PART I

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

General

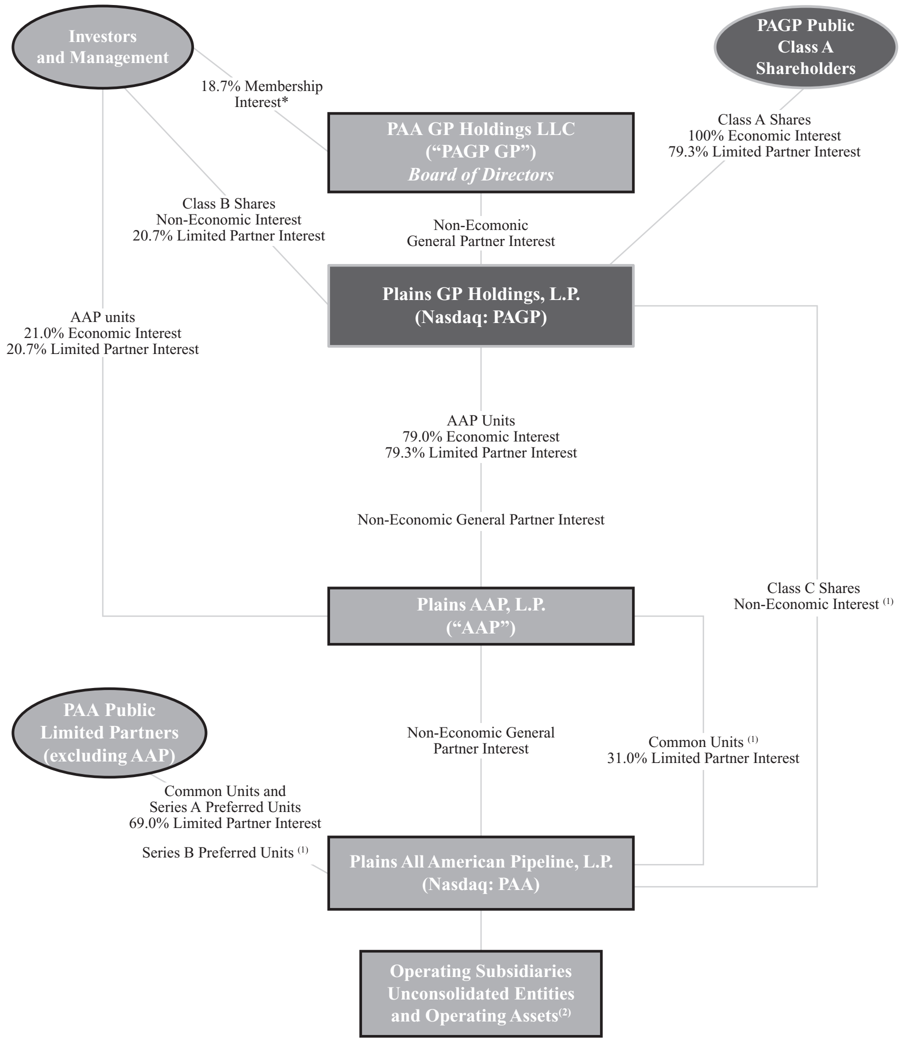
Plains All American Pipeline, L.P. is a publicly traded Delaware limited partnership. Our common units are listed on the Nasdaq Global Select Market ("Nasdaq") under the ticker symbol "PAA." Our business is based on the fundamental thesis that hydrocarbons are essential to the security and advancement of human quality of life and will continue to play a major long-term role in the world economy. We believe that midstream energy infrastructure provides a critical link between energy supply and demand, and is fundamental to the maintenance and advancement of our modern-day standard of living. Acknowledging the need for multiple forms of energy to meet growing world-wide demand, we believe absolute hydrocarbon demand will increase over time, driven by global population growth and a desire to improve quality of life. As a result, we believe that hydrocarbon energy infrastructure will remain critical and valuable.

Our business model integrates large-scale supply aggregation capabilities with the ownership and operation of critical midstream infrastructure systems that connect major producing regions to key demand centers and export terminals. As one of the largest midstream service providers in North America, we own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and natural gas liquids ("NGL") producing basins (including the Permian Basin) and transportation corridors and at major market hubs in the United States and Canada. Our assets and the services we provide are primarily focused on crude oil, NGL and natural gas.

Our operations are conducted directly and indirectly through our primary operating subsidiaries, which comprise 100% of the assets and operations affiliated with Plains and its 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.

Organizational Structure

The diagram below shows our organizational structure as of December 31, 2020 in a summarized format:



* The remaining 81.3% membership interest in PAGP GP is owned by PAGP.

(1) Each Class C share represents a non-economic limited partner interest in PAGP. The number of Class C shares that we own is equal to the number of outstanding common units and Series A Preferred units ("Common Unit Equivalents") that are entitled to vote, pro rata with the holders of PAGP Class A and Class B shares, for the election of eligible PAGP GP directors. The Class C shares function as a "pass-through" voting mechanism through which we vote at the direction of and as proxy for our common unitholders and Series A preferred unitholders in such director elections. Common units held by AAP and Series B preferred units are not entitled to vote in the election of directors.

(2) The Partnership holds (i) direct and indirect ownership interests in consolidated operating subsidiaries including, but not limited to, Plains Marketing, L.P., Plains Pipeline, L.P., Plains Midstream Canada ULC ("PMCULC") and PAA Natural Gas Storage, L.P. and (ii) indirect equity interests in unconsolidated entities including, but not limited to, BridgeTex Pipeline Company, LLC, Cactus II Pipeline LLC, Capline Pipeline Company LLC, Diamond Pipeline LLC, Eagle Ford Pipeline LLC, Eagle Ford Terminals Corpus Christi LLC, Saddlehorn Pipeline Company, LLC, STACK Pipeline LLC, White Cliffs Pipeline, L.L.C. and Wink to Webster Pipeline LLC.

Business Strategy

Our principal business strategy is to provide competitive and efficient midstream infrastructure and logistics services to producers, refiners and other customers. We strive 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 intend to execute our strategy by:

- Focusing on operational excellence, continuous improvement and running a safe, reliable, environmentally and socially responsible operation;
- Using our well positioned network of midstream infrastructure in conjunction with our commercial capabilities to provide market access, flexibility and value chain solutions to our customers, capture market opportunities, address physical market imbalances, mitigate risks and generate sustainable cash flow and margin;
- Optimizing our asset portfolio and operations to maximize returns on invested capital; and
- Pursuing a balanced, long-term financial strategy that is focused on maintaining an investment grade credit profile and enhancing financial flexibility by making disciplined capital allocation decisions.

We believe successful execution of this strategy will enable us to generate sustainable earnings and cash flow, and will position us to reduce leverage and maintain an investment grade credit profile while increasing returns to equity holders over time.

Competitive Strengths

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

- *Strategically located, geographically diverse and interconnected asset base that provides operational flexibility and commercial optionality.* 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 pipeline, rail, barge, truck and storage assets provide our customers and us with significant flexibility and optionality to satisfy demand and balance markets.
- *Full-service integrated model and long-term focus attracts broad, diverse and high-quality customer base that supports sustainable fee-based cash flow generation.* Our strategically located and interconnected asset base enables us to provide our customers with a wide variety of services, including supply aggregation, quality segregation, flow assurance and market access. We focus on building long-term relationships and alignment of interests with our customers. We believe this approach has helped us build a high-quality portfolio of customers and contracts (including long-term, third-party transportation contracts and acreage dedication contracts) that provide long-term volume support for our assets and, in turn, support long-term fee-based cash flow generation from our assets.
- *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 extensive market insight and an understanding of the North American physical crude oil and NGL markets that enables us to provide value chain solutions for our customers.
- *Our supply and logistics activities provide us with the opportunity to realize incremental margins.* We believe the variety of activities executed within our Supply and Logistics segment 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 needed to execute strategic transactions that support our business and financial objectives, including joint ventures, joint ownership arrangements and divestitures.* Since 2016, we have consummated over 10 joint venture and/or joint ownership arrangements and completed over $3 billion of divestitures of non-core assets and/or strategic sales of partial interests

in selected assets. In addition, although acquisitions and investment capital projects are not currently a focus area, the strategic and technical skills needed to complete such transactions are very similar to those needed for other strategic transactions and since our initial public offering, we have completed and integrated over 90 acquisitions with an aggregate purchase price of approximately $13.7 billion, and we have also implemented investment capital projects totaling approximately $16.7 billion.

- *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 experience spanning across all sectors of the energy industry, as well as investment banking, and an average of 14 years with us or our predecessors and affiliates. In addition, through their ownership of common units and grants of phantom units, our management team has a vested interest in our continued success.

Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success is our ability to maintain significant financial flexibility. An important part of our financial strategy is our commitment to generating positive free cash flow after distributions with a continued priority on deleveraging while also prudently increasing cash returned to our unitholders.

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:

- a long-term debt-to-Adjusted EBITDA multiple averaging between 3.0x and 3.5x (See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — Non-GAAP Financial Measures" for our definition of Adjusted EBITDA and a discussion of our selected items that impact comparability and our non-GAAP measures.);
- an average long-term debt-to-total capitalization ratio of approximately 50% or less;
- 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, 2020, our publicly-traded senior notes comprised approximately 97% of our 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 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.

Values and Sustainability

Our Core Values include Safety and Environmental Stewardship, Accountability, Ethics and Integrity and Respect and Fairness. Our Code of Business Conduct sets forth the ways in which these Core Values govern how we conduct ourselves and engage in business relationships. Additional information regarding our Core Values and our commitment to environmental and social responsibility is available in the Sustainability section of our website. See "— Available Information" below.

Ongoing Activities Related to Strategic Transactions

We are continuously engaged in the evaluation of potential transactions that support our current business strategy. While in the past such transactions have included acquisitions and large capital projects, consistent with our current strategic focus on capital discipline, leverage reduction, portfolio optimization and free cash flow generation, we are currently primarily focused on evaluating whether we should (i) sell assets that we regard as non-core or that we believe might be a better fit with the business and/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. Such transactions could involve assets that, if sold or put into a joint venture or joint ownership arrangement, could have a material effect on our financial condition and results of operations.

We typically do not announce a transaction until after we have executed a definitive agreement. However, in certain cases in order to protect our business interests or for other reasons, we may defer public announcement of a transaction until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential transaction can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive agreement may be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future efforts with respect to any such transactions will be successful, and we can provide no assurance that our financial expectations with respect to such transactions will ultimately be realized. See Item 1A. "Risk Factors — Risks Related to Our Business — Divestitures, joint ventures, joint ownership arrangements and acquisitions involve risks that may adversely affect our business."

Joint Venture and Joint Ownership Arrangements

We are party to over 25 joint venture ("JV") and undivided joint interest ("UJI") arrangements with long-term partners throughout the industry value chain spanning across multiple North American basins. We believe that these capital-efficient arrangements provide strategic alignment with long-term industry partners, adding volume commitments to the systems and improving returns.

The following table summarizes our significant JVs as of December 31, 2020:

Entity(1)	Type of Operation	JV Ownership Percentage
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	20%
Cactus II Pipeline LLC	Crude Oil Pipeline(2)	65%
Capline Pipeline Company LLC	Crude Oil Pipeline(3)	54%
Diamond Pipeline LLC	Crude Oil Pipeline(2)	50%
Eagle Ford Pipeline LLC	Crude Oil Pipeline(2)	50%
Eagle Ford Terminals Corpus Christi LLC	Crude Oil Terminal and Dock(2)	50%
Red River Pipeline Company LLC(4)(5)	Crude Oil Pipeline(2)	67%
Saddlehorn Pipeline Company, LLC(4)	Crude Oil Pipeline	30%
STACK Pipeline LLC	Crude Oil Pipeline(2)	50%
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%
Wink to Webster Pipeline LLC(4)	Crude Oil Pipeline	16%

(1) Except for Eagle Ford Terminals, which is reported in our Facilities segment, the financial results from the entities are reported in our Transportation segment.

(2) Asset is operated by Plains.

(3) The Capline pipeline was taken out of service pending the reversal of the pipeline system.

(4) Entity owns a UJI in the crude oil pipeline.

(5) We consolidate Red River Pipeline Company LLC based on control, with our partner's 33% interest accounted for as a noncontrolling interest.

The following table summarizes our significant UJIs as of December 31, 2020, excluding UJIs that are indirectly owned by us through JVs (e.g., Wink to Webster, Saddlehorn and Red River JVs):

Asset	Operating Segment	Type of Operation	UJI Ownership Percentage
Basin Pipeline[1]	Transportation	Crude Oil Pipeline	87%
Empress Processing[2]	Facilities	NGL Facility	50% to 88%
Ft. Saskatchewan NGL Storage and Fractionation[2]	Facilities	NGL Facility	21% to 48%
Western Corridor System[2]	Transportation	Crude Oil Pipeline	21% to 58%
Sarnia NGL Storage and Fractionation[2]	Facilities	NGL Facility	62% to 84%
Sunrise II Pipeline[1]	Transportation	Crude Oil Pipeline	80%

(1) Asset is operated by Plains.

(2) Certain of these assets are operated by Plains.

Acquisitions

Since our initial public offering in 1998, the acquisition of midstream assets and businesses has been an important component of our business strategy. Over the last five years, we completed several acquisitions for an aggregate of approximately $2.0 billion, the majority of which related to an acquisition in 2017. While the pace of our acquisition activity has slowed down in recent years, we continue to selectively analyze and pursue assets and businesses that are strategic and complementary to our existing operations.

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, 2020, we have completed asset sales totaling more than $3 billion.

Investment Capital Projects

Our extensive asset base and our relationships with long-term industry partners across the value chain provide us with opportunities for organic growth through the construction of additional assets that are complementary to, and expand or extend, our existing asset base. Our 2021 capital plan consists of capital-efficient, highly contracted projects that help address industry needs. Substantially all of the capital will be invested in our fee-based Transportation and Facilities segments. The following investment capital projects are included in our 2021 capital plan as of February 2021:

Project	Description	Projected In-Service Date	2021 Plan Amount[(1)] ($ in millions)
Permian Basin Takeaway Pipeline Projects	Primarily includes contributions for our interest in the Wink to Webster JV pipeline	2021 – 2022+	$140
Long-Haul Pipeline Projects (Non-Permian)	Primarily includes contributions for our interests in the Diamond JV pipeline expansion / Capline JV pipeline reversal	1H 2021 – 2022	115
Complementary Permian Basin Projects	Multiple projects to support the Permian Basin takeaway pipeline projects, and to expand/extend our gathering and intra-basin pipelines	1H 2020 – 2021+	85
Selected Facilities Projects	Primarily includes amounts for new connections at our St. James and Cushing facilities and a cavern conversion at our Fort Saskatchewan facility	2021	50
Other Projects		2021 – 2022+	35
Total Projected Investment Capital Expenditures[(1)]			$425

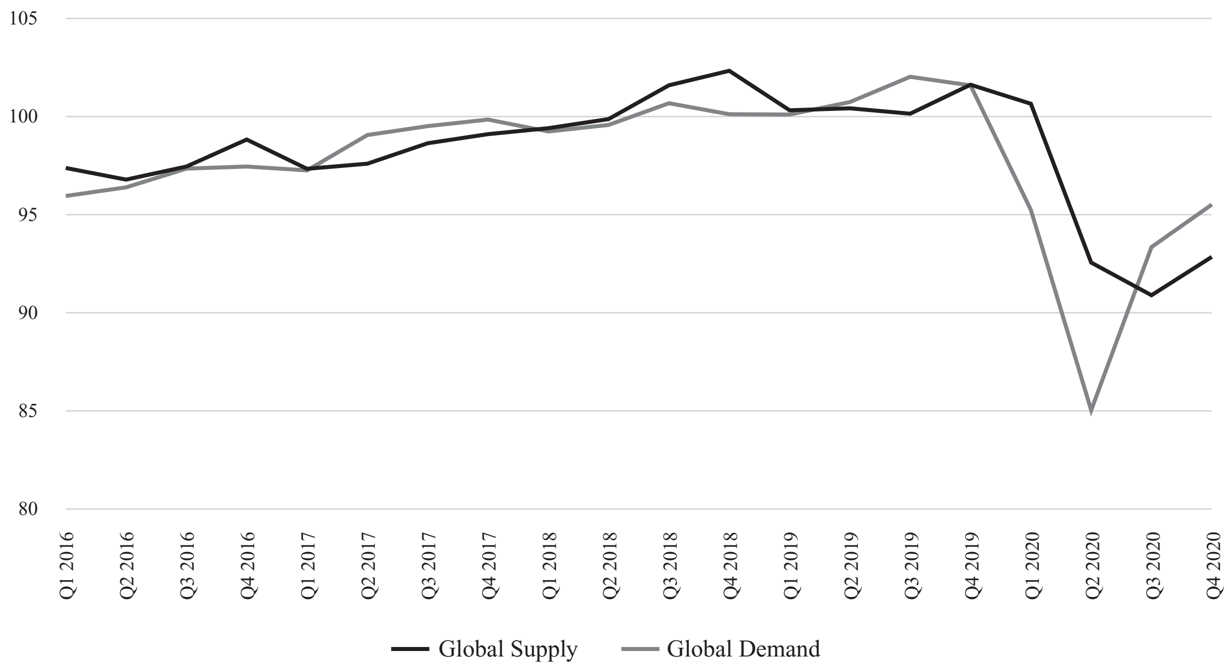
(1) Represents the portion of the total project cost expected to be incurred during the year. Potential variation to current capital costs estimates may result from (i) changes to project design, (ii) final cost of materials and labor and (iii) timing of incurrence of costs due to uncontrollable factors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

Global Petroleum Market Overview and Fundamental Themes

Current Global Petroleum Market Conditions

Crude oil and other petroleum liquids are supplied by producers around the world, including the Organization of Petroleum Exporting Countries ("OPEC") and North American producers, among others. The chart below depicts the relationship between global supply of crude oil and other petroleum liquids and demand since the beginning of 2016:

Global Petroleum and Other Liquids Supply / Demand Balance(1)
(in millions of barrels per day)



(1) Average barrels produced and consumed per quarter.

Source: U.S. Energy Information Administration ("EIA"), Short-Term Energy Outlook, February 2021

In 2019, global demand for crude oil and other petroleum liquids worldwide averaged approximately 101 million barrels per day and since the year 2000 had grown at an average annual rate of approximately 1.0 to 1.5 million barrels per day. The largest drivers of demand growth were increases in population and rising standards of living in developing nations, particularly in Asia.

In 2020, global demand for crude oil and other petroleum liquids worldwide averaged approximately 92 million barrels per day, representing a significant decrease compared to 2019 as a result of the COVID-19 pandemic. As countries around the globe implemented government mandated shutdowns, demand for refined products such as gasoline, diesel and jet fuel significantly decreased resulting in global crude oil and other petroleum liquids demand falling to approximately 81 million barrels per day in April of 2020.

As global demand decreased, inventories began to build and global crude oil prices reached historic lows. Global supply responded in an attempt to rebalance the market as OPEC enacted production cuts, and North American producers shut-in production and greatly reduced capital spending, leading to a 75% reduction in Lower 48 onshore rig count versus the March 2020 peak and an excess of infrastructure in every major North American producing basin.

Both the EIA and OPEC currently forecast that global crude oil demand will recover to or near pre-COVID-19 levels by year end 2021. The global retrenchment of capital in both long-cycle and short-cycle supply combined with natural declines may put a constraint on the ability of producers to meet a meaningful recovery in demand. When demand does recover, there may be a need for incremental supply, and United States short-cycle shale is well positioned to meet this need. In the meantime, we as an industry must focus on rationalization and optimization of the existing infrastructure base while ensuring the ability to serve future growth of both supply and demand. Similar to crude oil, we expect demand for NGL to increase as the world population increases and as the population in developing nations seek to improve their quality of life. In addition, the resource base and the existing logistical infrastructure in North America is well situated to supply a meaningful portion of the expected increase in demand for NGL.

Crude Oil Market Overview

Crude oil is a global commodity that serves as feedstock for many of the world's essential refined products such as transportation fuels (gasoline, diesel, jet fuel) and heating oil, among others. While commodities are typically considered unspecialized, mass-produced and fungible, crude oil is neither unspecialized nor fungible. The crude slate available to North American and world-wide refineries consists of a substantial number of different grades and varieties. 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.

We designed a business model to integrate large-scale supply aggregation capabilities with the ownership and operation of critical infrastructure systems that connect major producing regions (supply) to key demand centers (refineries) and export terminals. 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 supply and demand imbalances change from time to time as a result of a variety of factors, including global demand for exports; regional production declines and/or increases; refinery expansions, modifications and shut-downs; available transportation and storage capacity; and government mandates and related regulatory factors.

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 making it easier to transport and store than ethane. NGL refers to all NGL products including LPG when used in this Form 10-K.

NGL is the primary feedstock for petrochemical facilities that produce many of the everyday consumer products used in the world. 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.

We source NGL supply from field processing plants that are connected to our Cochrane-to-Edmonton ("Co-Ed") system and other third-party pipelines that deliver NGL to our storage and processing assets in the Fort Saskatchewan area in Canada, and large processing plants located near Empress, Canada. These plants straddle the TransCanada pipeline system which is a mainline carrier of pipeline quality gas and primarily extract ethane that feeds local petrochemical facilities, and to a lesser extent extract NGL, which can be processed at our Empress or Sarnia fractionators. We expect NGL supply to grow with increased natural gas production in Western Canada when TransCanada completes the expansion of its mainline system in 2021.

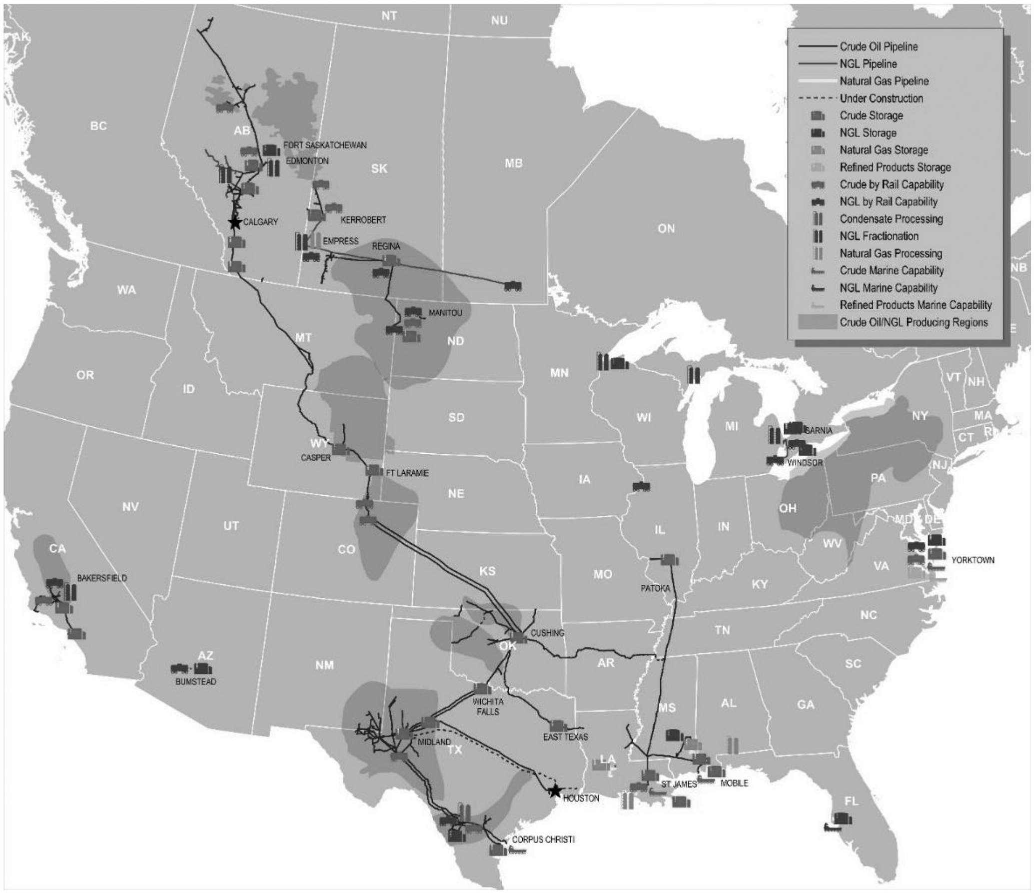
Natural Gas Storage Market Overview

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 a "shock absorber" that balances the market, serving as a source of supply to meet the consumption demands in excess of daily production capacity and a warehouse for gas when production exceeds daily demand.

Overall market conditions for natural gas storage appear to be improving as several fundamental factors are contributing to growth in North American natural gas demand. These factors include (i) increasing exports of LNG from North America, (ii) increasing exports of natural gas to Mexico, (iii) construction of new natural 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. The increase in both supply and demand has created greater opportunities for natural gas storage operations.

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, 2020. 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.

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems and trucks. 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 in entities that own or are developing 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, 2020, 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:

- 18,370 miles of active crude oil and NGL pipelines and gathering systems;
- 35 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput and help maintain product quality segregation; and
- 815 trailers (primarily in Canada).

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, 2020, grouped by geographic location:

Region	Ownership Percentage	Approximate System Miles[1]	2020 Average Net Barrels per Day[2]
			(in thousands)
Crude Oil Pipelines:			
Permian Basin:			
Gathering pipelines	100%	3,265	1,472
Intra-basin pipelines[3]	50% – 100%	815	1,907
Long-haul pipelines[3]	16% – 100%	1,535	1,048
		5,615	4,427
South Texas/Eagle Ford	50% – 100%	830	380
Central	50% – 100%	2,495	379
Gulf Coast	54% – 100%	1,170	134
Rocky Mountain	21% – 100%	3,380	245
Western	100%	545	223
Canada	100%	2,700	294
Crude Oil Pipelines Total		**16,735**	**6,082**
Canadian NGL Pipelines	21% – 100%	1,635	184
Crude Oil and NGL Pipelines Total		**18,370**	**6,266**

(1) Includes total mileage of pipelines in which we own less than 100%.

(2) Represents average daily volumes for the entire year attributable to our interest. Average daily volumes are calculated as the total volumes (attributable to our interest) for the year divided by the number of days in the year. Volumes reflect tariff movements and thus 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 type and 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 from point B to point C would double the pipeline tariff volumes on a particular system versus a single point A to point C movement). As a result, at times, our reported tariff barrel movements may exceed our total capacity.

Crude Oil Pipelines

Our crude oil pipelines are comprised of:

- *gathering pipelines* that move crude oil from wellhead or central battery connections to regional market hubs;
- *intra-basin pipelines* that are used as a hub system creating a significant amount of flexibility by creating connections between regional hub locations; and
- *long-haul pipelines* that move crude oil from (i) regional market hubs to major market hubs such as Cushing, Oklahoma or to export facilities, including our Corpus Christi terminal or (ii) major market hubs to a refinery.

Gathering Pipelines

Permian Basin. We own and operate over 3,200 miles of gathering pipelines in both the Midland Basin and the Delaware Basin that in aggregate represent over 2.5 million barrels per day of pipeline capacity. This gathering capacity includes pipeline capacity that delivers volumes to regional market hubs. Approximately 75% of the capacity of our gathering systems is in the Delaware Basin.

Central. We own and operate gathering pipelines that source crude oil from Western and Central Oklahoma and Southwest Kansas for transportation and delivery into our terminal facilities at Cushing, Oklahoma.

Rocky Mountain. We own and operate pipelines that provide gathering services in the Bakken and the Powder River Basin.

Western. We own and operate a pipeline in the San Joaquin Valley that gathers locally produced crude oil, which is then delivered via our Line 63 pipeline system and/or Line 2000 pipeline for transportation to Los Angeles area refiners.

Canada. We own and operate gathering systems with capacity of approximately 220,000 barrels per day. These gathering systems source crude from truck terminals and pipeline connected facilities to deliver to the Enbridge Mainline system at our Kerrobert and Regina terminals in Saskatchewan.

Intra-basin Pipelines

Permian Basin. We own and operate an intra-basin pipeline system with a capacity of over 2 million barrels per day that connects gathering pipelines 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.

Canada. We own and operate intra-basin pipelines with capacity of approximately 290,000 barrels per day that deliver crude from northern and southern Alberta to the Edmonton, Alberta market hub. These pipelines provide shippers with flexibility to access the Enbridge and TransMountain long-haul pipelines along with the Imperial Oil Refinery. In addition, we have three cross-border pipelines that have the flexibility to move up to approximately 60,000 barrels per day of Canadian crude oil to our Rocky Mountain area long-haul pipelines. These intra-basin pipelines also have the ability to deliver up to approximately 105,000 barrels per day of crude oil to third-party pipelines in the Rocky Mountain region.

Long-haul Pipelines

Permian Basin. We own interests in multiple long-haul pipeline systems that, on a combined basis, represent over 1.5 million barrels per day of currently operational takeaway capacity (net to our ownership interests) out of the Permian Basin to major market hubs in Corpus Christi and Houston, Texas and Cushing, Oklahoma. Below is a description of some of our most significant long-haul pipeline systems within the Permian Basin region.

Permian to Cushing/Mid-Continent

- *Basin Pipeline (Permian to Cushing).* We own an 87% UJI 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.
- *Sunrise II Pipeline.* We operate the Sunrise II Pipeline and, through a UJI arrangement, own 400,000 barrels of the capacity. Our Sunrise II Pipeline transports crude oil from Midland and Colorado City to connecting carriers at Wichita Falls.

Permian to Gulf Coast

- *BridgeTex Pipeline (Permian to Houston).* We own a 20% interest in the legal entity that owns the BridgeTex Pipeline, with two other partners. The pipeline, operated by a subsidiary of Magellan Midstream Partners, L.P., originates at Colorado City, Texas and extends to Houston, Texas. The pipeline has a capacity of 440,000 barrels per day and is capable of receiving supply from both our Basin and Midland South (formerly Sunrise) pipelines.
- *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 to our Eagle Ford joint venture pipeline system.
- *Cactus II Pipeline (Permian to Corpus Christi).* We own a 65% interest in the legal entity that owns the Cactus II Pipeline ("Cactus II"), which we operate. Cactus II is a Permian mainline system that extends directly to the Corpus Christi, Texas market, and has a capacity of 670,000 barrels per day.
- *Wink to Webster Pipeline.* We own a 16% interest in the legal entity that owns the Wink to Webster Pipeline ("W2W Pipeline"), which in turn owns 100% of certain segments of the W2W Pipeline and a 71% UJI in the segment from Midland, Texas to Webster, Texas. The W2W Pipeline originates in the Permian Basin in West Texas and transports crude oil to multiple destinations in the Houston and Galveston market areas. The pipeline system, which is currently in partial service, will provide approximately 1.5 million barrels per day of crude oil capacity (1.1 million barrels per day, net to the UJI interest) and is supported by long-term shipper commitments. Phase one of the pipeline system from Midland, Texas to Webster, Texas is currently in service. Phase two, which increases the pipeline system to 1.5 million barrels per day of capacity, is expected to be in service in the fourth quarter of 2021, at which time long-term shipper commitments will become effective. The third phase of the project, which includes the segments from Wink, Texas to Midland, Texas and from Webster, Texas to Baytown, Texas, has been deferred by the partners until the fourth quarter of 2023.

South Texas/Eagle Ford. We own a 50% interest in the legal entity that owns the Eagle Ford Pipeline through a joint venture with a subsidiary of Enterprise. We serve as the operator of the Eagle Ford Pipeline, which 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 Eagle Ford Pipeline has connectivity to Houston, Texas via a connection with Enterprise's pipeline at Lyssy, Texas.

Central. We own and operate various pipeline systems that extend from our Cushing terminal in Oklahoma to various refineries and/or crude oil hubs. 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 the legal entity that owns the Diamond Pipeline through a joint venture with Valero Energy Corporation ("Valero"). 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. Following the successful 2019 open season on the Capline Pipeline system ("Capline"), the joint venture partners sanctioned an expansion and modest extension of the Diamond Pipeline that will expand its capacity to approximately 420,000 barrels per day, connect it to Capline and facilitate the movement of volumes from Cushing, Oklahoma to St. James, Louisiana.
- *Red River Pipeline (Cushing to Longview).* The Red River Pipeline is an approximately 235,000 barrel per day capacity pipeline that extends from our Cushing Terminal in Oklahoma to Longview, Texas, where it connects with various pipelines. The Red River Pipeline is supported by long-term shipper commitments and we serve as operator. In May 2019, we announced a new joint venture of the Red River Pipeline. Delek Logistics Partners, LP ("Delek") purchased a 33% ownership interest in the new Red River Pipeline Company LLC ("Red River JV") joint venture and we retained a 67% interest. In 2020, we put into service an expansion that enables additional volume pull-through from Cushing, Oklahoma and the Permian to the U.S. Gulf Coast markets, providing additional supply optionality for shippers. In support of this expansion, Delek increased its long-term throughput and deficiency agreement on the Red River Pipeline system from an existing 35,000 barrels per day to

100,000 barrels per day. The Red River JV has an approximate 69% UJI in the pipeline segment from Cushing to Hewitt and owns 100% of the segment of the pipeline extending from Hewitt to Longview.

Rocky Mountain. Our pipeline systems in the Rocky Mountain region provide access to our terminal in Cushing, Oklahoma as well as other major market hubs. We own and operate the Bakken North pipeline system that accommodates bidirectional flow and can move crude oil from the Bakken to the Enbridge Mainline system at Regina, Saskatchewan or from the Enbridge Mainline system to our terminal in Trenton, North Dakota. We own a UJI 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, Oklahoma.

- *Saddlehorn Pipeline*. We own a 30% interest in the legal entity that owns the Saddlehorn Pipeline and, through a UJI arrangement, owns 290,000 barrels per day of capacity in the Saddlehorn Pipeline, which includes a recent expansion of 100,000 barrels per day. The pipeline extends from the Niobrara and Denver-Julesburg ("DJ") Basin to Cushing and is operated by Magellan. The Saddlehorn Pipeline is supported by minimum volume commitments.
- *White Cliffs Pipeline.* We own an approximate 36% interest in the entity that owns the White Cliffs Pipeline system through a joint venture with three other partners. The White Cliffs Pipeline system consists of one crude oil pipeline with approximately 100,000 barrels per day of capacity that extends from the DJ Basin to Cushing, Oklahoma and one NGL pipeline with approximately 90,000 barrels per day of capacity that extends from the DJ Basin to a tie-in location with the Southern Hills Pipeline in Oklahoma. The NGL pipeline is supported by a long-term capacity lease and long-term throughput agreements. A subsidiary of Energy Transfer LP serves as the operator of the pipelines.

Western. We own and operate the Line 63 and Line 2000 pipelines in California. Line 2000 is a mainline system that has the capacity to transport approximately 110,000 barrels per day from the San Joaquin Valley to refineries and terminal facilities in the Los Angeles area. Line 63 is used as a gathering and distribution system. The pipeline gathers crude oil in the San Joaquin Valley for delivery to Line 2000 and local refiners. In the Los Angeles area, the Line 63 distribution lines are used to move crude oil from Line 2000 to local refiners.

Canadian NGL Pipelines

Supply lines. Our supply lines transport NGL from producing locations to downstream processing facilities. Our primary supply system, the Co-Ed NGL pipeline system, has transportation capacity of approximately 70,000 barrels per day and gathers NGL from Southwest and Central Alberta (Cardium, Deep Basin, and Alberta Montney) for delivery to our Fort Saskatchewan, Alberta NGL fractionation facilities. In addition, we own a 50% UJI in a supply line with capacity of approximately 50,000 barrels per day that carries NGL from our Empress, Alberta fractionation facility to cavern storage assets in Kerrobert, Saskatchewan.

Market lines. Market lines are typically used to transport NGL from production locations to further downstream market distribution and storage terminals. We own and operate one market pipeline, the Plains Petroleum Transmission Company ("PPTC") pipeline system, which has approximately 15,500 barrels per day of capacity. The pipeline extends from our Empress, Alberta fractionation facility to our Fort Whyte terminal in Winnipeg, Manitoba. The pipeline also delivers NGL to various terminals and rail loading facilities along the pipeline system.

Hub lines. Hub lines connect regional hub locations, such as processing assets to storage and petrochemical facilities. We own and operate hub lines in eastern Canada with approximately 130,000 barrels per day of capacity that transport propane and butane from our Sarnia, Ontario fractionation facility to our St. Clair, Michigan and Windsor, Ontario storage, rail and truck terminals, as well as third-party locations, and ethane from the Kinder Morgan Utopia pipeline to Nova Chemicals' Corunna petrochemical complex in Sarnia, Ontario.

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 oil, NGL 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, 2020, we owned, operated or employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 75 million barrels of crude oil storage capacity primarily at our terminalling and storage locations;
- approximately 28 million barrels of NGL storage capacity;
- approximately 68 billion cubic feet ("Bcf") of natural gas storage working gas capacity;
- approximately 26 Bcf of owned base gas;
- five 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 206,500 barrels per day, and an isomerization and fractionation facility in California with an aggregate processing capacity of approximately 15,000 barrels per day;
- 22 crude oil and NGL rail terminals located throughout the United States and Canada;
- five marine facilities in the United States; and
- approximately 330 miles of active pipelines that support our facilities assets.

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

Crude Oil Storage and Terminalling Facilities

Our largest crude oil terminals are located in key market hubs, including Cushing, Oklahoma, St. James, Louisiana, Midland, Texas and Patoka, Illinois, and have connectivity to all major inbound and outbound pipelines and other terminals at these hubs.

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.

Our Cushing terminal is connected to our long-haul pipelines from the Permian Basin and Rocky Mountain regions, as well as to our Central region gathering pipelines. Additionally the terminal supplies crude oil to all four of our joint venture, Central region long-haul pipelines.

Our Midland terminal has access to all of our Permian Basin gathering pipelines, either through direct connections, or through our intra-basin pipelines in the Permian Basin. Likewise, the terminal is also either directly connected, or connected through our intra-basin pipelines to all four of our Permian Basin long-haul pipelines.

Our terminals at Corpus Christi, Texas, St. James, Louisiana and Mobile, Alabama all have docks and the capacity to export crude oil. In addition, our St James terminal has a rail unload facility that can move crude from rail cars to pipelines that service local refiners, or to our dock for export.

Our Patoka and St. James terminals are both connected to Capline pipeline, and the terminals will be a receipt and destination facility, respectively, once Capline is placed into service in 2022.

Our crude oil terminals have significant flexibility and operational capabilities, including large-scale multi-grade handling and segregation capabilities and multiple marine transportation loading and unloading capabilities. The table below presents our crude oil storage capacity by location as of December 31, 2020:

Crude Oil Storage Facilities	Total Capacity (MMBbls)
Cushing	27
St. James	15
Patoka	7
Permian Basin Area	8
Mobile and Ten Mile	5
Corpus Christi[(1)]	1
Other[(2)]	12
	75

(1) We own 50% of this storage capacity through our investment in Eagle Ford Terminals Corpus Christi LLC.

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

NGL Storage, Fractionation and Isomerization and Natural Gas Processing Facilities

We have a large integrated network of NGL storage and fractionation and natural gas processing facilities throughout Canada, as well as NGL storage and fractionation facilities in the United States. The tables below present volumes and capacities for these facilities as of December 31, 2020 and our most significant assets are described further below.

NGL Storage Facilities	Total Capacity (MMBbls)
Fort Saskatchewan	11
Sarnia Area	7
Empress Area	4
Other	6
	28

NGL Fractionation and Isomerization Facilities	Ownership Interest	Total Spec Product[(1)] (Bbls/d)	Net Capacity (Bbls/d)
Empress	100%	19,300	23,300
Fort Saskatchewan	21 – 100%	49,100	68,100
Sarnia	62 – 84%	47,200	90,000
Other	82 – 100%	13,200	40,100
		128,800	221,500

Natural Gas Processing Facilities[2]	Ownership Interest	Total Gas Spec Product[1] (Bcf/d)	Gas Processing Capacity (Bcf/d)
United States Gulf Coast Area	100%	0.2	0.3
Empress Area	50 – 88%	2.3	6.0
		2.5	6.3

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

(2) While natural gas processing volumes are presented, they are not indicative of revenues generated by these assets as fees associated with our natural gas processing activities are generally fixed.

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 28 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%. Our Fort Saskatchewan fractionation facility has a design capacity of 85,000 barrels per day and is able to produce up to approximately 50,000 barrels per day of spec propane, butane and condensate. The remaining capacity is used to produce 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 of approximately 17,300 barrels per day.

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, Michigan 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 multiple 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. The Sarnia Fractionator is the largest fractionation plant in Eastern Canada and receives NGL feedstock primarily from the Enbridge pipeline system. The fractionation unit is able to produce approximately 120,000 barrels per day of spec NGL products. Our ownership in the various processing units at the Sarnia Fractionator ranges from 62% to 84%.

Empress Area. We own and/or operate four straddle plants located in the Empress Area, capable of processing up to 6.0 Bcf of natural gas per day, however, supply available to these plants are typically in the 2.5 to 3.5 Bcf per day range. These plants produce approximately 30,000 to 40,000 barrels per day of NGL which can be fractionated at either our Empress or Sarnia fractionators. Our Empress fractionation facility is capable of processing and producing up to 23,300 barrels per day of spec NGL products and is connected to our PPTC pipeline system.

Other. We have a long-term liquids supply and profit sharing contract with a third-party owned straddle plant, near Cochrane, Alberta, with gross processing capacity of approximately 2.5 Bcf per day. NGL produced from this facility are transported on our Co-Ed pipeline system to our Fort Saskatchewan area assets, and then to our Sarnia fractionator via the Enbridge pipeline system. In addition, we own a facility located near Bakersfield, California that provides approximately 15,000 barrels per day of isomerization and fractionation services to producers and customers.

Natural Gas Storage Facilities

We own two natural gas storage facilities with an aggregate commercial working gas capacity of approximately 68 Bcf in service as of December 31, 2020. Our 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 multiple 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.

Condensate Processing Facility

Our Gardendale condensate processing facility is located in La Salle County, Texas. The facility stabilizes condensate that is primarily sourced from our Eagle Ford area gathering systems. The NGL extracted at this facility is delivered to a third-party pipeline that delivers the 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.

Crude Oil Rail Facilities

We own crude oil rail loading facilities located at or near Carr, Colorado; Tampa, Colorado; Manitou, North Dakota; and Kerrobert, Saskatchewan. We own crude oil rail unloading facilities in St. James, Louisiana, Yorktown, Virginia and Bakersfield, California. The table below presents aggregate loading and unloading capacity for these facilities as of December 31, 2020:

	Ownership Interest	Loading Capacity (Bbls/d)	Unloading Capacity (Bbls/d)
Crude Oil Rail Facilities	100%	264,000	350,000

NGL Rail Facilities

We own 18 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 our NGL facilities as well as third-party distribution centers throughout Canada and the United States. 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 table below presents additional information regarding our NGL rail facilities as of December 31, 2020:

	Ownership Interest	Number of Rack Spots	Number of Storage Spots
NGL Rail Facilities	75 – 100%	284	1,589

Supply and Logistics Segment

Our Supply and Logistics segment activities include the purchase, logistics and resale of crude oil and NGL in North America. Through these transactions, we seek to maintain a position that is substantially balanced between purchases and sales and future delivery obligations. The segment owns a significant volume of crude oil and NGL required to conduct our commercial activities. The crude oil and NGL used to support our ongoing commercial activities is classified as long-term assets and linefill or minimum inventory requirements. A summary of the assets employed to support our commercial activities, December 31, 2020, include approximately:

- 16 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;
- 680 trucks and 840 trailers; and
- 6,000 crude oil and NGL railcars.

Our crude oil activities generally include the purchase of crude oil at the wellhead or at central tank batteries typically owned by the crude oil producer. We may also purchase crude oil at market hubs, such as our Cushing terminal, or in-transit in a pipeline. We typically transport our crude oil supply to market hub locations, or directly to refiners using our pipeline or trucking assets and, to a lesser extent, pipelines owned by third parties. We may also optimize the value of our supply by executing exchanges with third parties, where we may exchange qualities of crude oil or the location of our crude oil, and we would either pay or receive a fee for the differential in value for the quality or location of the crude oil. We may use derivative instruments such as the NYMEX futures market to hedge our exposure to crude oil prices. We also hedge the currency differential between the U.S. and Canadian dollar for crude oil purchased on a Canadian dollar basis and sold on a U.S. dollar basis.

Our crude oil supplies are typically sold to refiners, crude oil exporters, traders or other market participants. All crude oil sales arrangements are subject to credit approval. In certain circumstances, where the market value for prompt deliveries of crude oil is discounted to the value for deferred delivery (such conditions are referred to as a "Contango Market") we may store crude oil in tanks included in our Facilities or Transportation segments and use a NYMEX futures contract to hedge the value of the stored crude oil.

Our NGL activities include the purchase of both NGL and the spec components propane and butane ("spec products"). Our NGL supply is typically sourced at our Empress facility, where we acquire the rights to extract NGL from producers and/or shippers of the gas streams that pass through our Empress facility. The extraction rights that we acquire allow us to process that gas at our Empress facility and extract the higher valued NGL from the gas stream. We then purchase natural gas to replace the thermal content attributable to the NGL that was extracted. Our NGL supply at Empress is then either fractionated into spec products at our Empress fractionator, or transported on a third-party pipeline and fractionated into spec products at our Sarnia fractionator. Often times we will use derivative instruments to hedge the differential between natural gas prices and the spec product prices to ensure that we are able to extract and fractionate NGL, and deliver spec products to markets at a profitable margin.

We also acquire spec products from third parties. The majority of the spec products we purchase are at the end ("tailgate") of our Fort Saskatchewan fractionator; however, we may also purchase butane from refiners and propane and/or butane from third-party processors. Some of the spec product we purchase at Fort Saskatchewan is combined into a propane/butane mix and transported on a third-party pipeline to our Sarnia fractionator. The spec products that we own are transported by pipeline, rail or truck and either delivered to one of our storage facilities, or delivered and sold to a third party. Similar to our crude oil activities, spec products may be profitably stored when there is a Contango Market. The value of the stored product is hedged using various derivative instruments.

Credit. Our supply and logistics activities 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. In addition, storing crude oil, NGL or spec products in a Contango Market, or otherwise, requires us to have credit facilities to finance both the purchase of these products in the prompt month as well as margin requirements that may be required for the derivative instruments used to hedge our price exposure.

When we sell crude oil and NGL, we must determine the amount, if any, of credit to be extended to any given customer. 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. 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. See Note 3 to our Consolidated Financial Statements for further discussion of our credit review process and risk management procedures.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2020:

	Volumes (MBbls/d)
Crude oil lease gathering purchases[1]	1,174
NGL sales	144
Supply and Logistics segment total volumes	1,318

(1) Of this amount, approximately 862 MBbls/d were purchased in the Permian Basin.

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

Crude oil, NGL and natural gas commodity prices have historically been very volatile. For example, in the last year, the prompt month NYMEX light, sweet futures contract (commonly referred to as "WTI") price ranged from a low of approximately minus $38 per barrel to a high of approximately $63 per barrel. Similarly, there has also been volatility within the propane and butane markets as seen through the North American benchmark price located at Mont Belvieu, Texas, as well as with the basis differentials between Mont Belvieu prices and prices realized at various market hubs in North America.

While 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, market volatility associated with shifts between demand-driven markets and supply-driven markets or other similar dynamics has in the past, and may in the future create market conditions that are more challenging to our business model. In extended periods of lower crude oil and/or NGL prices, or periods where the supply and demand fundamentals compress regional location differentials, our financial results may be adversely impacted. In such market conditions, product flows on our pipelines in our Transportation segment may be adversely impacted and/or our Supply and Logistics segment may not fully recover its costs on certain transactions. Alternatively, in periods where supply exceeds regional demand and/or pipeline egress, product flows on our pipelines may be favorably impacted and/or our Supply and Logistics segment may be able to capture additional margins. 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 in the "— Risk Management" section below.

Relative contribution levels will vary from quarter-to-quarter due to seasonality, particularly with respect to our NGL activities in our Supply and Logistics segment. However, we expect that (absent material outperformance in our Supply and Logistics segment) our fee-based Transportation and Facilities segments should comprise more than 90% of our aggregate segment results.

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 by using financial derivatives to protect our ability to generate cash flow and optimize asset profitability, 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 13%, 12% and 14% of our revenues for the years ended December 31, 2020, 2019 and 2018, respectively. ExxonMobil Corporation and its subsidiaries accounted for 12%, 12% and 14% of our revenues for the years ended December 31, 2020, 2019 and 2018, respectively. Phillips 66 Company and its subsidiaries accounted for 11% of our revenues for the year ended December 31, 2019. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2020. 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 16 to our Consolidated Financial Statements.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and supply regions and demand for crude oil and NGL by end users. 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 areas where additional infrastructure is being built or has been built to accommodate new or increased production or changing product flows, we face competition in providing the required infrastructure solutions as well as the risk that capacity in the area will be overbuilt for the foreseeable future. As a result of multiple pipeline expansions that have occurred or are being completed in the Permian Basin and other areas, together with meaningful reductions in expected production growth due to COVID-19 impacts, we anticipate competition for uncommitted barrels and contract renewals and extensions will be amplified in the coming years, increasing our contract renewal and customer retention risk.

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.

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 Laws and Regulations — Our operations are 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, executive orders 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.

Health, Safety and Environmental Regulation

General

Our operations involving the storage, treatment, processing and transportation of liquid and gaseous 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, including wildlife. 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 Canada Energy Regulator ("CER"), formerly the National Energy Board, 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 $41 million in 2020. Based on currently available information, our preliminary estimate for 2021 is that we will incur approximately $32 million in expenditures associated with our required pipeline integrity management program. However, 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 $24 million in 2020, and our preliminary estimate for 2021 is that we will incur approximately $18 million of such costs.

PHMSA was reauthorized and the HLPSA was amended in 2011, 2016 and 2020. The regulatory changes precipitated by these actions have increased our cost to operate. For example, in October 2019, PHMSA published three final rules that create or expand reporting, inspection, maintenance and other pipeline safety obligations. Additionally, in the Fiscal Year 2021 Omnibus Appropriations Bill, Congress reauthorized PHMSA through fiscal year 2023 and directed the agency to move forward with several regulatory actions, including the "Pipeline Safety: Class Location Change Requirements" and the "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" proposed rulemakings. Congress has also instructed PHMSA to issue final regulations that will require operators of non-rural gas gathering lines and new and existing transmission and distribution pipeline facilities to conduct certain leak detection and repair programs and to require facility inspection and maintenance plans to align with those regulations.

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 ("EESA") connected to or located in the coastal zone to use best available technologies ("BAT") to reduce the amount of oil released in an oil spill to protect state waters and wildlife. BAT 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 Regulation became effective on October 1, 2020. Milestone dates include: May 1, 2021 — Requests for exemption (for pipelines located outside the Coastal Zone, if the operator can show through spill modeling / risk analysis that a release would not impact the coastal zone portion of an EESA) or deferral (pipeline already employing BAT) from the provisions of this Article shall be submitted to the State Fire Marshal no later than this date; October 1, 2021 — Submittal of Risk analysis, BAT evaluation, and implementation plan for existing pipelines; and April 1, 2023 — Completion of retrofit of existing pipelines with BAT is due. Compliance with these requirements 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 ("API") 653 as the standard for the inspection, repair, alteration and reconstruction of steel above ground 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 $27 million in 2020. For 2021, we have budgeted approximately $30 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 CER 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 continue to implement 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 $69 million in 2020. We are increasing our integrity dig and pipeline replacement projects to ensure safe and reliable operations as we seek to expand volumes on certain of our systems. Our preliminary estimate for 2021 is that we will incur approximately $81 million of costs on such projects.

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, the exclusion for 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.

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. In November 2019, the EPA finalized revisions to the RMP rules, removing requirements related to public disclosure, third-party audits and post-incident root cause analyses, among others. However, several environmental groups and trade unions have challenged the EPA's revised 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 further 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 federal, state and local 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 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 2016, the EPA finalized regulations affecting new, modified and reconstructed sources of air emission in the oil and natural gas sectors (NSPS Subpart OOOOa) that required significant reductions in fugitive methane emissions from certain upstream and midstream oil and gas facilities. We had one natural gas storage facility for which a portion was subject to this regulation. In late 2020, the EPA rescinded the methane requirements of this rule, such that no Plains facility is now affected. There is a possibility that the Biden administration may reverse these changes, and we will continue to monitor these developments. For the period during which our single facility was subject to these requirements, compliance costs were not material.

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. 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 submitted its first compliance report in 2019.

California has also implemented several climate change initiatives via executive order. 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. 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. In late 2020, the governor of California issued an executive order setting targets on the limitation or phase-out of the sale of petroleum-fueled passenger, commercial, and off-road vehicles over the next 15 to 25 years. A number of other states are working to implement zero-emission vehicle requirements or targets. Separately, in October 2020, the Governor of California signed another executive order that establishes a state goal to conserve at least 30% of California's land and coastal waters by 2030 and directs state agencies to implement other measures to mitigate climate change and strengthen biodiversity.

Certain other states where we operate, such as Colorado, have also adopted, or are considering adopting, regulations related to GHG emissions. 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, an increase in the cost of feedstock and products produced by our refinery customers, and a reduced demand for petroleum-based fuels.

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 is currently a signatory to the Paris Agreement. The Paris Agreement is likely to become a significant driver for future potential GHG reduction programs in participating countries, including the United States. President Biden has announced that climate change policy will be a focal point of his administration, and legislative or regulatory initiatives may be developed that may impose additional restrictions on our operations. In January 2021, President Biden signed an executive order directing the Secretary of the Interior to pause new oil and gas leases on public lands and in offshore waters of the United States. The Biden administration could also pursue the imposition of more restrictive requirements for the establishment of pipeline infrastructure or more restrictive GHG emissions limitations for oil and gas facilities. There is also a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding available to the hydrocarbon energy sector. The Federal Reserve recently announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. 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. 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 cost with this reporting requirement is not considered to be material.

In December 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. The Government of Canada has 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 CAD$20 per tonne in 2019 and rise by CAD$10 per year to reach CAD$50 per tonne in 2022) and an output based pricing system ("OBPS") designed to address competitiveness risk for large emitters. However, legislation has been proposed which, if enacted, may increase the carbon prices charged on businesses in jurisdictions subject to the federal program.

In November 2020, the Federal government introduced proposed legislation that would commit the government to reach net-zero GHG emissions by 2050 through setting legally-binding, five-year emissions reduction targets (2030, 2035, 2040 and 2045). The impact of this proposed legislation on PMC operations cannot be determined until the legislation is passed and details of emission reduction targets are disclosed.

In December 2020, the Federal government released a Climate Plan signaling its intent to increase the Federal price on carbon pollution from CAD$30 per tonne to CAD$50 per tonne in 2022 with a further annual increase of CAD$15 per year up to CAD$170 per tonne in 2030. Legislation has not yet been passed for the increase in price on carbon. Costs for compliance with any increase in cost of carbon will be budgeted annually as part of ordinary operating cost processes.

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.

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 GHGs. 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 included Quebec and California. Mandatory participants for the program were responsible for their emissions starting January 1, 2017. PMC's facility at Sarnia was considered a mandatory participant in the program. Compliance with the federal OBPS is not expected to have a material adverse effect on our operations.

In July 2019, the Ontario government implemented the Emissions Performance Standards ("EPS") regulation as a successor program to the repealed GHG cap and trade program. In September 2020, the Federal government accepted the EPS program as equivalent to the OBPS which allows Ontario to move forward with implementing the EPS. Ontario has yet to specify the start date of the EPS and must update regulations to bring the EPS program into effect. Until the EPS comes into force, the PMC Sarnia facility is subject to the OBPS program. Costs for compliance with the OBPS or EPS is budgeted annually and is not expected to have a material effect on operations.

In 2018, the Ontario government introduced an updated Sulphur Dioxide ("SO_2") standard which requires the reduction of SO2 from the current one hour average emission rate of 690 micrograms per cubic meter of air ("µg/m3") to the new one hour standard of 100 µg/m3 by 2023 at industrial facilities. The introduction of this reduction measure requires evaluation of current emissions and may require equipment upgrades at our Sarnia facility. The evaluation process has not been concluded and the impact of the standard is still under review.

Alberta. The Alberta Climate Change and Emissions Management Act provided a framework for managing GHG emissions with the intent of 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. In January 2018, the SGER was replaced with the Carbon Competitive Incentive Regulation ("CCIR") for compliance years 2018 and 2019. In January 2020, the Emissions Management and Climate Resilience Act replaces the Climate Change and Emissions Management Act and the CCIR was replaced with the Technology Innovation and Emissions Reduction ("TIER") regulation. Compliance options under the TIER are similar to those under the previous SGER and CCIR programs such that a GHG fund credit purchase will be required if reduction targets identified under the program are not attained. PMC's Empress VI facility is a mandatory participant under the TIER. For economic reasons, Ft. Saskatchewan and six other PMC facilities have opted in to be a part of the TIER program for 2020. By opting in, the fuel consumption at these asset locations avoid being subject to the federal fuel charge.

Alberta repealed the provincial "Climate Leadership Act" in May 2019 and removed its provincial carbon pricing program. The province is now subject to the federal carbon pricing program. Assets within the TIER program are exempt from the federal carbon pricing program but other fuel consumption as part of operations is subject to the federal levies. The federal fuel charge cost increase has been captured as part of the annual budgeting cycle.

In association with the federal methane reduction targets, the Alberta Energy Regulator amended Directive 60 to outline reduction requirements. New reporting measures and requirements for fugitive emission surveys and methane emission reduction came into force in January 2020. Cost for reporting and completing surveys have been captured within the 2020 and beyond annual 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. Program compliance costs will be passed along to the purchaser. Effective April 1, 2019, the federal carbon pricing program came into effect for provinces that do not have a carbon pricing program in place. This includes Saskatchewan, Manitoba, Ontario and New Brunswick. Program compliance costs will be passed along to the purchaser.

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.

In addition, for over 35 years, the U.S. 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 the NWP program under the CWA. In April 2020, the U.S. District Court for the District of Montana invalidated the 2017 decision by the Corps to reissue the NWP; however, industry groups appealed the decision, and the NWP was reinstated by the U.S. Supreme Court, pending a U.S. Circuit Court appeal process. We anticipate that the appeal will be decided in 2021. Additionally, in response to the vacatur, the Corps has announced a reissuance of the NWP 12 for oil and natural gas pipeline activities, including certain revisions to the conditions for the use of NWP 12; however, the rule has not been officially published and, with President Biden taking office in January 2021, may be subject to further revisions or suspension. While the full extent and impact of the vacatur is unclear at this time, we could face significant delays and financial costs when seeking project approvals from the Corps if we cannot obtain coverage under NWP 12.

In May 2015, the EPA published a final rule that attempted to clarify federal jurisdiction under the CWA over waters of the United States ("WOTUS"). This clarification greatly expanded the definition of WOTUS, thus increasing the jurisdiction of the Corps. Following the issuance of a presidential executive order to review the rule in January 2017, 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 finalized a stay delaying implementation of the 2015 rule for two years. Several states and environmental organizations announced their intent to challenge the stay and any attempt by the EPA and the Corps to rescind or revise the rule. However, on April 21, 2020, the EPA and the Corps announced the 2020 Final Rule concerning the redefinition of WOTUS. The 2020 Final Rule provides the outer bounds 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 Final Rule took effect on June 22, 2020. In general, the 2020 Final Rule resulted in fewer federally regulated waters under the CWA offering a streamlined list of only four clear categories of jurisdictional waters and 12 exclusions. A decrease in mitigation requirements is expected, with traditional wetland states (e.g., Louisiana) and states in the arid west (e.g., Texas) expected to be among the most affected by the new rule. However, legal challenges to this rulemaking are ongoing, and it is possible that the new presidential administration could propose a broader interpretation of WOTUS.

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 U.S. Federal Energy Regulatory Commission ("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. Failure to comply with the requirements of the ICA could result in the imposition of civil or criminal penalties.

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. Pursuant to a December 2020 Order, commencing July 1, 2021, the annual index adjustment for the five year period ending June 30, 2026 will equal the producer price index for finished goods for the applicable year plus an adjustment factor of 0.78%. Rehearing of the December 2020 Order has been requested, and the requests remain pending before FERC. 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. These rates remain regulated by FERC and are subject to challenge or review and modification by FERC consistent with the requirements of the ICA, which requires that tariff rates for liquids pipelines, which include both crude oil pipelines and refined products pipelines, be just and reasonable and non-discriminatory. See Item 1A. "Risk Factors — Risks Related to Laws and Regulations — 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 CER 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 Federal Motor Carrier Safety Association of 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.

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.

Indigenous Protections

Part of our operations cross land that has historically been apportioned to various Native American/ First Nations tribes ("Indigenous Peoples"), who may exercise significant jurisdiction and sovereignty over their lands. Indigenous Peoples may also have certain treaty rights and rights to consultation on projects that may affect such lands. Our operations may be impacted to the extent these tribal governments are found to have and choose to act upon such jurisdiction over lands where we operate. For example, in 2020, the Supreme Court ruled in *McGirt v. Oklahoma* that the Muscogee (Creek) Nation reservation in Eastern Oklahoma has not been disestablished (i.e., officially unrecognized). Prior to the court's ruling, the prevailing view was that all reservations within Oklahoma had been disestablished prior to statehood in 1907. Although the court's ruling indicates that it is limited to criminal law as applied within the Muscogee (Creek) Nation reservation, the ruling has significant potential implications for civil law within the Muscogee (Creek) Nation reservation, as well as other reservations that may similarly be found to not have been disestablished. Later in 2020, state courts in Oklahoma, applying the analysis in *McGirt*, ruled that the Cherokee, Chickasaw, Seminole, and Choctaw reservations likewise had not been disestablished.

On October 1, 2020, the EPA granted approval to the State of Oklahoma under Section 10211(a) of the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005 (the "SAFETE Act") to administer all of the State's existing EPA-approved regulatory programs to Indian Country within the State except: Indian allotments to which Indian titles have not been extinguished; lands that are held in trust by the United States on behalf of any Indian or Tribe; lands that are owned in fee by any Tribe where title was acquired through a treaty with the United States to which such Tribe is a party and that have never been allotted to any citizen or member of such Tribe. The approval extends the State's authority for existing EPA-approved regulatory programs to all lands within the State to which the State applied such programs prior to the U.S. Supreme Court's ruling regarding the Muscogee (Creek) Nation reservation. However, several Tribes have expressed dissatisfaction with the consultation process performed in relation to this approval, and it is possible that EPA's approval under the SAFETE Act could be challenged. Additionally, the SAFETE Act provides that any Tribe in Oklahoma may seek "Treatment as a State" by the EPA, and it is possible that one or more of the Tribes in Oklahoma may seek such an approval from EPA. At this time, we cannot predict how these jurisdictional issues may ultimately be resolved.

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") replacement, the United States-Mexico-Canada Agreement ("USMCA") (July 1, 2020) 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 CER. Violations of these licensing, tariff and tax reporting requirements or failure to provide certifications relating to toxic substances could result in the imposition of significant administrative, civil and criminal penalties. Furthermore, the failure to comply with U.S. federal, state and local tax requirements, as well as Canadian federal and provincial tax requirements, could lead to the imposition of additional taxes, interest and penalties.

Market Anti-Manipulation Regulation

In November 2009, the Federal Trade Commission ("FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to approximately $1.25 million per violation per day, subject to the FTC's annual inflation adjustment. 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 $1.23 million, subject to the CFTC's annual inflation adjustment, 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 $1.31 million per day for each violation, subject to FERC's annual inflation adjustment. FERC also has the authority to order disgorgement of profits from transactions deemed to violate the NGA and the EPAct 2005.

In January 2020, PHMSA finalized a rule regarding the safety of underground natural gas storage facilities, which was published in the Federal Register on February 12, 2020. This rule maintains several elements from the earlier interim rule, incorporating API Recommended Practices 1170 and 1171 in PHMSA regulations; revises the definition of underground natural gas storage facility; and clarifies certain reporting and notification criteria. 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 to cover our operations and properties, and we self-insure certain risks, including gradual pollution, cybersecurity and named windstorms. 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.

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. With respect to our insurance coverage, our policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Additionally, 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 (a) customary liens, restrictions or encumbrances and (b) challenges that we do not regard as material relative to our overall operations. Some of our real property rights may be subject to termination under agreements that provide for one or more of: periodic payments, term periods, renewal rights, abandonment of use, continuous operation requirements, revocation by the licensor or grantor and possible relocation obligations.

Human Capital

General

Our primary human capital management objective is to attract, retain and develop a high quality workforce that will enable us to maintain and enhance a culture that is consistent with our core values of safety and environmental stewardship; ethics and integrity; accountability; and respect and fairness. To support this objective, we seek to attract, reward and support employees through competitive pay, benefits and other programs; develop employees and encourage internal talent mobility to prepare employees for critical roles and leadership positions for the future; facilitate the development of a workplace culture that is diverse, engaging and inclusive; and promote efficiency and a high performance culture by investing in technology and systems and providing tools and resources that enable employees at work.

As a limited partnership, we do not directly have officers and employees. Our operations and activities are managed by Plains All American GP LLC ("GP LLC"), which employs our management and operational personnel (other than our Canadian personnel, who are employed by our subsidiary, PMCULC). As of December 31, 2020, GP LLC and PMCULC employed approximately 4,400 people in North America, of which approximately 3,200 were employed in the U.S. and approximately 1,200 were employed in Canada. Approximately 68% of our workforce (approximately 3,000 employees) are field employees, which includes approximately 880 employees in our trucking division. Our employees are located in 29 states in the U.S. and in 4 provinces in Canada. Approximately 136 employees are covered by five separate collective bargaining agreements, which run through 2023 and 2024.

Health and Safety

Our people are our most valuable asset. We prioritize the health and safety of our employees and we are committed to protecting our employees and conducting our operations in a safe, reliable and responsible manner. We support our commitment to health and safety through extensive education and training and investment in necessary equipment, systems, processes and other resources, and we have a number of safety programs and campaigns that are shared across our operations, such as "Good Catch-Close Call" communications, periodic and situation specific safety stand-downs, lessons learned sharing and stop work authorization for all employees. We also have a number of programs that are focused on employee wellness, including an employee assistance program that has provided free mental and behavioral support for employees during the COVID-19 pandemic. In addition, in order to incentivize performance in the areas of safety and environmental responsibility, our performance-based annual bonus program includes a safety component that is based on year-over-year reductions in our recordable injury rate, and an environmental responsibility component that is tied to year-over-year reductions in the number of federally reportable releases we experience. Since 2017, for each of these metrics, we have improved our performance each year and achieved cumulative three year reductions of more than 50%.

Diversity and Inclusion

We are committed to providing a professional work environment where all employees are treated with respect and dignity and provided with equal opportunities. To that end, we strive to develop a culture of inclusion and diversity in our workforce and aspire to employ a workforce that reflects the diversity of the communities where we operate. As of December 31, 2020, approximately 21% of our overall workforce was female (44% exclusive of field employees), and minorities represented approximately 31% of our U.S. workforce (36% exclusive of field employees).

To support diversity and inclusion efforts at Plains and across the broader industry, we created and sponsor an employee resource group called Cultivating Connections. This group is dedicated to encouraging diversity, inclusion and advancement of women in the industry through networking, mentoring, sharing experiences and ideas, training, and furthering the development of leadership skills. Through Cultivating Connections, an employee mentorship program was also established to encourage professional growth through the development of core competencies.

Training and Leadership Development

We are committed to the continued development of our people. We provide a multitude of training programs covering topics such as field operations, health and safety, regulatory compliance, technical training, management and leadership skills, and professional development. We also operate a number of internal programs at all levels of the workforce that are designed to identify and develop future leaders of the organization. The Board receives reports from senior management on a regular basis regarding the status of succession plans with respect to executive leadership of the company.

Benefits

Our compensation and benefits programs are designed to attract, retain and motivate our employees and to reward them for their services and success. In addition to providing competitive salaries and other compensation opportunities, we offer comprehensive and competitive benefits to our eligible employees including, depending on location, life and health (medical, dental and vision) insurance, prescription drug benefits, flexible spending accounts, parental leave, disability coverage, mental and behavioral health resources, paid time off, retirement savings plan, education reimbursement program and a disaster relief fund.

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 Unitholders" and "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 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. The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all of those interests.

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, 2020, 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, in each case, increased by the applicable inflation adjustment. 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, subject to the exceptions in the Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act," discussed below), 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.

For our 2020 taxable year, the CARES Act increases the 30% adjusted taxable income limitation to 50%, unless we elect not to apply such increase. For purposes of determining our 50% adjusted taxable income limitation, we may elect to substitute our 2020 adjusted taxable income with our 2019 adjusted taxable income, which may result in a greater business interest expense deduction. In addition, unitholders may treat 50% of any excess business interest allocated to them in 2019 as deductible in the 2020 taxable year without regard to the 2020 business interest expense limitations. The remaining 50% of such unitholder's excess business interest is carried forward and subject to the same limitations as other taxable years.

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. While the determination of a partner's "amount realized" generally includes any decrease of a partner's share of the partnership's liabilities, recently issued Treasury regulations provide that the "amount realized" on a transfer of an interest in a publicly traded partnership, such as our common units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner's share of a publicly traded partnership's liabilities. The Treasury regulations further provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2022. For a transfer of interests in a publicly traded partnership that is effected through a broker on or after January 1, 2022, the obligation to withhold is imposed on the transferor's broker. Prospective foreign unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

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 *ir.paalp.com*, our annual reports 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*. Our website includes a significant amount of information about us, including financial and other information that could be deemed material to investors. Investors and others are encouraged to review such information. The information posted on our website is not incorporated by reference into this Annual Report on Form 10-K or any of our other filings with the SEC.

Item 1A. *Risk Factors*

References to the "PAGP Entities" include PAGP GP, PAGP, Plains All American GP LLC, AAP and PAA GP LLC. 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.

Summary of Risk Factors

Risks Related to Our Business

Our business, results of operations, financial condition, cash flows and unit price can be adversely affected by many factors including but not limited to:

- 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;
- pandemics, epidemics or other public health emergencies, such as the recent COVID-19 pandemic;
- competition in our industry, including recontracting and other risks associated with the general capacity overbuild of midstream energy infrastructure in some of the areas where we operate;
- fluctuations in supply and demand, which can be caused by a variety of factors outside of our control;
- natural disasters, catastrophes, terrorist attacks (including eco-terrorist attacks), process safety failures or other events, including pipeline or facility accidents and cyber or other attacks on our electronic and computer systems, could interrupt our operations and/or result in severe personal injury, property damage and environmental damage;
- cybersecurity breaches and other disruptions could compromise our information and operations, and expose us to liability;
- societal and political pressures, including opposition to the development or operation of our pipelines and facilities from various groups;
- the overall forward market for crude oil and NGL, and certain market structures, the absence of pricing volatility and other market factors;
- an inability to fully implement or realize expected returns or other anticipated benefits associated with joint venture and joint ownership arrangements, divestitures, acquisitions and other projects;
- loss of our investment grade credit rating or the ability to receive open credit;
- the credit risk of our customers and other counterparties we transact with in the ordinary course of business activities;
- tightened capital markets or other factors that increase our cost of capital or otherwise limit our access to capital;
- the insufficiency of, or non-compliance with, our risk policies;

- our insurance coverage may not fully cover our losses and we may in the future encounter increased costs related to, and lack of availability of, insurance;
- our current or future debt levels, or inability to borrow additional funds or capitalize on business opportunities;
- changes in currency exchange rates;
- difficulties recruiting and retaining our workforce;
- an impairment of long-term assets;
- significant under-utilization of certain assets due to fixed costs incurred to obtain the right to use such assets;
- 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;
- we do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations;
- our inability to perform all of our obligations under our contracts, which could lead to increased costs; and
- failure to obtain materials or commodities in the quantity and the quality we need, and at commercially acceptable prices, whether due to supply disruptions, tariffs, quotas or other factors.

Risks Related to Laws and Regulations

Our business may be adversely impacted by existing or new laws, executive orders and regulations relating to protection of the environment and wildlife, operational safety, cross-border import/export and tax matters, financial and hedging activities, climate change and related matters.

Risks Inherent in an Investment in Us

Our partnership structure carries inherent risks, including but not limited to:

- cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders;
- cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves;
- 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;
- unitholders may not be able to remove our general partner even if they wish to do so;
- we may issue additional common units without unitholder approval, which would dilute a unitholder's existing ownership interests; and
- conflicts of interest could arise among our general partner and us or the unitholders.

Risks Related to an Investment in Our Debt Securities

Holders of our debt securities are subject to risks including but not limited to:

- 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; and
- 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.

Tax Risks to Common Unitholders and Series B Preferred Unitholders

Our Common Units or Series B Preferred Units are subject to tax risks, which may adversely impact the value of or market for our units and may reduce our cash available for distribution or debt service, including but not limited to:

- our status as a partnership for U.S. federal income tax purposes and not being subject to a material amount of entity-level taxation;
- potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis;
- potential audit adjustments to our income tax returns for tax years beginning after December 31, 2017, by the IRS or state tax authorities;
- IRS or Canada Revenue Agency ("CRA") contests to the federal income tax positions or inter-country allocations we take;
- 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;
- tax-exempt entities and non-U.S. unitholders face unique tax issues from owning our units;
- taxable gain or loss on the disposition of our common units could be more or less than expected;
- unitholders may be subject to limitation on their ability to deduct interest expense incurred by us;
- 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; and
- the tax treatment of income attributable to 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 such income is not eligible for the 20% deduction for qualified publicly traded partnership income.

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.

Drilling activity, crude oil production and benchmark crude oil prices can fluctuate significantly over time. For example, the current COVID-19 pandemic has resulted in a swift and material decline in global crude oil demand and crude oil prices, which has led to a significant reduction of domestic crude oil, NGL and natural gas production, and it is unclear if or when global demand will recover to pre-pandemic levels. This has had an adverse effect on the demand for the midstream services we offer and the commercial opportunities that are available to us. If demand remains depressed or declines further it is likely to have an adverse impact on our financial performance. A turnaround of these adverse macroeconomic factors depends largely on an increase in global demand for crude oil, which will be driven primarily by the extent to which consumer demand and demand for crude oil rebound following the pandemic.

Crude oil prices may also decline due to actions of domestic or foreign oil producers — they may take actions that create an over-supply of crude oil, and decrease benchmark crude oil prices. If producers reduce drilling activity in response to future declines in such prices, reduced capital market access, increased capital raising costs for producers or adverse governmental or regulatory action, it could adversely impact production. 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 long haul 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.

Our business, results of operations, financial condition, cash flows and unit price can be adversely affected by pandemics, epidemics or other public health emergencies, such as the current COVID-19 pandemic.

Our business, results of operations, financial condition, cash flows and unit price can be adversely affected by pandemics, epidemics or other public health emergencies. The current COVID-19 pandemic has caused widespread economic disruption, and resulted in material reductions in demand for crude oil, NGL and other petroleum products, which in turn has resulted in significant 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 many of our assets. Future pandemics, epidemics or other public health emergencies may have greater economic impacts.

As a result of the COVID-19 pandemic, many of our support functions are operating remotely, which presents technical and communication challenges, including increased vulnerability to cybersecurity breaches, risk management oversights or delays in, or disruptions to, communications. In addition, pandemic-related restrictions may adversely impact our ability to operate and maintain our assets, and may adversely impact the supply chain to source goods and services required for our operating activities.

The long term impacts of the COVID-19 pandemic remain highly uncertain and depend on a wide variety of factors that are outside of our control, including the development, deployment and effectiveness of vaccines, treatments and testing protocols; mutations of the virus resulting in increased transmissibility or severity of the disease or decreasing the effectiveness of vaccines or treatments; the capacity of our healthcare systems and public health infrastructure to manage current and future outbreaks; and various political and economic considerations. It is unknown whether consumption of petroleum products will return to pre-COVID levels due to changes in consumer habits or preferences. As a result, we are unable to predict the timing of any such market recovery, including a return to market conditions that are more conducive to an increase in drilling and production activities in the United States and Canada.

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, investment capital projects, acquisitions and joint venture activities. Some of our competitors have capital resources many times greater than ours or control greater supplies of crude oil, natural gas or NGL. In addition, other competitors with significant excess capacity and high financial leverage may attempt to survive and compete by reducing transportation rates to levels approaching variable operating costs, without regard to whether they are generating an acceptable return on their investment. These competitive risks make it more difficult for us to attract new customers and expose us to increased contract renewal and customer retention risk with respect to our existing customers.

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, several new pipeline projects have been placed in service or are currently under construction, and such projects have resulted in, and may contribute to future, 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. In addition, our Supply and Logistics segment is a customer of our Transportation and Facilities segments (See Note 21 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, current and 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, legislative, regulatory or executive actions intended 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. Given that crude oil and petroleum products are global commodities, demand can also be significantly influenced by developments in other countries and markets, particularly in key consumption markets like China. Ultimately, this can lead to a reduction in demand for the services we provide. 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.

Natural disasters, catastrophes, terrorist attacks (including eco-terrorist attacks), process safety failures or other events, including pipeline or facility accidents and cyber or other 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. In addition, our supply and logistics operations include purchasing crude oil and NGL 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. These incidents or 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 profitability, cash flows and 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, critical operating information and data, 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 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 self-insure and thus do not carry insurance specifically for cybersecurity events; however, certain of our insurance policies may allow for coverage of associated damages resulting from such events. If we were to incur a significant liability for which we were not fully insured, or if we incurred costs in excess of reserves established for uninsured or self-insured risks, it could have a material adverse effect on our financial position, results of operations and cash flows.

We may face opposition to the development or operation of our pipelines and facilities from various groups and our business may be subject to societal and political pressures.

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.

Our business plans are based upon the assumption that societal sentiment will continue to enable, and existing regulations will stay intact for, the future development, transportation and use of hydrocarbon-based fuels. Policy decisions relating to the production, refining, transportation and marketing of hydrocarbon-based fuels are subject to political pressures, the negative portrayal of the industry in which we operate by the media and others, and the influence and protests of environmental and other special interest groups. Such negative sentiment regarding the hydrocarbon energy industry could influence consumer preferences and government or regulatory actions, which could, in turn, have an adverse impact on our business.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for hydrocarbon 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 ongoing operations, and consequently could both indirectly affect demand for our services and directly affect our ability to fund construction or other capital projects, as well as properly run our ongoing operations.

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.

We may not be able to fully implement or realize expected returns or other anticipated benefits associated with joint venture and joint ownership arrangements, divestitures, acquisitions and other projects.

We are undertaking, or are participating with various counterparties in, a number of projects that involve the construction of new midstream energy infrastructure assets or the expansion, modification, divestiture or combination 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:

- We may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes;
- Despite the fact that we will expend significant amounts of capital during the construction phase of growth or expansion 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;
- 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 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;
- 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 planned 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.

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.

Our business is dependent on our ability 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 any of such agencies 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.

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

Risks of nonpayment and nonperformance by customers or other counterparties are a significant consideration in our business, and the economic fallout of the COVID-19 pandemic has had an adverse impact on the creditworthiness of many companies in the energy sector. 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.

Divestitures, joint ventures, joint ownership arrangements and acquisitions involve risks that may adversely affect our business.

Our ability to execute our financial strategy is in part dependent on our ability to complete strategic divestitures or sales of interests to strategic partners. If we are unable to successfully complete planned divestitures (due to reduced investment in the energy sector, governmental action, litigation, counterparty non-performance or other factors), it may be more difficult for us to achieve our desired leverage levels, increase returns to equity holders or otherwise accomplish our financial goals. In addition, in connection with our divestitures, we may agree to retain responsibility for certain liabilities that relate to our period of ownership, which could adversely impact our future financial performance.

We are also involved in many strategic joint ventures and other joint ownership arrangements. We may not always be in complete alignment with our joint venture or joint owner counterparties; we may have differing strategic or commercial objectives and may be outvoted by our joint venture partners or we may disagree on governance matters with respect to the joint venture entity or the jointly owned assets. When we enter into joint ventures or joint ownership arrangements we may be subject to the risk that our counterparties do not fund their obligations. In some joint ventures and joint ownership arrangements we may not be responsible for construction or operation of such projects and will rely on our joint venture or joint owner counterparties for such services. Joint ventures and joint ownership arrangements 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 and joint owner projects, it could adversely impact our financial and operating results.

Although our near-term strategy does not include a focus on acquisitions, we have completed a number of acquisitions in the past and may pursue future acquisitions on a selective basis. 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
- 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.

Tightened capital markets or other factors that increase our cost of capital or otherwise limit our access to capital could impair our ability to achieve our strategic objectives.

Any limitations on our access to capital or increase in the cost of that capital could significantly impair the implementation of our 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 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 strategic projects and transactions, 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.

Our risk policies cannot eliminate all risks. In addition, the insufficiency of, or 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. We may also face disruptions to futures markets for crude oil, NGL and other petroleum products, which may impair our ability to execute our commercial or hedging strategies related to the COVID-19 pandemic, future pandemics, epidemics, other public health emergencies or other factors. Margin requirements due to spikes or crashes in commodity prices may require us to exit hedge strategies at inopportune times. 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 insurance coverage may not fully cover our losses and we may in the future encounter increased costs related to, and lack of availability of, insurance.

While we maintain insurance coverage at levels that we believe to be reasonable and prudent, we can provide no assurance that our current levels of insurance will be sufficient to cover any losses that we have incurred or may incur in the future, whether due to deductibles, coverage challenges or other limitations. In addition, 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 several 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 current or future debt levels, or inability to borrow additional funds or capitalize on business opportunities may limit our future financial and operating flexibility.

As of December 31, 2020, the face value of our consolidated debt outstanding was approximately $10.3 billion, consisting of approximately $9.5 billion face value of long-term debt (including senior notes, term loan borrowings and finance lease obligations) and approximately $0.8 billion of short-term borrowings. As of December 31, 2020, we had approximately $2.2 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.

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, 2020, the face value of our consolidated debt was approximately $10.3 billion, of which approximately $9.4 billion was at fixed interest rates and approximately $0.9 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. The COVID-19 pandemic and associated restrictions may also place additional demands on our employees, which may in turn make it more challenging to retain or recruit talented labor. 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.

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

At December 31, 2020, we had approximately $14.6 billion of net property and equipment, $982 million of linefill and base gas, $3.8 billion of investments accounted for under the equity method of accounting and $805 million of net intangible assets capitalized on our balance sheet. GAAP requires an assessment for impairment in certain circumstances, including when there is an indication that the carrying value of property and equipment may not be recoverable. If we were to determine that any of our property and equipment, linefill and base gas, 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 Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates" for additional discussion of our accounting policies and use of estimates associated with impairments. During the year ended December 31, 2020, we recognized goodwill impairment losses of $2.5 billion and non-cash impairment charges of approximately $914 million related to the write-down of certain pipeline and other long-lived assets, certain of our investments in unconsolidated entities, and assets upon classification as held for sale. See Note 6, Note 7, Note 8 and Note 9 to our Consolidated Financial Statements for additional information regarding these impairments.

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.

Significant under-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. Significant under-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.

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. Additionally, parts of our operations cross land that has historically been apportioned to various Native American/First Nations tribes, who may exercise significant jurisdiction and sovereignty over their lands. For more information, see our regulatory disclosure entitled "Indigenous Protections." 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 or commodities in the quantity and the quality we need, and at commercially acceptable prices, whether due to supply disruptions, 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.

Our business also depends on having access to significant amounts of electricity and other commodities. If we are unable to obtain commodities sufficient to operate and maintain our assets, it could materially and adversely affect our business.

The COVID-19 pandemic has caused widespread supply chain disruptions, which may make it more challenging to obtain sufficient quantities of high quality materials at acceptable prices and in a timely manner. If we are unable to source such materials, 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 Related to Laws and Regulations

Our operations are 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, executive orders 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. 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. For example, President Biden campaigned on several initiatives to address environmental concerns. Following the election of President Biden and a Democratic majority in both houses of Congress, it is possible that our operations, and those of our customers, may be subject to greater environmental regulations, particularly with regard to hydraulic fracturing, permitting, and GHG emissions. Any new laws, executive orders 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 investment 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, Congress, through the 2021 Fiscal Year Omnibus Appropriations Bill, directed PHMSA to move forward with several regulatory actions. For more information, please see our regulatory disclosure entitled "Pipeline Safety/Integrity Management." 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 19 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 and our interstate natural gas storage facilities subject to FERC regulation under the NGA, 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. Under certain circumstances, the FERC could limit our ability to set our natural gas storage rates at market-based rates and could order us to reduce our rates for natural gas storage service or require the payment of refunds to our storage customers.

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.

Our Canadian pipelines are subject to regulation by the CER and by provincial authorities. Under the Canadian Energy Regulator Act, the CER 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 CER found the rates or terms of service relating to such pipeline to be unjust or unreasonable or unjustly discriminatory, the CER 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. Furthermore, Presidential Permits that allow cross-border movements of crude oil may be revoked or terminated at any time.

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 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 January 2020, 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 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, executive orders and regulatory initiatives relating to hydraulic fracturing or other hydrocarbon development 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 and there have been a variety of legislative and regulatory proposals to prohibit, restrict, or more closely regulate various forms of hydraulic fracturing; for example, the Governor of California signed an executive order in which he announced plans to ask the state legislature to promulgate legislation banning the issuance of new hydraulic fracturing permits by 2024. In January 2021, President Biden signed an executive order directing the Secretary of the Interior to pause new oil and gas leases on public lands and in offshore waters of the United States. These actions, as well as any other legislation, executive orders 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.

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. However, President Biden has previously stated that one of his administration's climate change goals is to achieve a 100% clean energy economy and net-zero emissions by 2050 at the national level; however, we cannot predict the degree to which this plan may be successfully implemented, what initiatives may be promulgated to facilitate it, or the degree to which it may impact our operations. 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 supply of or demand for oil and natural gas that operators, some of whom are our customers, produce and could thereby reduce demand for our midstream services. For more information, see our regulatory disclosure entitled "Climate Change Initiatives."

Moreover, activists concerned about the potential effects of climate change have directed their attention at sources of funding for hydrocarbon 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 hydrocarbon-intensive activities. Separately, activists may also pursue other means of curtailing oil and gas operations, such as through litigation; several suits have been filed in recent years claiming that oil and gas companies are responsible for climate harm due to their production and/or marketing of hydrocarbons or that oil and gas companies have known about the adverse effects of climate change but failed to adequately disclose those impacts to their investors or consumers. While we cannot predict the outcomes of such activities, 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.

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.

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 66⅔% of our outstanding units (including units held by our general partner or its affiliates). Because AAP owns approximately 34% 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;
- the PAGP GP Board is composed of three classes of directors, which limits our unitholders' ability to make significant changes to the board in any given year; 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 Nasdaq 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 Nasdaq 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 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.

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.

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, 2020, the face value of our total outstanding long-term debt was approximately $9.5 billion, and the face value of our total outstanding short-term debt was approximately $0.8 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.

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

In addition, several states have been 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 units may be modified by administrative, legislative or judicial changes or differing interpretations at any 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 proposals that would eliminate our ability to qualify for partnership tax treatment.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. 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 partnership in the future.

Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be retroactively applied 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 changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our 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 units.

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.

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. While the determination of a partner's "amount realized" generally includes any decrease of a partner's share of the partnership's liabilities, recently issued Treasury regulations provide that the "amount realized" on a transfer of an interest in a publicly traded partnership will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner's share of a publicly traded partnership's liabilities. The Treasury regulations further provide that withholding on a transfer of an interest in a publicly traded partnership will not be imposed on a transfer that occurs prior to January 1, 2022, and after that date, if effected through a broker, the obligation to withhold is imposed on the transferor's broker. Prospective foreign unitholders should consult their tax advisors regarding the impact of these rules on an investment in our units.

Tax Risks to Common Unitholders

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 these 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 15 for additional information regarding CRA challenge of intercompany transactions.

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 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 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, subject to the exceptions in the CARES Act, 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 to the extent such depreciation, amortization, or depletion is not capitalized into cost of goods sold with respect to inventory.

For our 2020 taxable year, the CARES Act increases the 30% adjusted taxable income limitation to 50%, unless we elect not to apply such increase. For purposes of determining our 50% adjusted taxable income limitation, we may elect to substitute our 2020 adjusted taxable income with our 2019 adjusted taxable income, which may result in a greater business interest expense deduction. In addition, unitholders may treat 50% of any excess business interest allocated to them in 2019 as deductible in the 2020 taxable year without regard to the 2020 business interest expense limitations. The remaining 50% of such unitholder's excess business interest is carried forward and subject to the same limitations as other taxable years.

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. Tax-exempt entities 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.

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.

For taxable years beginning after December 31, 2017 and ending on or before December 31, 2025, an individual unitholder is generally allowed 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 income attributable to 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 such income is not eligible for the 20% deduction for qualified publicly traded partnership income.

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. A holder of our Series B Preferred Units could recognize taxable income from the accrual of such income 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 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 will be eligible for the 20% deduction for qualified publicly traded partnership income, Treasury Regulations provide that income attributable to a guaranteed payment for the use of capital is not eligible for the 20% deduction for qualified business income. As a result, income attributable to a guaranteed payment for use of capital recognized by holders of our Series B Preferred Units is not eligible for the 20% deduction for qualified business income.

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 19 to our Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 4. *Mine Safety Disclosures*

Not applicable.