into a filing under the Securities Act or the Exchange Act.

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

Recent Sales of Unregistered Securities

Pursuant to the Omnibus Agreement entered into in November 2016 as part of the Simplification Transactions, we agreed to issue common units to AAP upon any AAP Management Units becoming earned that were not earned as of the date of the closing of the Simplification Transactions. See Note 1 to our Consolidated Financial Statements for further discussion of the Simplification Transactions. During the three months ended December 31, 2018, we issued 183,814 common units to AAP associated with AAP Management Units that became earned as of October 31, 2018. This issuance was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Issuer Purchases of Equity Securities

None.

Cash Distribution Policy

In accordance with our partnership agreement, after making distributions to holders of our outstanding preferred units, we distribute the remainder of our available cash to our common unitholders of record within 45 days following the end of each quarter. Available cash is generally defined as, for any quarter ending prior to liquidation, all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the reasonable discretion of our general partner for future requirements to:

- provide for the proper conduct of our business and the business of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);
- comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation; or
- provide funds for distributions to our Series A and Series B preferred unitholders or distributions to our common unitholders for any one or more of the next four calendar quarters.

Our available cash also includes cash on hand resulting from borrowings made after the end of the quarter.

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. No such default has occurred. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreements, Commercial Paper Program and Indentures.”

Under the terms of our partnership agreement, our Series A preferred units and our Series B preferred units rank senior to all classes or series of equity securities in us with respect to distribution rights.

Table of Contents

Item 6. Selected Financial Data

The historical financial information below was derived from our audited Consolidated Financial Statements as of December 31, 2018, 2017, 2016, 2015 and 2014 and for the years then ended. The selected financial data should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," and the Consolidated Financial Statements, including the notes thereto, in Item 8. "Financial Statements and Supplementary Data."

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in millions, except per unit data and volumes)				
Statement of operations data:					
Total revenues	$34,055	$26,223	$20,182	$23,152	$43,464
Operating income	$2,277	$1,153	$994	$1,262	$1,799
Net income	$2,216	$858	$730	$906	$1,386
Net income attributable to PAA	$2,216	$856	$726	$903	$1,384
Per unit data:					
Basic net income per common unit	$2.77	$0.96	$0.43	$0.78	$2.39
Diluted net income per common unit	$2.71	$0.95	$0.43	$0.77	$2.38
Declared distributions per common unit [1]	$1.20	$1.95	$2.65	$2.76	$2.55
Balance sheet data (at end of period):					
Property and equipment, net	$14,787	$14,089	$13,872	$13,474	$12,272
Total assets	$25,511	$25,351	$24,210	$22,288	$22,198
Long-term debt	$9,143	$9,183	$10,124	$10,375	$8,704
Total debt	$9,209	$9,920	$11,839	$11,374	$9,991
Partners' capital	$12,002	$10,958	$8,816	$7,939	$8,191
Other data:					
Net cash provided by operating activities	$2,608	$2,499	$733	$1,358	$2,023
Net cash used in investing activities	$(813)	$(1,570)	$(1,273)	$(2,530)	$(3,296)
Net cash provided by/(used in) financing activities	$(1,757)	$(943)	$556	$800	$1,638
Capital expenditures:					
Acquisition capital	$—	$1,323	$289	$105	$1,099
Expansion capital	$1,888	$1,135	$1,405	$2,170	$2,026
Maintenance capital	$252	$247	$186	$220	$224

Table of Contents

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Volumes [(2)] [(3)]					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	5,791	5,083	4,523	4,340	3,952
Trucking	98	103	114	113	127
Transportation segment total volumes	5,889	5,186	4,637	4,453	4,079
Facilities segment:					
Liquids storage (average monthly capacity in millions of barrels)	109	112	107	100	95
Natural gas storage (average monthly working capacity in billions of cubic feet)	66	82	97	97	97
NGL fractionation (average volumes in thousands of barrels per day)	131	126	115	103	96
Facilities segment total volumes (average monthly volumes in millions of barrels)	124	130	127	120	114
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	1,054	945	894	943	949
NGL sales	255	274	259	223	208
Supply and Logistics segment total volumes	1,309	1,219	1,153	1,166	1,157

(1) Represents cash distributions declared and paid per unit during the year presented. See Note 12 to our Consolidated Financial Statements for further discussion regarding our distributions.

(2) Average volumes are calculated as the total volumes (attributable to our interest) for the year divided by the number of days or months in the year.

(3) Facilities segment total is calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 thousand cubic feet ("mcf") of natural gas to crude British thermal unit ("Btu") equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the year and divided by the number of months in the year.

Table of Contents

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

Introduction

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

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions and Capital Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services primarily for crude oil, NGL and natural gas. 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. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: Transportation, Facilities and Supply and Logistics. See "—Results of Operations—Analysis of Operating Segments" for further discussion.

Overview of Operating Results, Capital Investments and Other Significant Activities

We recognized net income of $2.2 billion in 2018 compared to net income of $858 million recognized in 2017. This year-over-year increase reflects:

- Favorable regional crude oil differentials and higher lease gathering and NGL margins in our Supply and Logistics segment, as well as more favorable impacts in the 2018 period from the mark-to-market of certain derivative instruments;

- Favorable results from our Transportation segment, primarily from our pipelines in the Permian Basin region, driven by higher volumes from increased production and our recently completed capital expansion projects, which more than offset the impact of asset sales;

- Net gains recognized during the 2018 period associated with asset sales (including a gain on the sale of a portion of our interest in BridgeTex), as compared to net losses recognized during the 2017 period associated with asset sales, impairments and accelerated depreciation; and

- Lower interest expense primarily driven by a lower weighted average debt balance in the 2018 period as a result of our efforts to implement our Leverage Reduction Plan announced in August 2017 (discussed further below); partially offset by

- Higher income tax expense due to higher year-over-year income as impacted by fluctuations in derivative mark-to-market valuations in our Canadian operations.

See further discussion of our segment operating results in the "—Results of Operations—Analysis of Operating Segments" and "—Other Income and Expenses" sections below. See the "Outlook—Market Overview and Outlook" section below for a discussion of the market and our current outlook.

Table of Contents

We invested approximately $1.9 billion in midstream infrastructure projects during 2018, which primarily included takeaway pipelines in the Permian Basin and other complementary Permian Basin projects. See the "—Acquisitions, Capital Projects and Divestitures" section below for additional information.

We funded such capital activities primarily from proceeds received from asset sales as part of our divestiture program, which totaled approximately $1.3 billion for 2018. In addition, we progressed our Leverage Reduction Plan, as discussed further below. We also paid approximately $1.0 billion of cash distributions to our common unitholders and our Series A and B preferred unitholders during 2018.

Leverage Reduction Plan

On August 25, 2017, we announced that we were implementing an action plan to strengthen our balance sheet, reduce leverage, enhance our distribution coverage, minimize new issuances of common equity and position the Partnership for future distribution growth. The action plan ("Leverage Reduction Plan"), which was endorsed by the PAGP GP Board, included our intent to achieve certain objectives. During 2017 and 2018, we made meaningful progress in executing our Leverage Reduction Plan and remain on track to achieve our objectives in the first half of 2019. However, there can be no assurance that the objectives of our Leverage Reduction Plan remaining to be achieved will be achieved, or that they will be achieved within our desired time frame or in the desired amounts. Achievement of such objectives is subject to risks and uncertainties, many of which are outside of our control. Please see "Risk Factors—Risks Related to Our Business."

Acquisitions, Capital Projects and Divestitures

Acquisitions and Capital Projects

We completed a number of acquisitions and capital projects in 2018, 2017 and 2016 that have impacted our results of operations. The following table summarizes our expenditures for acquisition capital, expansion capital and maintenance capital for such periods (in millions):

	Year Ended December 31,		
	2018	2017	2016
Acquisition capital (1)	$ —	$ 1,323	$ 289
Expansion capital (1) (2)	1,888	1,135	1,405
Maintenance capital (2)	252	247	186
	$ 2,140	$ 2,705	$ 1,880

(1) Acquisitions of initial investments or additional interests in unconsolidated entities are included in "Acquisition capital." Subsequent contributions to unconsolidated entities related to expansion projects of such entities are recognized in "Expansion capital." We account for our investments in such entities under the equity method of accounting.

(2) Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as "Expansion capital." Capital expenditures for the replacement and/or refurbishment of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets are classified as "Maintenance capital."

Table of Contents

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our commercial paper program or credit facilities and the issuance of senior notes. In addition, we may also use excess cash flow from operations and proceeds from sales of assets for funding. Businesses acquired impact our results of operations commencing on the closing date of each acquisition. Our acquisition activities are discussed further in "—Liquidity and Capital Resources." We did not complete any acquisitions during 2018. Information regarding acquisitions completed in 2017 and 2016 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Alpha Crude Connector Gathering System	February 2017	$ 1,215	Transportation
Other	Various	108	Transportation and Facilities
2017 Total		$ 1,323	
Western Canada NGL Assets	August 2016	$ 204	Transportation and Facilities
Other	Various	85	Transportation
2016 Total		$ 289	

Expansion Capital Projects

Our 2018 projects primarily included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2018, 2017 and 2016 projects (in millions):

Projects	2018	2017	2016
Permian Basin Takeaway Pipeline Projects (1) (2)	$880	$59	$26
Complementary Permian Basin Projects (2)	671	217	224
Selected Facilities Projects (3)	62	134	313
Red River Pipeline	1	10	306
Diamond Pipeline (4)	17	318	104
Other Projects	257	397	432
Total	$1,888	$1,135	$1,405

(1) Represents pipeline projects with takeaway capacity out of the Permian Basin, including our Sunrise expansion and our 65% interest in the Cactus II Pipeline.
(2) These projects will continue into 2019. See "—Liquidity and Capital Resources—Acquisitions, Investments, Expansion Capital Expenditures and Divestitures —2019 Capital Projects."
(3) Includes projects at our St. James, Fort Saskatchewan and Cushing terminals.
(4) Represents contributions related to our 50% interest in Diamond Pipeline LLC.

Our recent expansion capital programs were primarily driven by investment in midstream infrastructure projects to address the need for additional takeaway capacity in regions impacted by the increase in crude oil and liquids-rich gas production growth in North America, as well as the long-term needs of both the upstream and downstream sectors of the crude oil space. Substantially all of the expansion capital spent in the years presented was invested in our fee-based Transportation and Facilities segments.

We currently expect to spend approximately $1.1 billion for expansion capital in 2019. See "—Liquidity and Capital Resources—Acquisitions, Investments, Expansion Capital Expenditures and Divestitures —2019 Capital Projects" and "Outlook—Market Overview and Outlook" for additional information.

78

Table of Contents

Divestitures

In 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. As of December 31, 2018, we had completed asset sales totaling approximately $3.0 billion. The following table summarizes the proceeds received for sales of assets, which were previously reported in our Transportation and Facilities segments, during the years ended December 31, 2018, 2017 and 2016 (in millions):

	Year Ended December 31,		
	2018	2017	2016
Proceeds from sales of assets	$1,334	$1,083	$569 (1)

(1) Net of amounts paid for the remaining interest in a non-core pipeline that was subsequently sold.

Proceeds from asset sales were used to fund our expansion capital program and reduce debt levels. See "—Liquidity and Capital Resources" for additional discussion of our divestiture activities.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP and rules and regulations of the SEC requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. On a regular basis, we evaluate our assumptions, judgments and estimates. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

We believe that the assumptions, judgments and estimates involved in the accounting for our (i) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (ii) impairment assessments of goodwill and intangible assets, (iii) fair value of derivatives, (iv) accruals and contingent liabilities, (v) equity-indexed compensation plan accruals, (vi) property and equipment, depreciation and amortization expense, asset retirement obligations and impairments, (vii) allowance for doubtful accounts and (viii) inventory valuations have the greatest potential impact on our Consolidated Financial Statements. These areas are key components of our results of operations and are based on complex rules which require us to make judgments and estimates. Therefore, we consider these to be our critical accounting policies and estimates, which are discussed further as follows. For further information on all of our significant accounting policies, see Note 2 to our Consolidated Financial Statements.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with FASB guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recorded. We also expense the transaction costs as incurred in connection with each acquisition, except for acquisitions of equity method investments. In addition, we are required to recognize intangible assets separately from goodwill.

Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, acreage dedications and other contracts, involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired and, to the extent available, third party assessments.

Impairment Assessments of Goodwill and Intangible Assets. Goodwill and intangible assets with indefinite lives are not amortized but are instead periodically assessed for impairment. See Note 8 to our Consolidated Financial Statements for further discussion of goodwill. Intangible assets with finite lives are amortized over their estimated useful life as determined by management.

Impairment testing entails estimating future net cash flows relating to the business, based on management's estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors, such as weighted average cost of capital. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Resolutions of these uncertainties have resulted, and in the future may result, in impairments that impact our results of operations and financial condition.

Fair Value of Derivatives. The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. We have commodity derivatives, interest rate derivatives and foreign currency derivatives that are accounted for as assets and liabilities at fair value in our Consolidated Balance Sheets. The valuations of our derivatives that are exchange traded are based on market prices on the applicable exchange on the last day of the period. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total annual revenues are based on estimates derived from internal valuation models.

We also have embedded derivatives in our Series A preferred units that are recorded at fair value on our Consolidated Balance Sheets. These embedded derivatives are valued using a model that contains inputs, including our common unit price, ten-year U.S. Treasury rates, default probabilities and timing estimates, some of which involve management judgment.

Although the resolution of the uncertainties involved in these estimates has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 13 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Accruals and Contingent Liabilities. We record accruals or liabilities for, among other things, environmental remediation, natural resource damage assessments, governmental fines and penalties, potential legal claims and fees for legal services associated with loss contingencies, and bonuses. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, the duration of the natural resource damage assessment and the ultimate amount of damages determined, the determination and calculation of fines and penalties, the possibility of existing legal claims giving rise to additional claims and the nature, extent and cost of legal services that will be required in connection with lawsuits, claims and other matters. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A hypothetical variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $19 million. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Equity-Indexed Compensation Plan Accruals. We accrue compensation expense (referred to herein as equity-indexed compensation expense) for outstanding equity-indexed compensation awards. Under GAAP, we are required to estimate the fair value of our outstanding equity-indexed compensation awards and recognize that fair value as compensation expense over the service period. For equity-indexed compensation awards that contain a performance condition, the fair value of the award is recognized as equity-indexed compensation expense only if the attainment of the performance condition is considered probable. Uncertainties involved in this estimate include future levels of four quarter trailing distributable cash flow (“DCF”) per common unit and whether or not a performance condition will be attained. In addition, the common unit price at the end of each period (and at the time of vesting) will impact the amount of compensation expense recorded in each period for certain awards. We cannot provide assurance that the actual fair value of our equity-indexed compensation awards will not vary significantly from estimated amounts.

We recognized equity-indexed compensation expense of $79 million, $41 million and $60 million in 2018, 2017 and 2016, respectively, related to awards granted under our various equity-indexed compensation plans. A hypothetical variance of 5% in our aggregate estimate for the equity-indexed compensation expense would have an impact on our total costs and expenses of less than 1%. See Note 17 to our Consolidated Financial Statements for a discussion regarding our equity-indexed compensation plans.

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

We record retirement obligations associated with tangible long-lived assets based on estimates related to the costs associated with cleaning, purging and, in some cases, completely removing the assets and returning the land to its original state. In addition, our estimates include a determination of the settlement date or dates for the potential obligation, which may or may not be determinable. Uncertainties that impact these estimates include the costs associated with these activities and the timing of incurring such costs.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. Any evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property and equipment a critical accounting estimate. In determining the existence of an impairment of carrying value, we make a number of subjective assumptions as to:

- whether there is an event or circumstance that may be indicative of an impairment;
- the grouping of assets;
- the intention of “holding”, “abandoning” or “selling” an asset;
- the forecast of undiscounted expected future cash flow over the asset’s estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

In addition, when we evaluate property and equipment and other long-lived assets for recoverability, it may also be necessary to review related depreciation estimates and methods.

A change in our outlook or use could result in impairments that may be material to our results of operations or financial condition. See the “—Outlook— Market Overview and Outlook” section below and Note 6 to our Consolidated Financial Statements for additional information.

Allowance for Doubtful Accounts. We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal (less than $2 million in the aggregate over the years ended December 31, 2018, 2017 and 2016) and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for additional discussion.

Inventory Valuations. Inventory, including long-term inventory, primarily consists of crude oil, NGL and natural gas and is valued at the lower of cost or net realizable value, with cost determined using an average cost method within specific inventory pools. At the end of each reporting period, we assess the carrying value of our inventory and use estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact our estimates are the applicable quality and location differentials to include in our net realizable value analysis. Additionally, we estimate the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value. During the years ended

December 31, 2018, 2017 and 2016, we recorded charges of $8 million, $35 million and $3 million, respectively, related to the valuation adjustment of our crude oil, NGL and natural gas inventory due to declines in prices. See Note 5 to our Consolidated Financial Statements for further discussion regarding inventory.

Table of Contents

Recent Accounting Pronouncements

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

Results of Operations

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

	Year Ended December 31,			Variance 2018-2017		2017-2016	
	2018	2017	2016	$	%	$	%
Transportation Segment Adjusted EBITDA [1]	$1,508	$1,287	$1,141	$221	17 %	$146	13 %
Facilities Segment Adjusted EBITDA [1]	711	734	667	(23)	(3)%	67	10 %
Supply and Logistics Segment Adjusted EBITDA [1]	462	60	359	402	**	(299)	(83)%
Adjustments:							
Depreciation and amortization of unconsolidated entities	(56)	(45)	(50)	(11)	(24)%	5	10 %
Selected items impacting comparability - Segment Adjusted EBITDA	433	33	(434)	400	**	467	**
Depreciation and amortization	(520)	(517)	(514)	(3)	(1)%	(3)	(1)%
Gains/(losses) on asset sales and asset impairments, net [2]	114	(109)	20	223	205 %	(129)	**
Gain on sale of investment in unconsolidated entities	200	—	—	200	N/A	—	N/A
Interest expense, net	(431)	(510)	(467)	79	15 %	(43)	(9)%
Other income/(expense), net	(7)	(31)	33	24	77 %	(64)	(194)%
Income tax expense	(198)	(44)	(25)	(154)	(350)%	(19)	(76)%
Net income	2,216	858	730	1,358	158 %	128	18 %
Net income attributable to noncontrolling interests	—	(2)	(4)	2	100 %	2	50 %
Net income attributable to PAA	$2,216	$856	$726	$1,360	159 %	$130	18 %
Basic net income per common unit	$2.77	$0.96	$0.43	$1.81	**	$0.53	**
Diluted net income per common unit	$2.71	$0.95	$0.43	$1.76	**	$0.52	**
Basic weighted average common units outstanding	726	717	464	9	**	253	**
Diluted weighted average common units outstanding	799	718	466	81	**	252	**

** Indicates that variance as a percentage is not meaningful.

(1) Segment Adjusted EBITDA is the measure of segment performance that is utilized by our Chief Operating Decision Maker (“CODM”) to assess performance and allocate resources among our operating segments. This measure is adjusted for certain items, including those that our CODM believes impact comparability of results across periods. See Note 20 to our Consolidated Financial Statements for additional discussion of such adjustments.

(2) Effective for the fourth quarter of 2018, we reclassified amounts related to gains and losses on asset sales and asset impairments from “Depreciation and amortization” to “(Gains)/losses on asset sales and asset impairments, net” on our Consolidated Statements of Operations. This change was applied retrospectively. See Note 1 to our Consolidated Financial Statements for additional discussion.

Table of Contents

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future. The primary additional measures used by management are earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization and gains and losses on significant asset sales of unconsolidated entities), gains and losses on asset sales and asset impairments, and gains on sales of investments in unconsolidated entities, adjusted for certain selected items impacting comparability (“Adjusted EBITDA”) and implied DCF.

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations, (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions and (iii) present measures that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These non-GAAP measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) gains or losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), the mark-to-market related to our Preferred Distribution Rate Reset Option, gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) other items that we believe should be excluded in understanding our core operating performance. These measures may further be adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in “Other current liabilities” in our Consolidated Financial Statements. Such amounts are presented net of applicable amounts subsequently recognized into revenue. We have defined all such items as “selected items impacting comparability.” We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

Although we present selected items impacting comparability that management considers in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions, expansion projects and numerous other factors as discussed, as applicable, in “Analysis of Operating Segments.”

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA and Implied DCF are reconciled to Net Income, the most directly comparable measure as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Consolidated Financial Statements and footnotes.

Table of Contents

The following table sets forth the reconciliation of these non-GAAP financial performance measures from Net Income (in millions):

	Year Ended December 31,			Variance 2018-2017		2017-2016	
	2018	2017	2016	$	%	$	%
Net income	$2,216	$858	$730	$1,358	158 %	$128	18 %
Add/(Subtract):							
Interest expense, net	431	510	467	(79)	(15)%	43	9 %
Income tax expense	198	44	25	154	350 %	19	76 %
Depreciation and amortization	520	517	514	3	1 %	3	1 %
(Gains)/losses on asset sales and asset impairments, net	(114)	109	(20)	(223)	(205)%	129	**
Depreciation and amortization of unconsolidated entities (1)	56	45	50	11	24 %	(5)	(10)%
Gain on sale of investment in unconsolidated entities	(200)	—	—	(200)	N/A	—	N/A
Selected Items Impacting Comparability:							
(Gains)/losses from derivative activities net of inventory valuation adjustments (2)	(519)	(46)	404	(473)	**	(450)	**
Long-term inventory costing adjustments (3)	21	(24)	(58)	45	**	34	**
Deficiencies under minimum volume commitments, net (4)	7	2	46	5	**	(44)	**
Equity-indexed compensation expense (5)	55	23	33	32	**	(10)	**
Net (gain)/loss on foreign currency revaluation (6)	3	(26)	9	29	**	(35)	**
Line 901 incident (7)	—	32	—	(32)	**	32	**
Significant acquisition-related expenses (8)	—	6	—	(6)	**	6	**
Selected Items Impacting Comparability - Segment Adjusted EBITDA	(433)	(33)	434	(400)	**	(467)	**
(Gains)/losses from derivative activities (2)	14	(13)	(30)	27	**	17	**
Net (gain)/loss on foreign currency revaluation (6)	(4)	5	(1)	(9)	**	6	**
Net loss on early repayment of senior notes (9)	—	40	—	(40)	**	40	**
Selected Items Impacting Comparability - Adjusted EBITDA (10)	(423)	(1)	403	(422)	**	(404)	**
Adjusted EBITDA (10)	$2,684	$2,082	$2,169	$602	29 %	$(87)	(4)%
Interest expense, net (11)	(419)	(483)	(451)	64	13 %	(32)	(7)%
Maintenance capital (12)	(252)	(247)	(186)	(5)	(2)%	(61)	(33)%
Current income tax expense	(66)	(28)	(85)	(38)	(136)%	57	67 %
Adjusted equity earnings in unconsolidated entities, net of distributions (13)	1	(10)	(29)	11	**	19	**
Distributions to noncontrolling interests	—	(2)	(4)	2	100 %	2	50 %
Implied DCF (14)	$1,948	$1,312	$1,414	$636	48 %	$(102)	(7)%
Preferred unit cash distributions (15)	(161)	(5)	—				
General partner cash distributions (16)	—	—	(565)				
Implied DCF Available to Common Unitholders	$1,787	$1,307	$849				
Common unit cash distributions (17)	(871)	(1,386)	(1,062)				
Implied DCF Excess/(Shortage) (18)	$916	$(79)	$(213)				

** Indicates that variance as a percentage is not meaningful.

(1) Over the past several years, we have increased our participation in strategic pipeline joint ventures, which are accounted for under the equity method of accounting. We exclude our proportionate share of the depreciation and amortization expense and gains and losses on significant asset sales by such unconsolidated entities when reviewing Adjusted EBITDA, similar to our consolidated assets.

(2) We use derivative instruments for risk management purposes, and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining Adjusted EBITDA. In addition, we exclude gains and losses on derivatives that are related to investing activities, such as the purchase of linefill. We also exclude the impact of corresponding inventory valuation adjustments, as applicable, as well as the mark-to-market adjustment related to our Preferred Distribution Rate Reset Option. See Note 13 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities and our Preferred Distribution Rate Reset Option.

(3) We carry crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and writedowns of such inventory that result from price declines as a selected item impacting comparability. See Note 5 to our Consolidated Financial Statements for additional inventory disclosures.

(4) We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Substantially all of such agreements were entered into with counterparties to economically support the return on our capital expenditure necessary to construct the related asset. Some of these agreements include make-up rights if the minimum volume is not met. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty's make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty's ability to utilize the make-up right is remote. We include the impact of amounts billed to counterparties for their deficiency obligation, net of applicable amounts subsequently recognized into revenue, as a selected item impacting comparability. We believe the inclusion of the contractually committed revenues associated with that period is meaningful to investors as the related asset has been constructed, is standing ready to provide the committed service and the fixed operating costs are included in the current period results.

(5) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted net income per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted net income per unit calculation, as applicable, and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 17 to our Consolidated Financial Statements for a comprehensive discussion regarding our equity-indexed compensation plans.

(6) During the periods presented, there were fluctuations in the value of the Canadian dollar ("CAD") to the U.S. dollar ("USD"), resulting in gains and losses that were not related to our core operating results for the period and were thus classified as a selected item impacting comparability. See Note 13 to our Consolidated Financial Statements for

discussion regarding our currency exchange rate risk hedging activities.

(7) Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance. See Note 18 to our Consolidated Financial Statements for additional information regarding the Line 901 incident.

(8) Includes acquisition-related expenses associated with the ACC Acquisition in February 2017. See Note 7 to our Consolidated Financial Statements for additional information.

(9) Includes net losses incurred in connection with the early redemption of our (i) $600 million, 6.50% senior notes due May 2018 and (ii) $350 million, 8.75% senior notes due May 2019. See Note 11 to our Consolidated Financial Statements for additional information.

(10) Adjusted EBITDA includes Other income/(expense), net per our Consolidated Statements of Operations, adjusted for selected items impacting comparability ("Adjusted Other income/(expense), net"). Segment Adjusted EBITDA does not include Adjusted Other income/(expense), net.

(11) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

(12) Maintenance capital expenditures are defined as capital expenditures for the replacement and/or refurbishment of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets.

(13) Represents the difference between non-cash equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization and gains and losses on significant asset sales) and cash distributions received from such entities.

(14) Including net costs recognized during the period related to the Line 901 incident that occurred in May 2015, Implied DCF would have been $1,280 million for the year ended December 31, 2017. See Note 18 to our Consolidated Financial Statements for additional information regarding the Line 901 incident.

(15) Cash distributions paid to our preferred unitholders during the period presented. The current $0.5250 quarterly ($2.10 annualized) per unit distribution requirement of our Series A preferred units was paid-in-kind for each quarterly distribution from their issuance through February 2018. Distributions on our Series A preferred units were paid in cash beginning with the May 2018 quarterly distribution. The current $61.25 per unit annual distribution requirement of our Series B preferred units, which were issued in October 2017, is payable semi-annually in arrears on May 15 and November 15. A pro-rated initial distribution on the Series B preferred units was paid on November 15, 2017. See Note 12 to our Consolidated Financial Statements for additional information regarding our preferred units.

(16) The Simplification Transactions, which closed on November 15, 2016, simplified our governance structure and permanently eliminated our IDRs and the economic rights associated with our 2% general partner interest.

(17) Common unit cash distributions paid during the period presented.

(18) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes. DCF shortages may be funded from previously established reserves, cash on hand or from borrowings under our credit facilities or commercial paper program.

Analysis of Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our CODM (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Adjusted EBITDA, segment volumes, Segment Adjusted EBITDA per barrel and maintenance capital investment.

We define Segment Adjusted EBITDA as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses, plus our proportionate share of the depreciation and amortization expense and gains and losses on significant asset sales of unconsolidated entities, and further adjusted for certain selected items including (i) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (ii) long-term inventory costing adjustments, (iii) charges for obligations that are expected to be settled with the issuance of equity instruments, (iv) amounts related to deficiencies associated with minimum volume commitments, net of applicable amounts subsequently recognized into revenue and (v) other items that our CODM believes are integral to understanding our core segment operating performance. See Note 20 to our

Consolidated Financial Statements for a reconciliation of Segment Adjusted EBITDA to net income attributable to PAA.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the Supply and Logistics segment secures transportation and facilities services from our other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market. Facilities segment services are also obtained at rates generally consistent with rates charged to third parties for similar services. Intersegment activities are eliminated in consolidation and we believe that the estimates with

Table of Contents

respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expenses and general and administrative overhead expenses between segments based on management's assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

Revenues and expenses from our Canadian based subsidiaries, which use CAD as their functional currency, are translated at the prevailing average exchange rates for the month.

Transportation Segment

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

The following tables set forth our operating results from our Transportation segment:

				Variance			
Operating Results [1]	Year Ended December 31,			2018-2017		2017-2016	
(in millions, except per barrel data)	2018	2017	2016	$	%	$	%
Revenues	$1,990	$1,718	$1,584	$272	16 %	$134	8 %
Purchases and related costs	(194)	(123)	(94)	(71)	(58)%	(29)	(31)%
Field operating costs	(640)	(593)	(551)	(47)	(8)%	(42)	(8)%
Segment general and administrative expenses [2]	(117)	(101)	(103)	(16)	(16)%	2	2 %
Equity earnings in unconsolidated entities	375	290	195	85	29 %	95	49 %
Adjustments [3]:							
Depreciation and amortization of unconsolidated entities	56	45	50	11	24 %	(5)	(10)%
(Gains)/losses from derivative activities net of inventory valuation adjustments	(1)	—	—	(1)	N/A	—	N/A
Deficiencies under minimum volume commitments, net	9	2	44	7	**	(42)	**
Equity-indexed compensation expense	30	11	16	19	**	(5)	**
Line 901 incident	—	32	—	(32)	**	32	**
Significant acquisition-related expenses	—	6	—	(6)	**	6	**
Segment Adjusted EBITDA	$1,508	$1,287	$1,141	$221	17 %	$146	13 %
Maintenance capital	$139	$120	$121	$19	16 %	$(1)	(1)%
Segment Adjusted EBITDA per barrel	$0.70	$0.68	$0.67	$0.02	3 %	$0.01	1 %

Table of Contents

Average Daily Volumes	Year Ended December 31,			Variance		2017-2016	
				2018-2017			
(in thousands of barrels per day) [4]	2018	2017	2016	Volumes	%	Volumes	%
Tariff activities volumes							
Crude oil pipelines (by region):							
Permian Basin [5]	3,732	2,855	2,146	877	31 %	709	33 %
South Texas / Eagle Ford [5]	442	360	284	82	23 %	76	27 %
Central [5]	473	420	394	53	13 %	26	7 %
Gulf Coast	178	349	497	(171)	(49)%	(148)	(30)%
Rocky Mountain [5]	284	393	449	(109)	(28)%	(56)	(12)%
Western	183	184	188	(1)	(1)%	(4)	(2)%
Canada	316	352	381	(36)	(10)%	(29)	(8)%
Crude oil pipelines	5,608	4,913	4,339	695	14 %	574	13 %
NGL pipelines	183	170	184	13	8 %	(14)	(8)%
Tariff activities total volumes	5,791	5,083	4,523	708	14 %	560	12 %
Trucking volumes	98	103	114	(5)	(5)%	(11)	(10)%
Transportation segment total volumes	5,889	5,186	4,637	703	14 %	549	12 %

** Indicates that variance as a percentage is not meaningful.

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

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

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 20 to our Consolidated Financial Statements for additional discussion of such adjustments.

(4) 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.

(5) Region includes volumes (attributable to our interest) from pipelines owned by unconsolidated entities.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment results generated by our tariff and other fee-related activities depend on the volumes transported on the pipeline and the level of the tariff and other fees charged, as well as the fixed and variable field costs of operating the pipeline. As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor. We recognize the allowance volumes collected at fair value.

The following is a discussion of items impacting Transportation segment operating results for the periods indicated.

Table of Contents

Revenues, Purchases and Related Costs, Equity Earnings in Unconsolidated Entities and Volumes. The following table presents variances in revenues, purchases and related costs and equity earnings in unconsolidated entities by region for the comparative periods presented:

(in millions)	Favorable/(Unfavorable) Variance 2018-2017 Revenues	Purchases and Related Costs	Equity Earnings	Favorable/(Unfavorable) Variance 2017-2016 Revenues	Purchases and Related Costs	Equity Earnings
Permian Basin region	$ 284	$ (66)	$ 22	$ 196	$ (22)	$ 30
South Texas / Eagle Ford region	7	—	17	(2)	—	40
Central region	(10)	—	48	—	—	14
Gulf Coast region	(31)	—	—	(22)	—	—
Rocky Mountain region	(32)	—	4	(20)	—	9
Other regions (including trucking and pipeline loss allowance revenue)	54	(5)	(6)	(18)	(7)	2
Total variance	$ 272	$ (71)	$ 85	$ 134	$ (29)	$ 95

Below is a discussion of the significant drivers impacting net revenues and equity earnings in unconsolidated entities for the comparative periods presented:

- Permian Basin region. Total revenues, net of purchases and related costs, increased by approximately $218 million for the year ended December 31, 2018 compared to the year ended December 31, 2017 and by approximately $174 million for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to higher volumes from increased production and our recently completed capital expansion projects. These increases included (i) higher volumes on our gathering systems of approximately 329,000 and 163,000 barrels per day, including our ACC system, which was acquired in February 2017, (ii) higher volumes of approximately 363,000 and 263,000 barrels per day on our intra-basin pipelines and (iii) a volume increase of approximately 185,000 and 283,000 barrels per day on our long-haul pipelines, including our Sunrise pipeline expansion, which was placed in service in the fourth quarter of 2018, as well as our equity interest in BridgeTex discussed further below.

Equity earnings increased in 2018 compared to 2017 primarily due to earnings from our 50% interest in Advantage, which we acquired in April 2017, and from our interest in BridgeTex due to increased volumes. Such favorable variances were partially offset by the impact of our sale of a 30% interest in BridgeTex in the third quarter of 2018.

Equity earnings increased in 2017 compared to 2016 primarily due to earnings from our 50% interest in BridgeTex resulting from higher volumes.

- South Texas / Eagle Ford region. Equity earnings from our 50% interest in Eagle Ford Pipeline LLC was favorably impacted for each of the comparative periods by higher volumes from our Cactus pipeline.

- Central region. The decrease in revenues for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily due to the sale of certain of our Mid-Continent Area System assets in the fourth quarter of 2017, including the sale of a portion of our interest in our Midway pipeline for which our remaining interest is now accounted for under the equity method of accounting. However, such unfavorable results were partially offset by additional movements on our Red River pipeline in 2018.

Revenues for the year ended December 31, 2017 were flat compared to the year ended December 31, 2016, as increased revenues and volumes from the start-up of our Red River pipeline in December 2016 were offset by (i) lower volumes on certain pipelines due to production declines and (ii) volumes shifting to our recently formed joint venture pipelines.

Table of Contents

Equity earnings increased in 2018 compared to 2017 primarily due to earnings from (i) our 50% interest in the Diamond joint venture pipeline, which was placed in service in late 2017, and (ii) our 50% interest in Midway pipeline, which we account for under the equity method of accounting following the sale of a portion of our interest in the pipeline in the fourth quarter of 2017, as discussed above.

Equity earnings increased in 2017 compared to 2016 primarily due to earnings from (i) our 50% interest in STACK, which was formed in mid-2016 and which completed extensions of the joint venture pipeline in 2017, (ii) our 50% interest in Caddo, which placed the joint venture pipeline in service in late 2016, and (iii) our 50% interest in Diamond, which placed the joint venture pipeline in service in late 2017.

- Gulf Coast region. The decrease in revenues for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily due to (i) lower volumes on the Capline pipeline once the Diamond joint venture pipeline was placed in service in late 2017 and (ii) taking the Capline pipeline out of service beginning in the fourth quarter of 2018. We are currently pursuing an opportunity to reverse the flow of the pipeline. See the “Outlook—Outlook for Certain Idled and Underutilized Assets” section below for additional information.

Revenues and volumes decreased for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to the sale of certain of our Gulf Coast pipelines in March and July 2016.

- Rocky Mountain region. The decrease in revenues and volumes for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily due to the sale of certain pipelines and related assets in the fourth quarter of 2017 and the second quarter of 2018, partially offset by higher volumes on certain of our remaining pipelines.

The decrease in revenues in 2017 compared to 2016 was largely driven by (i) lower volumes on certain Salt Lake City area pipelines due to proactively shutting down our Wahsatch pipeline for approximately 30 days during the first quarter of 2017 as a precautionary measure in response to indications of soil movement identified by our monitoring systems, (ii) the sale of certain Bakken and Salt Lake City area pipelines in October 2017 and (iii) the sale of 50% of our investment in Cheyenne in June 2016, subsequent to which it was accounted for under the equity method of accounting.

Equity earnings increased for the year ended December 31, 2017 compared to the year ended December 31, 2016 due to earnings from (i) our 40% investment in Saddlehorn, which began operations in the third quarter of 2016, and (ii) our 50% investment in Cheyenne, as discussed above. Such increases were partially offset by decreased equity earnings from our 35.67% interest in White Cliffs due to lower volumes on the joint venture pipeline.

- Other. The increase in other revenue for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily due to greater loss allowance revenue driven by higher volumes and prices in 2018. The decrease in volumes on our Canadian crude oil pipelines in 2018 compared to 2017 was partially due to the temporary outage of a connecting carrier. Additionally, the impact on revenues from the decrease in volumes was partially offset by increased tariff rates on certain of the pipelines.

Adjustments: Deficiencies under minimum volume commitments, net. Many industry infrastructure projects developed and completed over the last several years were underpinned by long-term minimum volume commitment contracts whereby the shipper, based on an expectation of continued production growth, agreed to either: (i) ship and pay for certain stated volumes or (ii) pay the agreed upon price for a minimum contract quantity.

During 2018, 2017 and 2016, we had net collections for deficiencies under minimum volume commitments resulting in deferred revenues and an increase to Segment Adjusted EBITDA. Such collections in 2018 were partially offset and in 2017 were substantially offset by (i) shippers utilizing credits associated with previous deficiencies or (ii) credits expiring resulting in the recognition of previously deferred revenue.

Field Operating Costs. Field operating costs for the year ended December 31, 2018 compared to the year ended December 31, 2017 were impacted by (i) an increase in power related costs, primarily from temporary sources, resulting from higher volumes, and (ii) increases in performance-based compensation costs. Such increases were partially offset by (i) the sale of assets in the Rocky Mountain region in the fourth quarter of 2017 and the second quarter of 2018 and (ii) the impact of an increase of estimated costs recognized in 2017 associated with the Line 901 incident (which impact our field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above). See Note 18 to our Consolidated Financial Statements for additional information regarding the Line 901 incident.

Table of Contents

The increase in field operating costs for the year ended December 31, 2017 compared to the year ended December 31, 2016 was primarily due to an increase in estimated costs associated with the Line 901 incident (which impact our field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above). The increase in field operating costs was further driven by an increase in power costs resulting from higher volumes and incremental operating costs from the ACC gathering system acquisition in February 2017, partially offset by cost reduction efforts and decreased costs due to the sale of certain Gulf Coast pipelines in March and July 2016.

Segment General and Administrative Expenses. The increase in segment general and administrative expenses for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily driven by an increase in equity-indexed compensation expense due to a smaller impact from the decrease in unit price for the 2018 period compared to the decrease in unit price for the 2017 period as well as shorter service periods for awards outstanding during 2018 compared to 2017. A portion of equity-indexed compensation expense was associated with awards that will or may be settled in common units (which impact our general and administrative expenses but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above). This increase was partially offset by acquisition costs incurred in the 2017 period related to the ACC gathering system acquisition (which impact our segment general and administrative expenses but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above).

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement and/or refurbishment of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The increase in maintenance capital for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily due to increased investment in our integrity management program and an operational tank replacement project.

Facilities Segment

Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services primarily for crude oil, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. The Facilities segment generates revenue through a combination of month-to-month and multi-year agreements and processing arrangements.

The following tables set forth our operating results from our Facilities segment:

Operating Results (1)	Year Ended December 31,			Variance			
				2018-2017		2017-2016	
(in millions, except per barrel data)	2018	2017	2016	$	%	$	%
Revenues	$1,161	$1,173	$1,107	$(12)	(1)%	$66	6%
Purchases and related costs	(17)	(24)	(26)	7	29%	2	8%
Field operating costs	(360)	(350)	(352)	(10)	(3)%	2	1%
Segment general and administrative expenses (2)	(82)	(73)	(68)	(9)	(12)%	(5)	(7)%
Adjustments (3):							
(Gains)/losses from derivative activities	—	4	(2)	(4)	**	6	**
Deficiencies under minimum volume commitments, net	(2)	—	2	(2)	**	(2)	**
Equity-indexed compensation expense	11	4	7	7	**	(3)	**
Net gain on foreign currency revaluation	—	—	(1)	—	**	1	**
Segment Adjusted EBITDA	$711	$734	$667	$(23)	(3)%	$67	10%
Maintenance capital	$100	$114	$55	$(14)	(12)%	$59	107%
Segment Adjusted EBITDA per barrel	$0.48	$0.47	$0.44	$0.01	2%	$0.03	7%

Table of Contents

	Year Ended December 31,			Variance			
				2018-2017		2017-2016	
Volumes (4)	2018	2017	2016	Volumes	%	Volumes	%
Liquids storage (average monthly capacity in millions of barrels)	109	112	107	(3)	(3)%	5	5 %
Natural gas storage (average monthly working capacity in billions of cubic feet) (5)	66	82	97	(16)	(20)%	(15)	(15)%
NGL fractionation (average volumes in thousands of barrels per day)	131	126	115	5	4 %	11	10 %
Facilities segment total volumes (average monthly volumes in millions of barrels) (6)	124	130	127	(6)	(5)%	3	2 %

** Indicates that variance as a percentage is not meaningful.

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

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

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 20 to our Consolidated Financial Statements for additional discussion of such adjustments.

(4) Average monthly volumes are calculated as total volumes for the year divided by the number of months in the year.

(5) The decrease in average monthly working capacity of natural gas storage facilities over the comparative periods was driven by adjustments for (i) the sale of our Bluewater natural gas storage facility in June 2017, (ii) changes in base gas and (iii) the net capacity change between capacity additions from fill and dewater operations and capacity losses from salt creep.

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

The following is a discussion of items impacting Facilities segment operating results for the periods indicated.

Revenues, Purchases and Related Costs and Volumes. Variances in revenues, purchases and related costs and average monthly volumes for the comparative periods were primarily driven by:

- NGL Storage, NGL Fractionation and Canadian Gas Processing. Revenues decreased by $14 million for the year ended December 31, 2018 compared to the year ended December 31, 2017 primarily due to the sale of a natural gas processing facility in the second quarter of 2018 and decreases in fees at certain of our storage and fractionation facilities. These unfavorable variances were partially offset by the favorable impacts of (i) increased volumes and fees associated with placing an additional 1.6 million barrels of NGL storage capacity into service in the second half of 2017 at our Fort Saskatchewan facility and (ii) higher volumetric gains at certain facilities in the 2018 period.

Revenues increased by $99 million for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to contributions from (i) the Western Canada NGL assets we acquired in August 2016, (ii) expansion projects at our Fort Saskatchewan facility, which have increased storage and fractionation capacity, and (iii) increases in fees at certain of our NGL storage and fractionation facilities.

- Crude Oil Storage. Revenues decreased by $16 million for the year ended December 31, 2018 compared to the year ended December 31, 2017 primarily due to the sale of certain of our Bay Area, California terminal assets in December 2017. These lower results were partially offset by higher revenues from increased activity at our Cushing and St.

James terminals.

Table of Contents

Revenues for the year ended December 31, 2017 were relatively flat compared to the year ended December 31, 2016. Higher 2017 revenues from our Cushing terminal driven by increased terminal throughput and capacity expansions of approximately 2 million barrels were offset by (i) decreased utilization at certain of our Southern California terminals and (ii) the sale of certain of our East Coast terminals in April 2016.

- Natural Gas Storage. Revenues, net of purchases and related costs, decreased by $2 million for the year ended December 31, 2018 compared to the year ended December 31, 2017 primarily due to (i) the June 2017 sale of our Bluewater natural gas storage facility, (ii) the absence of a one-time fee recognized during the first quarter of 2017 related to the early termination of a storage contract at our Pine Prairie facility and (iii) increased storage costs incurred to manage customer activity in 2018. These unfavorable impacts were partially offset by the favorable impact of expiring contracts replaced at higher rates and more favorable market conditions for hub services at certain of our natural gas storage facilities.

Revenues decreased slightly for the year ended December 31, 2017 compared to the same 2016 period. Lower results due to the June 2017 sale of our Bluewater natural gas storage facility were largely offset by contributions from higher rates on new contracts replacing expiring contracts and more favorable market conditions for hub services.

- Rail Terminals. Revenues increased by $26 million for the year ended December 31, 2018 compared to the year ended December 31, 2017 primarily due to higher activity at certain of our rail terminals resulting from more favorable market conditions.

Revenues decreased by $26 million for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to lower activity at our U.S. terminals resulting from less favorable market conditions, partially offset by revenues and volumes from our Fort Saskatchewan, Alberta rail terminal that came online in April 2016.

Field Operating Costs. The increase in field operating costs for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily due to an increase in performance-based compensation costs as well as higher personnel costs at our rail terminals as a result of increased activity, partially offset by lower costs due to sales of assets.

The decrease in field operating costs for the year ended December 31, 2017 compared to the same 2016 period due to reduced rail activity, cost reduction efforts and the sales of our Bluewater natural gas storage facility in June 2017 and certain of our East Coast terminals in April 2016. Such decreases were largely offset by an increase in operating costs associated with the Western Canada NGL assets acquired in August 2016 and increased power costs.

Segment General and Administrative Expenses. The increase in segment general and administrative expenses for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily driven by an increase in equity-indexed compensation expense due to a smaller impact from the decrease in unit price for the 2018 period compared to the decrease in unit price for the 2017 period as well as shorter service periods for awards outstanding during 2018 compared to 2017. A portion of equity-indexed compensation expense was associated with awards that will or may be settled in common units (which impact our general and administrative expenses but are excluded from Segment Adjusted EBITDA and thus are reflected as an “Adjustment” in the table above).

Maintenance Capital. For the year ended December 31, 2018 compared to the year ended December 31, 2017, maintenance capital spending decreased primarily due to the impact of higher expenditures related to our integrity management program in 2017 compared to 2018, primarily on assets at our Southern California terminals. Total maintenance costs related to our integrity management program at these terminals decreased by approximately $46 million for the year ended December 31, 2018 compared to the year ended December 31, 2017. This decrease in maintenance capital spending in 2018 compared to 2017 was partially offset by increased costs at our NGL processing facilities located in Western Canada in 2018.

The increase in maintenance capital for 2017 compared to 2016 was primarily due to increased investment in our integrity management program, primarily on assets at our Southern California terminals. Total maintenance costs related to our integrity management program at these terminals increased by approximately $49 million for 2017 compared to 2016.

Table of Contents

Supply and Logistics Segment

Revenues from our Supply and Logistics segment activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes. Generally, our segment results are impacted by (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchases volumes and NGL sales volumes), (ii) the overall strength, weakness and volatility of market conditions and the allocation of our assets among our various risk management strategies and (iii) the effects of competition on our lease gathering and NGL margins. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. 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, market structure and relative fluctuations in market-related indices and regional differentials.

The following tables set forth our operating results from our Supply and Logistics segment:

Operating Results [1]	Year Ended December 31,			Variance 2018-2017		2017-2016	
(in millions, except per barrel data)	2018	2017	2016	$	%	$	%
Revenues	$32,822	$25,065	$19,018	$7,757	31 %	$6,047	32 %
Purchases and related costs	(31,487)	(24,557)	(18,627)	(6,930)	(28)%	(5,930)	(32)%
Field operating costs	(276)	(254)	(292)	(22)	(9)%	38	13 %
Segment general and administrative expenses [2]	(117)	(102)	(108)	(15)	(15)%	6	6 %
Adjustments [3]:							
(Gains)/losses from derivative activities net of inventory valuation adjustments	(518)	(50)	406	(468)	**	(456)	**
Long-term inventory costing adjustments	21	(24)	(58)	45	**	34	**
Equity-indexed compensation expense	14	8	10	6	**	(2)	**
Net (gain)/loss on foreign currency revaluation	3	(26)	10	29	**	(36)	**
Segment Adjusted EBITDA	$462	$60	$359	$402	**	$(299)	(83)%
Maintenance capital	$13	$13	$10	$—	— %	$3	30 %
Segment Adjusted EBITDA per barrel	$0.97	$0.13	$0.85	$0.84	**	$(0.72)	(85)%

Average Daily Volumes [4]	Year Ended December 31,			2018-2017		2017-2016	
(in thousands of barrels per day)	2018	2017	2016	Volume	%	Volume	%
Crude oil lease gathering purchases	1,054	945	894	109	12 %	51	6 %
NGL sales	255	274	259	(19)	(7)%	15	6 %
Supply and Logistics segment total volumes	1,309	1,219	1,153	90	7 %	66	6 %

** Indicates that variance as a percentage is not meaningful.

(1) Revenues and costs include intersegment amounts.

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

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 20 to our Consolidated Financial Statements for additional discussion of such adjustments.

(4) Average daily volumes are calculated as the total volumes for the period divided by the number of days in the period.

Table of Contents

The following table presents the range of the NYMEX West Texas Intermediate benchmark price of crude oil (in dollars per barrel):

	NYMEX WTI Crude Oil Price	
During the Year Ended December 31,	Low	High
2018	$ 43	$ 76
2017	$ 43	$ 60
2016	$ 26	$ 54

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for each of the years presented primarily due to higher crude oil prices and volumes during the comparative periods. Additionally, revenues were impacted by net gains and losses from certain derivative activities during the periods.

Our NGL operations are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on NGL demand and thus our financial performance.

The following is a discussion of items impacting Supply and Logistics segment operating results for the periods indicated.

Segment Adjusted EBITDA and Volumes. The following summarizes the significant items impacting our Supply and Logistics Segment Adjusted EBITDA for the comparative periods:

- Crude Oil Operations. Net revenues from our crude oil supply and logistics operations increased for the year ended December 31, 2018 compared to the year ended December 31, 2017 primarily due to favorable grade differentials, primarily in the Permian Basin and Western Canada. Such favorable impacts more than offset the benefit to the 2017 period of the contango market conditions. See the “Market Overview and Outlook” section below for additional discussion of recent market conditions.

Net revenues from our crude oil supply and logistics operations decreased for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to lower unit margins, largely due to the negative impact from overbuilt infrastructure, underwritten by volume commitments, and the effect of such on differentials, which, in turn, reduced arbitrage opportunities. Such unfavorable impacts were partially offset by the favorable impact of contango market conditions in 2017.

- NGL Operations. Net revenues from our NGL operations increased for the year ended December 31, 2018 compared to the same period in 2017 primarily due to (i) an audit recovery in 2018 related to a profit-sharing arrangement, (ii) lower supply costs at our straddle plants relative to NGL values, (iii) favorable impacts from a wider isobutane/normal butane differential and (iv) modifications made to our contracting strategies in the 2017-2018 heating season.

Net revenues from our NGL operations decreased for the year ended December 31, 2017 compared to the year ended December 31, 2016, largely due to (i) higher supply costs and tighter differentials driven by competition, which more than offset higher sales volume from the Western Canada NGL assets acquired in August 2016, (ii) warmer weather during the first-quarter 2017 heating season and (iii) higher storage and processing fees for the 2017 period, which were largely offset in our Facilities segment results.

• Impact from Certain Derivative Activities, Net of Inventory Valuation Adjustments. The impact from certain derivative activities on our net revenues includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in another period (or the reversal of mark-to-market gains and losses from a prior period), losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable. See Note 13 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities. These gains and losses impact our net revenues but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above.

- Long-Term Inventory Costing Adjustments. Our net revenues are impacted by changes in the weighted average cost of our crude oil and NGL inventory pools that result from price movements during the periods. These costing adjustments related to long-term inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that was needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. These costing adjustments impact our net revenues but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above.

- Foreign Exchange Impacts. Our net revenues are impacted by fluctuations in the value of CAD to USD, resulting in foreign exchange gains and losses on U.S. denominated net assets within our Canadian operations. These gains and losses impact our net revenues but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above.

- Field Operating Costs. The increase in field operating costs for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily driven by higher third-party trucking costs due to an increase in lease gathering volumes and higher fuel costs due to longer hauls and increased volumes.

The decrease in field operating costs for the year ended December 31, 2017 compared to the year ended December 31, 2016 was primarily due to lower trucking costs as pipeline expansion projects were placed into service and lease gathering volumes shifted from trucks to pipelines.

- Segment General and Administrative Expenses. The increase in segment general and administrative expenses for the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily driven by (i) an increase in equity-indexed compensation expense due to a smaller impact from the decrease in unit price for the 2018 period compared to the decrease in unit price for the 2017 period as well as shorter service periods for awards outstanding during 2018 compared to 2017 and (ii) an increase in personnel costs due primarily to general salary increases and employee severance costs associated with personnel reductions. A portion of equity-indexed compensation expense was associated with awards that will or may be settled in common units (which impact our general and administrative expenses but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above).

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense increased for the year ended December 31, 2018 compared to the same period in 2017 largely driven by additional depreciation associated with the completion of various capital expansion projects, partially offset by the impact of asset sales in the Rocky Mountain region in the fourth quarter of 2017 and the second quarter of 2018.

Depreciation and amortization expense increased for the year ended December 31, 2017 compared to the same period in 2016 largely driven by additional depreciation associated with acquisitions and the completion of various capital expansion projects.

See Note 6 to our Consolidated Financial Statements for additional information.

Gains/Losses on Asset Sales and Asset Impairments, Net

Net gains/losses on asset sales and asset impairments reflects a gain for the year ended December 31, 2018 as compared to a loss for the same period in 2017, and was largely driven by (i) gains on 2018 asset sales, primarily in the Rocky Mountain region and including the sale of an undivided joint interest in a capital expansion project in the Permian Basin region, and (ii) the impact of impairments and accelerated depreciation during 2017 associated with certain of our rail and terminal assets, partially offset by smaller net gains from non-core asset sales and joint venture formations.

Table of Contents

Net gains/losses on asset sales and asset impairments reflects a loss for the year ended December 31, 2017 as compared to a gain for the same period in 2016, and was largely driven by the impact of impairments and accelerated depreciation recognized during 2017 associated with certain of our rail and terminal assets, partially offset by smaller net gains from non-core asset sales and joint venture formations.

Gain on Sale of Investment in Unconsolidated Entities

During the third quarter of 2018, we sold a 30% interest in BridgeTex for proceeds of $868 million, resulting in a gain of $200 million. We retained a 20% interest in BridgeTex.

Interest Expense

Interest expense is primarily impacted by:

- our weighted average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith;
- market interest rates and our interest rate hedging activities; and
- interest capitalized on capital projects.

The following table summarizes the components impacting the interest expense variance (in millions, except percentages):

		Average LIBOR	Weighted Average Interest Rate [1]
Interest expense for the year ended December 31, 2016	$467	0.5 %	4.5 %
Impact of borrowings under credit facilities and commercial paper program	17		
Impact of lower capitalized interest	12		
Other	14		
Interest expense for the year ended December 31, 2017	$510	1.1 %	4.4 %
Impact of retirement of senior notes	(71)		
Other	(8)		
Interest expense for the year ended December 31, 2018	$431	1.9 %	4.3 %

(1) Excludes commitment and other fees.

Interest expense decreased for the year ended December 31, 2018 compared to the year ended December 31, 2017 primarily due to a lower weighted average debt balance during the 2018 period, largely resulting from the repayment of an aggregate of $950 million of senior notes in December 2017.

Interest expense increased for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to (i) a higher weighted average debt balance during the 2017 period and (ii) lower capitalized interest in the 2017 period due to fewer capital projects under construction.

See Note 11 to our Consolidated Financial Statements for additional information regarding our debt activities during the periods presented.

Table of Contents

Other Income/(Expense), Net

The following table summarizes the components impacting Other income/(expense), net (in millions):

	Year Ended December 31,		
	2018	2017	2016
Loss on early redemption of senior notes [1]	$ —	$ (40)	$ —
Gains/(losses) related to mark-to-market adjustment of our Preferred Distribution Rate Reset Option [2]	(14)	13	30
Other	7	(4)	3
	$ (7)	$ (31)	$ 33

[1] See Note 11 to our Consolidated Financial Statements for additional information.
[2] See Note 13 to our Consolidated Financial Statements for additional information.

Income Tax Expense

Income tax expense increased for the year ended December 31, 2018 compared to the year ended December 31, 2017 and for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to higher year-over-year income as impacted by fluctuations in derivative mark-to-market valuations in our Canadian operations across the comparative periods.

Outlook

Market Overview and Outlook

2018 marked a year of generally favorable fundamentals supporting our business versus the previous three years of relative cyclical lows. Brent and WTI Crude oil prices were largely constructive for our producer customers throughout the year ranging from a high of $86/$76 to a low of $50/$43, averaging $72/$65, respectively, but ended the year toward the low end of these ranges. 2018 average horizontal rig count in the U.S. increased more than 20% versus 2017, and crude oil production grew in every U.S. basin in which we have a meaningful presence.

In late 2018, as crude oil inventories rose, crude oil prices declined, prompting concerns that the crude oil market was over supplied. In December alone, WTI crude prices dipped below $50 per barrel, Permian Basin wellhead prices dipped below $40 per barrel, OPEC and Russia announced plans to curb oil production by approximately 1.2 million barrels per day in the first half of 2019 and in Canada, the province of Alberta took the unprecedented step of mandating curtailment of crude oil production by approximately 325,000 barrels per day in 2019 (such production limits were relaxed in February 2019 to allow an additional 75,000 barrels per day of production). Although crude oil prices have recovered and regional basis differentials have narrowed, the combination of the previously mentioned factors appears to have induced a level of caution among our producer customers and may result in lower capital investment year-over-year and less production growth than previously forecast.

With respect to the crude oil midstream sector, production growth and limited pipeline take-away capacity caused pipelines in many basins to operate at high levels of utilization during 2018, which was favorable for results in both our Transportation and Supply and Logistics segments. Specifically, regional production increases created concerns regarding pipeline take-away capacity, particularly in the Permian Basin and Western Canada, which in turn caused crude oil location differentials in these areas to widen relative to historical norms. This environment created opportunities for our Supply and Logistics segment to generate additional margin. Entering 2019, regional basis differentials have narrowed, and while we may experience periods of volatility in 2019, we do not expect regional basis differentials to be as wide as they were in 2018 due to mandated production curtailments in Canada and the commissioning of new pipeline takeaway capacity from the Permian Basin in 2019.

Looking forward, we believe the fundamental outlook for the crude oil production in the U.S. to be constructive. Underpinned by technological advancements, and assuming a reasonable crude oil price. U.S. Lower 48 crude oil production is positioned to grow significantly over the next several years, with the Permian Basin representing the most attractive and

Table of Contents

significant growth region. We believe we are well positioned to grow our fee-based businesses as production in the U.S. increases.

Although the fundamental crude oil production growth outlook is favorable, midstream competition remains high, particularly in the crude oil transportation and terminalling businesses, leading to potential infrastructure overbuild in multiple basins in the U.S. An overbuild of crude oil pipelines could result in location differentials being in-line with or below pipeline tariffs (similar to the impact experienced in recent years). Additionally, although our positioning for the next few years remains solid, we expect to experience continued competitive pressures that could negatively impact our Supply and Logistics activities and certain of our legacy pipelines that are not supported by shipper commitments.

With respect to the financial markets for our equity securities, investor sentiment for energy investments appeared to be at a relative low throughout 2018. Capital inflows in the upstream and midstream sectors have been historically low, and stock performance has lagged broader markets. As a result, access to conventional financial markets historically relied upon by master limited partnerships (“MLP”) to finance growth-oriented projects and manage debt levels has been both challenging and limited.

In August 2017, we announced a plan to reduce our leverage and improve our financial flexibility. Since August of 2017, we have completed a combination of actions, including: reducing our distributions to unitholders, issuing approximately $800 million of preferred equity, completing approximately $2 billion of divestitures, and managing our working capital lower, while funding an expanded capital investment program and growing cash flow. The combination of these factors enabled us to reduce total debt since June 2017 by approximately $2 billion and meaningfully improve our leverage metrics. For the foreseeable future, we plan to fund the equity portion of our routine organic growth capital program with cash flow in excess of distributions, while targeting lower leverage and giving us the opportunity to consider increasing distributions to unitholders over time.

However, we can provide no assurance that we will be able to achieve the objectives set forth above or that our efforts will generate targeted results. See Item 1A. “Risk Factors—Risks Related to Our Business.”

Outlook for Certain Idled and Underutilized Assets

During 2015, we shut down Line 901 and a portion of Line 903 in California following the release of crude oil from Line 901 (see Note 18 to our Consolidated Financial Statements for additional information). During the period since these pipelines were idled, we have been assessing potential alternatives in order to return them to operation. Some of the alternatives under consideration could result in incurring costs associated with retiring certain assets or an impairment of some or all of the carrying value of the idled property and equipment, which was approximately $120 million as of December 31, 2018.

As of December 31, 2018, we owned a 54% undivided joint interest in the Capline system, which originates in St. James, Louisiana and terminates in Patoka, Illinois. The construction of new crude oil pipeline infrastructure and the ongoing changing crude oil flows in the United States has resulted in a decline in volumes on the Capline system to levels that cannot sustain operations. Northbound service has been discontinued and the operator is in the process of purging the oil from the system and idling the pipeline. In January 2019, the owners converted their undivided joint interests into a limited liability company and launched a binding open season to solicit shipper interest for a reversal of Capline and the initiation of southbound service on Capline from Patoka, Illinois to St. James, Louisiana and potentially on our Diamond Pipeline and Capline from Cushing, Oklahoma to St. James. If Capline does not secure a sufficient amount of shipper interest to support a reversal of the pipeline system, we could incur costs associated with retiring the system and an impairment of the carrying value of our interest in the Capline system, which was $178 million, exclusive of linefill, as of December 31, 2018.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities as further discussed below in the section entitled "—Cash Flow from Operating Activities," (ii) borrowings under our credit facilities or commercial paper program and (iii) funds received from sales of equity and debt securities. In addition, we may supplement these sources of liquidity with proceeds from our divestiture program, as further discussed below in the section entitled "—Acquisitions, Investments, Expansion Capital Expenditures and Divestitures." Our primary cash requirements include, but are not limited to, (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products, other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders. We generally expect to

Table of Contents

fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities and the sale of assets.

As of December 31, 2018, we had a working capital surplus of $77 million and approximately $2.9 billion of liquidity available to meet our ongoing operating, investing and financing needs, subject to continued covenant compliance, as noted below (in millions):

	As of December 31, 2018
Availability under senior unsecured revolving credit facility (1) (2)	$ 1,434
Availability under senior secured hedged inventory facility (1) (2)	1,382
Subtotal	2,816
Cash and cash equivalents	66
Total	$ 2,882

(1) Amounts outstanding under the PAA commercial paper program reduce available capacity under the facilities. There were no outstanding PAA commercial paper borrowings at December 31, 2018.

(2) Available capacity under the senior unsecured revolving credit facility and the senior secured hedged inventory facility was reduced by outstanding letters of credit of $166 million and $18 million, respectively.

We believe that we have, and will continue to have, the ability to access the commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. In addition, usage of our credit facilities, which provide the financial backstop for our commercial paper program, is subject to ongoing compliance with covenants. As of December 31, 2018, we were in compliance with all such covenants. Also, see Item 1A. “Risk Factors” for further discussion regarding such risks that may impact our liquidity and capital resources.

Cash Flow from Operating Activities

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

Cash flow from operating activities can be materially impacted by the storage of crude oil in periods of a contango market, when the price of crude oil for future deliveries is higher than current prices. In the month we pay for the stored crude oil, we borrow under our credit facilities or commercial paper program (or use cash on hand) to pay for the crude oil, which negatively impacts operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, the level of NGL and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it and we do not rely on borrowings under our credit facilities or commercial paper program to pay for the crude oil. During such market conditions, our accounts payable and accounts receivable generally move in tandem as we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. In periods during which we build inventory, regardless of market structure, we may rely on our credit facilities or commercial paper program to pay for the inventory. In addition, we use derivative instruments to manage the risks associated with the purchase and sale of our commodities. Therefore, our cash flow from operating activities may be impacted by the margin deposit requirements related to our derivative activities. See Note 13 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Net cash provided by operating activities for the years ended December 31, 2018, 2017 and 2016 was approximately $2.6 billion, $2.5 billion and $0.7 billion, respectively, and primarily resulted from earnings from our operations. Additionally, as discussed further below, changes during these periods in our inventory levels and associated margin balances required as part of our hedging activities impacted our cash flow from operating activities.

During 2018, our cash provided by operating activities was favorably impacted by approximately $250 million of cash received for transactions for which the revenue has been deferred pending the completion of future performance obligations. See Note 3 to our Consolidated Financial Statements for additional information. The favorable impact was partially offset by an increase in the volume of crude oil inventory that we held, which was funded from earnings from our operations and proceeds from asset sales.

During 2017, net cash provided by operating activities was positively impacted by decreases in (i) the volume of crude oil inventory that we held and (ii) the margin balances required as part of our hedging activities, both of which had been funded by short-term debt. This was consistent with our plan to reduce our hedged inventory volumes, and the cash inflows associated with these items resulted in a favorable impact on our cash provided by operating activities. However, the favorable effects from such activities were partially offset by higher weighted average prices and volumes for NGL inventory that was purchased and stored at the end of the 2017 period in anticipation of the 2017-2018 heating season.

During 2016, we increased our inventory levels and margin balances required as part of our hedging activities that were funded by short-term debt, resulting in an unfavorable impact on our cash provided by operating activities. Furthermore, cash provided by operating activities as compared to prior periods was unfavorably impacted by the decrease in cash from overall earnings.

Acquisitions, Investments, Expansion Capital Expenditures and Divestitures

In addition to our operating needs discussed above, we also use cash for our acquisition activities and expansion capital projects. Historically, we have financed these expenditures primarily with cash generated by operating activities and the financing activities discussed in "—Equity and Debt Financing Activities" below. In recent years, we have also used proceeds from our divestiture program, as discussed further below. We have made and will continue to make capital expenditures for acquisitions, expansion capital projects and maintenance activities. Also see "—Acquisitions, Capital Projects and Divestitures" for further discussion of such capital expenditures.

Acquisitions. The price of acquisitions includes cash paid, assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year. We did not acquire any assets in 2018. During the years ended December 31, 2017 and 2016, we paid cash of $1.280 billion (net of cash acquired of $4 million), and $282 million (net of cash acquired of $7 million), respectively, for acquisitions.

Divestitures. In 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. During the years ended December 31, 2017 and 2016, we received proceeds of $1.083 billion and $569 million (net of $85 million paid for a remaining interest in a pipeline that was subsequently sold during 2016), respectively. As part of our funding plans for our 2018 expansion capital program, we set a target to raise $700 million through divestitures in 2018. We exceeded this target, receiving proceeds of approximately $1.3 billion during 2018, which included proceeds from the sale of a portion of our interest in BridgeTex in the third quarter of 2018. Excess proceeds above our targeted amounts were used to reduce debt and fund incremental expansion opportunities. We expect to continue these efforts in 2019.

2019 Capital Projects. The majority of our 2019 expansion capital program will be invested in our fee-based Transportation and Facilities segments. We expect that our investments will have minimal contributions to our 2019 results, but will provide growth for 2020 and beyond. Our 2019 capital program includes the following projects as of February 2019 with the estimated cost for the entire year (in millions):

Projects	2019
Permian Basin Takeaway Pipeline Projects	$630
Complementary Permian Basin Projects	285
Other Projects	185
Total Projected 2019 Expansion Capital Expenditures [1]	$1,100

Table of Contents

(1) Amounts reflect our expectation that certain projects will be owned in a joint venture structure with a proportionate share of the project cost dispersed among the partners.

Credit Agreements, Commercial Paper Program and Indentures

At December 31, 2018, we had three primary credit arrangements. These include a $1.6 billion senior unsecured revolving credit facility maturing in 2023, a $1.4 billion senior secured hedged inventory facility maturing in 2021 and a $3.0 billion unsecured commercial paper program that is backstopped by our revolving credit facility and our hedged inventory facility. Additionally, we have two $100 million GO Zone term loans as discussed further below. The credit agreements for our revolving credit facilities (which impact our ability to access our commercial paper program because they provide the financial backstop that supports our short-term credit ratings) and our term loans and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements or indentures would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We were in compliance with the covenants contained in our credit agreements and indentures as of December 31, 2018.

In August 2018, we entered into an agreement for two $100 million GO Zone term loans from the remarketing of our GO Bonds. The GO Zone term loans accrue interest in accordance with the interest payable on the related GO Bonds as provided in the GO Bonds Indenture pursuant to which such GO Bonds are issued and governed. The purchasers of the two GO Zone term loans have the right to put, at par, the GO Zone term loans in July 2023. The GO Bonds mature by their terms in May 2032 and August 2035, respectively. See Note 11 to our Consolidated Financial Statements for additional information.

During the year ended December 31, 2018, we had net repayments on our credit facilities and commercial paper program of $901 million. The net repayments resulted primarily from cash flow from operating activities and proceeds from asset sales, which offset borrowings during the period related to funding needs for capital investments, inventory purchases and other general partnership purposes.

During the year ended December 31, 2017, we had net repayments on our credit facilities and commercial paper program of $654 million. The net repayments resulted primarily from cash flow from operating activities and cash received from our equity activities and asset divestitures, which offset borrowings during the period related to funding needs for (i) acquisition and capital investments, (ii) repayment of our $400 million, 6.13% senior notes in January 2017, (iii) repayment of our $600 million, 6.50% senior notes and our $350 million, 8.75% senior notes in December 2017 and (iv) other general partnership purposes.

During the year ended December 31, 2016, we had net repayments on our credit facilities and commercial paper program of $759 million. The net repayments resulted primarily from cash flow from operating activities as well as cash received from our equity issuances and asset divestitures, which offset borrowings during the period related to funding needs for (i) inventory purchases and related margin balances required as part of our hedging activities, (ii) capital investments, (iii) repayment of our $175 million senior notes in August 2016, (iv) repayment of $642 million of borrowings that we assumed under AAP's senior secured credit agreement in connection with the Simplification Transactions and (v) other general partnership purposes.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding expansion capital projects, acquisitions and refinancing of our debt maturities, as well as short-term working capital (including borrowings for NYMEX and ICE margin deposits) and hedged inventory borrowings related to our NGL business and contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities or commercial paper program and other debt agreements, as well as payment of distributions to our unitholders.

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $1.1 billion of debt or equity securities (“Traditional Shelf”). All issuances of equity securities associated with our continuous offering program have been issued pursuant to the Traditional Shelf. At December 31, 2018, we had approximately $1.1 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (“WKSI Shelf”), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The issuance of our Series B preferred units in October 2017, discussed below, was conducted under our WKSI Shelf.

Table of Contents

Sales of Preferred Units

Series A Preferred Units. In January 2016, we completed the private placement of approximately 61.0 million Series A preferred units at a price of $26.25 per unit resulting in total net proceeds to us, after deducting offering expenses and the 2% transaction fee due to the purchasers and including our 2% general partner's proportionate contribution, of approximately $1.6 billion. We used the net proceeds for capital expenditures, repayment of debt and general partnership purposes.

Commencing on January 28, 2018, the Series A preferred units are convertible at the purchasers' option into common units on a one-for-one basis, subject to certain conditions, and will be convertible at our option in certain circumstances commencing January 28, 2019. See "Distributions to Our Unitholders " below and Note 12 to our Consolidated Financial Statements for additional information regarding the Series A preferred units.

Series B Preferred Units. On October 10, 2017, we issued 800,000 Series B preferred units at a price to the public of $1,000 per unit. We used the net proceeds of $788 million, after deducting the underwriters' discounts and offering expenses, from the issuance of the Series B preferred units to repay amounts outstanding under our credit facilities and commercial paper program and for general partnership purposes, including expenditures for our capital program. See "Distributions to Our Unitholders " below and Note 12 to our Consolidated Financial Statements for additional information regarding the Series B preferred units.

While our Series A and Series B preferred units are considered equity securities and are classified within partners' capital on our Consolidated Balance Sheet, the two out of the three rating agencies that rate us as investment grade only ascribe 50% equity credit with the remaining 50% considered debt for purposes of determining our credit ratings. The remaining rating agency ascribes 100% equity credit while we are rated below investment grade, but will change its approach to 50% equity credit and 50% debt if the rating agency changes our rating to investment grade.

Sales of Common Units. We did not issue any common units during the year ended December 31, 2018. The following table summarizes our issuance of common units during the years ended December 31, 2017 and 2016 (net proceeds in millions):

Year	Type of Offering	Units Issued	Net Proceeds [1] [2]	
2017	Continuous Offering Program	4,033,567	$ 129	[3]
2017	Omnibus Agreement [4]	50,086,326	1,535	[5]
2017 Total		54,119,893	$ 1,664	
2016 Total	Continuous Offering Program	26,278,288	$ 805	[3]

(1) Amounts are net of costs associated with the offerings.

(2) For periods prior to the closing of the Simplification Transactions, the amounts include our general partner's proportionate capital contribution of $9 million during 2016.

(3) We pay commissions to our sales agents in connection with common unit issuances under our Continuous Offering Program. We paid $1 million and $8 million of such commissions during 2017 and 2016, respectively. The net proceeds from these offerings were used for general partnership purposes.

(4) Pursuant to the Omnibus Agreement entered into by the Plains Entities in connection with the Simplification Transactions, PAGP has agreed to use the net proceeds from any public or private offering and sale of Class A shares, after deducting the sales agents' commissions and offering expenses, to purchase from AAP a number of AAP units equal to the number of Class A shares sold in such offering at a price equal to the net proceeds from such offering. The Omnibus Agreement also provides that immediately following such purchase and sale, AAP

will use the net proceeds it receives from such sale of AAP units to purchase from us an equivalent number of our common units.

(5) Includes (i) approximately 1.8 million common units issued to AAP in connection with PAGP's issuance of Class A shares under its Continuous Offering Program and (ii) 48.3 million common units issued to AAP in connection with PAGP's March 2017 underwritten offering. We used the net proceeds we received from the sale of such common units for general partnership purposes, including repayment of amounts borrowed to fund the ACC Acquisition.

Table of Contents

Issuances of Senior Notes. We did not issue any senior unsecured notes during the years ended December 31, 2018 or 2017. During 2016, we issued senior unsecured notes as summarized in the table below (in millions):

Year	Description	Maturity	Face Value	Gross Proceeds[(1)]	Net Proceeds[(2)]
2016	4.50% Senior Notes issued at 99.716% of face value	December 2026	$ 750	$ 748	$ 741

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

(2) Face value of notes less the applicable premium or discount, initial purchaser discounts, commissions and offering expenses. We used the net proceeds from the offering to repay outstanding borrowings under our credit facilities or commercial paper program and for general partnership purposes.

Repayments of Senior Notes. We did not repay any senior unsecured notes during 2018. During 2017 and 2016, we repaid the following senior unsecured notes (in millions):

Year	Description	Repayment Date	
2017	$400 million 6.13% Senior Notes due January 2017	January 2017	(1)
2017	$600 million 6.50% Senior Notes due May 2018	December 2017	(1) (2)
2017	$350 million 8.75% Senior Notes due May 2019	December 2017	(1) (2)
2016	$175 million 5.88% Senior Notes due August 2016	August 2016	(1)

(1) We repaid these senior notes with cash on hand and proceeds from borrowings under our credit facilities and commercial paper program.

(2) In conjunction with the early redemptions of these senior notes, we recognized a loss of approximately $40 million, recorded to "Other income/(expense), net" in our Consolidated Statement of Operations.

Distributions to Our Unitholders

In accordance with our partnership agreement, after making distributions to holders of our outstanding preferred units, we distribute the remainder of our available cash to our common unitholders of record within 45 days following the end of each quarter. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. Our levels of financial reserves are established by our general partner and include reserves for the proper conduct of our business (including future capital expenditures and anticipated credit needs), compliance with law or contractual obligations and funding of future distributions to our Series A and Series B preferred unitholders. Our available cash also includes cash on hand resulting from borrowings made after the end of the quarter.

See Note 12 to our Consolidated Financial Statements for details of distributions paid during the three years ended December 31, 2018. Also, see Item 5. "Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy" for additional discussion regarding distributions.

Distributions to our Series A preferred unitholders. Holders of our Series A preferred units are entitled to receive quarterly distributions, subject to customary anti-dilution adjustments, of $0.525 per unit ($2.10 per unit annualized), which commenced with the quarter ending March 31, 2016. With respect to each quarter ending on or prior to December 31, 2017, we elected to pay distributions on our Series A preferred units in additional Series A preferred units. Beginning with the distribution with respect to the quarter ended March 31, 2018, distributions on our Series A preferred units are paid in cash. Subject to certain limitations, following January 28, 2021, the holders of our Series A preferred units may make a one-time election to reset the distribution rate. See Note 12 to our Consolidated Financial Statements for additional information.

Distributions to our Series B preferred unitholders. Holders of our Series B preferred units are entitled to receive, when, as and if declared by our general partner out of legally available funds for such purpose, cumulative cash distributions, as applicable. Through and including November 15, 2022, holders are entitled to a distribution equal to $61.25 per unit per year,

Table of Contents

payable semiannually in arrears on the 15th day of May and November. See Note 12 to our Consolidated Financial Statements for further discussion of our Series B preferred units, including distribution rates and payment dates after November 15, 2022.

Distributions to our common unitholders. On February 14, 2019, we paid a quarterly distribution of $0.30 per common unit ($1.20 per unit on an annualized basis). The total distribution of $218 million was paid to unitholders of record as of January 31, 2019, with respect to the quarter ending December 31, 2018.

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

Contingencies

For a discussion of contingencies that may impact us, see Note 18 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to ten years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with our counterparties (including giving effect to netting buy/sell contracts and those subject to a net settlement arrangement). We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

The following table includes our best estimate of the amount and timing of these payments as well as other amounts due under the specified contractual obligations as of December 31, 2018 (in millions):

	2019	2020	2021	2022	2023	2024 and Thereafter	Total
Long-term debt and related interest payments (1)	$918	$878	$949	$1,079	$1,599	$ 8,593	$14,016
Leases, rights-of-way easements and other (2)	167	133	109	93	68	341	911
Other obligations (3)	628	195	192	137	123	345	1,620
Subtotal	1,713	1,206	1,250	1,309	1,790	9,279	16,547
Crude oil, NGL and other purchases (4)	7,231	5,262	4,950	4,279	3,931	9,082	34,735
Total	$8,944	$6,468	$6,200	$5,588	$5,721	$ 18,361	$51,282

(1) Includes debt service payments, interest payments due on senior notes and the commitment fee on assumed available capacity under our credit facilities, as well as long-term borrowings under our credit agreements and commercial paper program, if any. Although there may be short-term borrowings under our credit agreements and commercial paper program, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the credit agreements or commercial paper program) in the amounts above. For additional information regarding our debt obligations, see Note 11 to our Consolidated Financial Statements.

(2) Leases are primarily for (i) railcars, (ii) land and surface rentals, (iii) office buildings, (iv) pipeline assets and (v) vehicles and trailers. Includes operating and capital leases as defined by FASB guidance, as well as obligations for rights-of-way easements.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements and (iii) noncancelable commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity method investments. The transportation agreements include approximately $750 million

Table of Contents

associated with an agreement to transport crude oil at posted tariff rates on a pipeline that is owned by an equity method investee, in which we own a 50% interest. Our commitment to transport is supported by crude oil buy/sell agreements with third parties (including Oxy) with commensurate quantities.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2018. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil, NGL and natural gas. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At December 31, 2018 and 2017, we had outstanding letters of credit of approximately $184 million and $166 million, respectively.

Off-Balance Sheet Arrangements

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

Investments in Unconsolidated Entities

We have invested in entities that are not consolidated in our financial statements. None of these entities are borrowers under credit facilities, and we are neither a co-borrower nor a guarantor under any facilities of such entities. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2018 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Advantage Pipeline, L.L.C.	Crude Oil Pipeline	50%	$ 148	$ 2	$ —
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	20%	$ 903	$ 45	$ —
Cactus II Pipeline LLC	Crude Oil Pipeline (1)	65%	$ 695	$ 1	$ —
Caddo Pipeline LLC	Crude Oil Pipeline (2)	50%	$ 127	$ 3	$ —
Cheyenne Pipeline LLC	Crude Oil Pipeline (2)	50%	$ 59	$ 5	$ —
Diamond Pipeline LLC	Crude Oil Pipeline (2)	50%	$ 945	$ 23	$ —
Eagle Ford Pipeline LLC	Crude Oil Pipeline (2)	50%	$ 821	$ 21	$ —
Eagle Ford Terminals Corpus Christi LLC	Crude Oil Terminal and Dock (1)	50%	$ 197	$ 2	$ —
Midway Pipeline LLC	Crude Oil Pipeline (2)	50%	$ 44	$ 7	$ —
Saddlehorn Pipeline Company, LLC	Crude Oil Pipeline	40%	$ 562	$ 21	$ —
Settoon Towing, LLC	Barge Transportation Services	50%	$ 52	$ 6	$ —
STACK Pipeline LLC	Crude Oil Pipeline (2)	50%	$ 158	$ 8	$ —
White Cliffs Pipeline, L.L.C.	Crude Oil Pipeline	36%	$ 507	$ 8	$ —

(1) Asset is currently under construction by the entity and has not yet been placed in service.
(2) We serve as operator of the pipeline.

106

Table of Contents

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

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

• Crude oil

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

• Natural gas

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

• NGL and other

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

See Note 13 to our Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

The fair value of our commodity derivatives and the change in fair value as of December 31, 2018 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil	$ 188	$ 8	$ (7)
Natural gas	(17)	$ 4	$ (4)
NGL and other	99	$ (32)	$ 32
Total fair value	$ 270		

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term commodity prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

107

Table of Contents

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time, we use interest rate derivatives to hedge interest rate risk associated with anticipated interest payments and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. Our variable rate debt outstanding at December 31, 2018, approximately $200 million, was subject to interest rate re-sets of approximately one month. The average interest rate on variable rate debt that was outstanding during the year ended December 31, 2018 was 3.0%, based upon rates in effect during the year. The fair value of our interest rate derivatives was a liability of $7 million as of December 31, 2018. A 10% increase in the forward LIBOR curve as of December 31, 2018 would have resulted in an increase of $22 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2018 would have resulted in a decrease of $22 million to the fair value of our interest rate derivatives. See Note 13 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives was a liability of $9 million as of December 31, 2018. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in a decrease of $21 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in an increase of $21 million to the fair value of our foreign currency derivatives. See Note 13 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Preferred Distribution Rate Reset Option

The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value in our Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including our common unit price, ten-year U.S. treasury rates, default probabilities and timing estimates to ultimately calculate the fair value of our Series A preferred units with and without the Preferred Distribution Rate Reset Option. The fair value of this embedded derivative was a liability of $36 million as of December 31, 2018. A 10% increase or decrease in the fair value would have an impact of $4 million. See Note 13 to our Consolidated Financial Statements for a discussion of embedded derivatives.

Item 8. Financial Statements and Supplementary Data

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

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

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

Applicable SEC rules require an evaluation of the effectiveness of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our DCP as of December 31, 2018, the end of the period covered by this report, and, based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our DCP is effective.

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. "Internal control over financial reporting" is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliab