PART II

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

Market Information, Holders and Distributions

Our common units are listed and traded on The Nasdaq Global Select Market under the symbol "PAA." As of February 22, 2022, there were 705,043,477 common units outstanding and approximately 95,000 record holders and beneficial owners (held in street name).

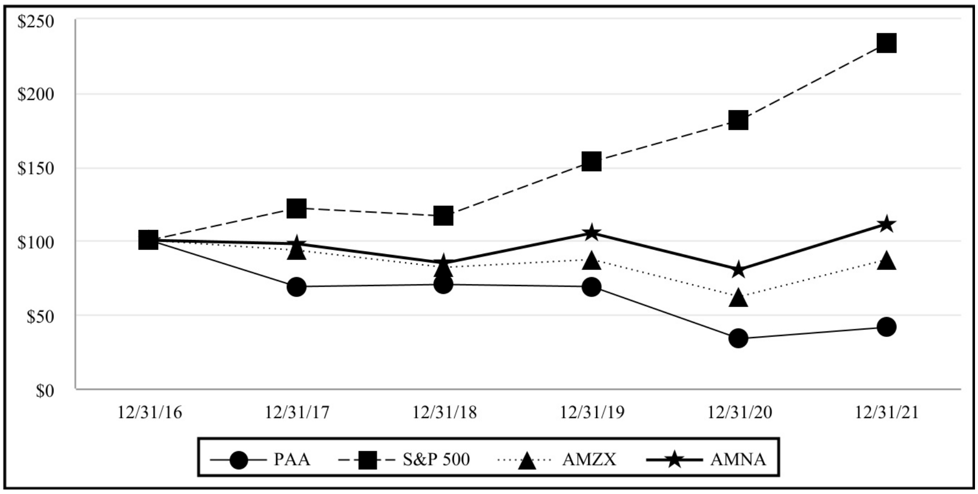
The following table presents cash distributions per common unit pertaining to the quarter presented, which were declared and paid in the following calendar quarter (see the "Cash Distribution Policy" section below for a discussion of our policy regarding distribution payments):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2021	$ 0.18	$ 0.18	$ 0.18	$ 0.18
2020	$ 0.18	$ 0.18	$ 0.18	$ 0.18

Our common units are also used as a form of compensation to our employees and PAGP GP directors. See Note 18 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Performance Graph

The following graph compares the total unitholder return performance of our common units with the performance of: (i) the Standard & Poor's 500 Stock Index ("S&P 500"), (ii) the Alerian MLP Index ("AMZX") and (iii) the Alerian Midstream Energy Index ("AMNA"). The AMZX is a composite of the most prominent energy master limited partnerships that provides investors with a comprehensive benchmark for this asset class. The AMNA is a broad-based composite of North American energy infrastructure companies that provides investors with a comprehensive benchmark for this asset class. We have elected to include the AMNA in addition to the AMZX in this year's performance graph because we believe that a comparison of our performance to each of these industry indices is useful to investors. The graph assumes that $100 was invested in our common units and each comparison index beginning on December 31, 2016 and that all distributions were reinvested on a quarterly basis.



	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021
PAA	$ 100.00	$ 68.66	$ 70.27	$ 68.67	$ 33.77	$ 41.26
S&P 500	$ 100.00	$ 121.83	$ 116.49	$ 153.17	$ 181.35	$ 233.41
AMZX	$ 100.00	$ 93.48	$ 81.87	$ 87.24	$ 62.21	$ 87.20
AMNA	$ 100.00	$ 97.59	$ 84.62	$ 104.97	$ 80.45	$ 111.35

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

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

The following table summarizes our equity repurchase activity during the fourth quarter of 2021:

	Total Number of Common Units Purchased	Average Price Paid per Common Unit (1)	Total Number of Common Units Purchased as Part of Publicly Announced Program (2)	Approximate Dollar Value of Common Units that may yet be purchased under the Program (2)
November 1, 2021 - November 30, 2021	3,384,873	$ 10.64	3,384,873	$ 296,769,608
December 1, 2021 - December 31, 2021	2,759,407	$ 9.06	2,759,407	$ 271,824,798

(1) Average price paid per common unit includes costs associated with the repurchases.

(2) In November 2020, the board of directors of PAA GP Holdings LLC ("PAGP GP") approved a $500 million common equity repurchase program (the "Program"), which authorizes the repurchase from time to time of up to $500 million of our common units and/or PAGP Class A shares via open market purchases or negotiated transactions conducted in accordance with applicable regulatory requirements. No time limit has been set for completion of the Program, and the Program may be suspended or discontinued at any time. The Program does not obligate us or PAGP to acquire a particular number of common units or PAGP Class A shares. Any common units or Class A shares that are repurchased will be canceled. No PAGP Class A shares were repurchased during the periods presented. The common units repurchased under the Program during the periods presented were cancelled immediately upon acquisition.

Cash Distribution Policy

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

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

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

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

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

Item 6. Reserved

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

Introduction

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

Our discussion and analysis includes the following:

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

Executive Summary

Company Overview

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 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 and NGL.

Segment Changes

During the fourth quarter of 2021, we reorganized our historical operating segments: Transportation, Facilities and Supply and Logistics into two operating segments: Crude Oil and Natural Gas Liquids ("NGL"). The change in our segments stems primarily from (i) a multi-year transition in the midstream energy industry driven by increased competition that has reduced the stand alone earnings opportunities of our supply and logistics activities such that those activities now primarily support our effort to increase the utilization of our Crude Oil and NGL assets and (ii) internal changes regarding the oversight and reporting of our assets and related results of operations.

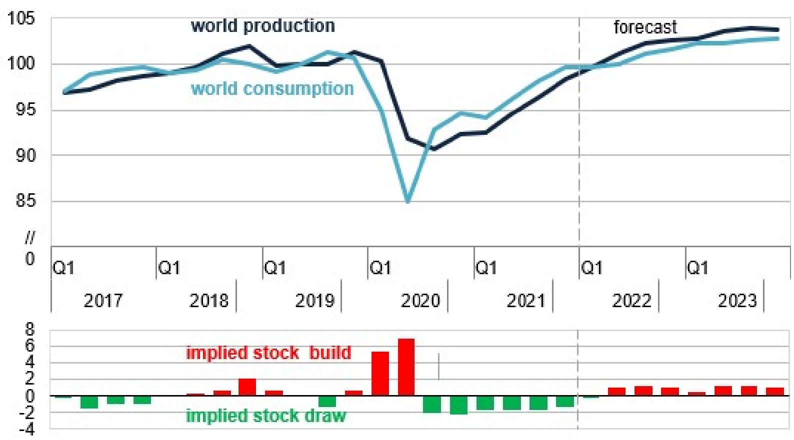
Additionally, during the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Permian JV formation in October 2021, our CODM determined this modification resulted in amounts that were more meaningful to evaluate segment performance. See Note 7 to our Consolidated Financial Statements for additional information regarding the Permian JV.

All segment data and related disclosures for earlier periods presented herein have been recast to reflect the new segment reporting structure and the modification to our definition of Segment Adjusted EBITDA. See Note 20 to our Consolidated Financial Statements for additional information.

Market Overview and Outlook

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 2017 and the U.S. Energy Information Administration's ("EIA") Short-Term Energy Outlook as of February 2022:

World Liquid Fuels Production and Consumption Balance (1)
(in millions of barrels per day)



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(1) Barrels produced and consumed per quarter.

Global crude oil demand at the end of 2021 was near pre-COVID levels, with the EIA and other third parties forecasting demand to exceed 2019 levels by late 2022 and continue to grow for the foreseeable future. We believe this demand growth combined with the multi-year backdrop of reduced upstream investment and a continuation of OPEC discipline could further exacerbate many of the supply concerns that emerged in 2021. This includes tight global markets and continued commodity price volatility. As a result, we expect North American energy supply to play a critical long-term role in meeting global demand and the Permian Basin to drive the vast majority of U.S. production growth in the coming years. It is against this macro backdrop that we expect to generate significant positive free cash flow on a multi-year basis, supported by our existing base and integrated business model.

Building on the actions we took in 2020 to ensure that we were well positioned to manage through the pandemic, in 2021 we continued to build momentum and reinforce our long-term positioning. This included further optimizing our asset portfolio including, but not limited to, exceeding our asset sales target, substantially completing our multi-year capital program, and closing a highly strategic joint venture in the Permian Basin through a cashless and debt-free transaction. Additionally, we reduced debt by $1 billion, meaningfully reduced capital expenditures by $230 million versus our initial 2021 guidance, and further streamlined our U.S. and Canadian operations and organizational cost structure.

While each of these actions should contribute to a stronger balance sheet and enhanced liquidity and long-term financial flexibility, we can provide no assurance that we will be able to effect certain future actions (such as additional capital reductions, asset sales and expense reductions) and additional actions may be necessary to achieve our balance sheet, liquidity and financial security objectives. See "Risk Factors—Risks Related to Our Business" in Item 1A.

While some modifications in our operations continue to be necessary to deal with risks associated with the COVID-19 pandemic, we have not experienced any material constraints on our ability to continue our essential business functions and have not incurred any significant additional operating costs as a result of the pandemic. We remain focused on the health and safety of our workforce, and have modified our operations in ways that we believe are prudent and appropriate in order to protect our employees while continuing to operate our assets in an effective, safe and responsible manner.

Many governments have enacted or are contemplating measures to provide aid and economic stimulus in response to the COVID-19 pandemic. These measures include actions by both the United States federal government and the government of Canada. There has been no material direct impact to our financial position, results of operations or cash flows resulting from these measures. However, our Canadian subsidiary participated in a wage subsidy program during 2021 and 2020 for subsidies totaling approximately $7 million and $23 million, respectively. The impact of such subsidies and incremental COVID-19 costs is included in the line items "Field operating costs" and "General and administrative expenses". See "—Results of Operations" for further discussion.

Overview of Operating Results

We recognized net income attributable to PAA of $593 million for the year ended December 31, 2021 compared to a net loss attributable to PAA of $2.590 billion for the year ended December 31, 2020 and net income attributable to PAA of $2.171 billion for the year ended December 31, 2019. The net loss for the 2020 period was primarily driven by the macroeconomic and industry specific challenges discussed above which resulted in goodwill impairment losses and non-cash impairment charges 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 totaling approximately $3.4 billion. In addition, we recognized approximately $233 million of inventory valuation adjustments due to declines in commodity prices during the first quarter of 2020. The 2021 period includes a net loss on asset sales and asset impairments of $592 million, a majority of which was related to the write-down of our natural gas storage facilities, which were classified as held for sale in the second quarter and sold in the third quarter.

Results from our reporting segments were lower for the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to less favorable crude oil market conditions.

Results from our reporting segments were lower for the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to less favorable crude oil differentials and NGL sales margins and lower volumes, partially offset by the favorable impact of contango market conditions.

See the "—Results of Operations" section below for further discussion.

Results of Operations

Consolidated Results

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

	Year Ended December 31,			Variance			
				2021-2020		2020-2019	
	2021	2020	2019	$	%	$	%
Product sales revenues	$ 40,883	$ 22,058	$ 32,272	$ 18,825	85 %	$ (10,214)	(32)%
Services revenues	1,195	1,232	1,397	(37)	(3)%	(165)	(12)%
Purchases and related costs	(38,504)	(20,431)	(29,452)	(18,073)	(88)%	9,021	31 %
Field operating costs	(1,065)	(1,076)	(1,303)	11	1 %	227	17 %
General and administrative expenses	(292)	(271)	(297)	(21)	(8)%	26	9 %
Depreciation and amortization	(774)	(653)	(601)	(121)	(19)%	(52)	(9)%
Gains/(losses) on asset sales and asset impairments, net	(592)	(719)	(28)	127	18 %	(691)	**
Goodwill impairment losses	—	(2,515)	—	2,515	100 %	(2,515)	N/A
Equity earnings in unconsolidated entities	274	355	388	(81)	(23)%	(33)	(9)%
Gain on/(impairment of) investments in unconsolidated entities, net	2	(182)	271	184	101 %	(453)	(167)%
Interest expense, net	(425)	(436)	(425)	11	3 %	(11)	(3)%
Other income, net	19	39	24	(20)	(51)%	15	63 %
Income tax (expense)/benefit	(73)	19	(66)	(92)	(484)%	85	129 %
Net income/(loss)	648	(2,580)	2,180	3,228	125 %	(4,760)	(218)%
Net income attributable to noncontrolling interests	(55)	(10)	(9)	(45)	(450)%	(1)	(11)%
Net income/(loss) attributable to PAA	$ 593	$ (2,590)	$ 2,171	$ 3,183	123 %	$ (4,761)	(219)%
Basic net income/(loss) per common unit	$ 0.55	$ (3.83)	$ 2.70	$ 4.38	**	$ (6.53)	**
Diluted net income/(loss) per common unit	$ 0.55	$ (3.83)	$ 2.65	$ 4.38	**	$ (6.48)	**
Basic weighted average common units outstanding	716	728	727	(12)	**	1	**
Diluted weighted average common units outstanding	716	728	800	(12)	**	(72)	**

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

Revenues and Purchases

Fluctuations in our consolidated revenues and purchases and related costs are primarily associated with our merchant activities and generally explained in large part by changes in commodity prices. Our crude oil and NGL merchant activities are not directly affected by the absolute level of prices because the commodities that we buy and sell are generally indexed to the same pricing indices. Both product sales revenues and purchases and related costs will fluctuate with market prices; however, the absolute margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. Additionally, product sales revenues include the impact of gains and losses related to derivative instruments used to manage our exposure to commodity price risk associated with such sales and purchases.

A majority of our sales and purchases are indexed to West Texas Intermediate ("WTI"). The following table presents the range of the NYMEX WTI benchmark price of crude oil over the last three years (in dollars per barrel):

	NYMEX WTI Crude Oil Price		
During the Year Ended December 31,	**Low**	**High**	**Average**
2021	$ 48	$ 85	$ 68
2020	$ (38)	$ 63	$ 39
2019	$ 46	$ 66	$ 57

Product sales revenues and purchases increased for the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to higher prices and volumes in the 2021 period.

Product sales revenues and purchases decreased for the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to lower prices and volumes in the 2020 period.

Revenues from services decreased for the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to the sale of assets, partially offset by the recognition of revenues associated with deficiencies under minimum volume commitments in 2020.

Revenues from services decreased for the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to lower pipeline volumes, a portion of which were covered by minimum volume commitments for which the associated revenue was deferred to future periods.

See further discussion of our net revenues in the "—Analysis of Operating Segments" section below.

Field Operating Costs

See discussion of field operating costs in the "—Analysis of Operating Segments" section below.

General and Administrative Expenses

The increase in general and administrative expenses for the year the year ended December 31, 2021 compared to the year ended December 31, 2020 was primarily due to (i) transaction-related costs incurred in connection with the formation of the Permian JV (which impacts our general and administrative expenses but are excluded in the calculation of Adjusted EBITDA and Segment Adjusted EBITDA), (ii) increased information systems costs and (iii) reduced wage subsidies received by our Canadian subsidiary, partially offset by other lower employee-compensation related items during the 2021 period.

The decrease in general and administrative expenses for the year the year ended December 31, 2020 compared to the year ended December 31, 2019 was primarily due to (i) lower equity-based compensation costs on liability-classified awards (which is not excluded in the calculation of Adjusted EBITDA and Segment Adjusted EBITDA), due to a decrease in our common unit price, (ii) decreased travel and entertainment costs, (iii) lower compensation costs including the benefit of wage subsidies received by our Canadian subsidiary and (iv) general cost reductions associated with exiting low margin, high administrative cost businesses. Such items were partially offset by an overall increase in compensation costs related to severance costs associated with our efforts to streamline our organization.

Depreciation and Amortization

Depreciation and amortization expense increased for the year ended December 31, 2021 compared to the year ended December 31, 2020 largely driven by (i) a reduction in the useful lives of certain assets and (ii) additional depreciation expense associated with acquired assets, partially offset by a reduction in depreciation expense associated with assets sold. See Note 6 to our Consolidated Financial Statements for additional information.

Depreciation and amortization expense increased for the year ended December 31, 2020 compared to the year ended December 31, 2019 largely driven by additional depreciation expense associated with acquired assets, the completion of various investment capital projects and a reduction in the useful lives of certain assets, partially offset by a reduction in depreciation expense associated with assets sold.

Gains/Losses on Asset Sales and Asset Impairments, Net

The net losses on asset sales and asset impairments for 2021 primarily included (i) an approximate $220 million non-cash impairment charge recognized in the third quarter related to the write-down of certain crude oil storage terminal assets as a result of decreased demand for our services due to changing market conditions, (ii) an approximate $475 million non-cash impairment charge related to the write-down of our Pine Prairie and Southern Pines natural gas storage facilities upon classification as held for sale during the second quarter (these assets were sold in August 2021), and (iii) a gain of $106 million recognized in the second quarter related to the asset exchange agreement (the "Asset Exchange") involving the sale of our Milk River crude oil pipeline in exchange for additional interests in certain of the Empress gas processing plants.

The net loss on asset sales and asset impairments for the year ended December 31, 2020 included (i) non-cash impairment losses on held and used assets of approximately $541 million related to the write-down of (a) certain pipeline and other long-lived assets due to the current macroeconomic and geopolitical conditions including the collapse of oil prices driven by both the decrease in demand caused by the COVID-19 pandemic and excess supply, as well as changing market conditions and expected lower crude oil production in certain regions, and (b) idled or underutilized assets for which is it has been determined that it is unlikely that opportunities will exist in the future to recover our investment in these assets and (ii) net losses of approximately $178 million related to the sale of assets, including non-cash impairments recognized upon classification as assets held for sale.

The net loss on asset sales and asset impairments for the year ended December 31, 2019 was largely driven by a loss on the sale of a storage terminal in North Dakota.

See Note 6 and Note 7 to our Consolidated Financial Statements for additional information regarding these asset sales and asset impairments.

Goodwill Impairment Losses

During the first quarter of 2020, we recognized a goodwill impairment charge of $2.5 billion, representing the entire balance of goodwill. See Note 8 to our Consolidated Financial Statements for additional information.

Gain on/(Impairment of) Investments in Unconsolidated Entities, Net

During the year ended December 31, 2020, we recognized losses of $202 million related to the write-down of certain of our investments in unconsolidated entities. Additionally, we recognized a gain of $21 million related to our sale of a 10% interest in Saddlehorn Pipeline Company, LLC.

During the year ended December 31, 2019, we recognized a non-cash gain of $269 million related to a fair value adjustment resulting from the accounting for the contribution of our undivided joint interest in the Capline pipeline system for an equity interest in Capline Pipeline Company LLC. See Note 9 to our Consolidated Financial Statements for additional information regarding our unconsolidated entities.

Interest Expense

Interest expense is primarily impacted by:

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

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

		Average LIBOR	Weighted Average Interest Rate [(1)]
Interest expense for the year ended December 31, 2019	$ 425	2.2 %	4.4 %
Impact of lower capitalized interest	10		
Impact of borrowings under credit facilities and commercial paper program	3		
Impact of issuance and retirement of senior notes	(4)		
Other	2		
Interest expense for the year ended December 31, 2020	$ 436	0.5 %	4.1 %
Impact of issuance and retirement of senior notes	(13)		
Impact of borrowings under credit facilities and commercial paper program	(4)		
Impact of lower capitalized interest	6		
Interest expense for the year ended December 31, 2021	$ 425	0.1 %	4.2 %

(1) Excludes commitment and other fees.

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

Other Income, Net

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

	Year Ended December 31,		
	2021	2020	2019
Gain related to mark-to-market adjustment of our Preferred Distribution Rate Reset Option [(1)]	$ 14	$ 20	$ 2
Net gain on foreign currency revaluation [(2)]	3	13	15
Other	2	6	7
	$ 19	$ 39	$ 24

(1) See Note 13 to our Consolidated Financial Statements for additional information.

(2) The activity during the years presented was primarily related to the impact from the change in the USD to CAD exchange rate on the portion of our intercompany net investment that is not long-term in nature.

Income Tax (Expense)/Benefit

The net unfavorable income tax variance for the year ended December 31, 2021 compared to the year ended December 31, 2020 was primarily a result of increased income in our Canadian operations.

The net favorable income tax variance for the year ended December 31, 2020 compared to the year ended December 31, 2019 was primarily due to lower taxable earnings from our Canadian operations and lower year-over-year income as impacted by fluctuations in the derivative mark-to-market valuations in our Canadian operations, partially offset by the recognition of a deferred tax benefit of approximately $60 million during the second quarter of 2019 as a result of the reduction of the provincial tax rate in Alberta, Canada.

Noncontrolling Interests

The increase in amounts attributable to noncontrolling interests for the year ended December 31, 2021 compared to the year ended December 31, 2020 was due to the formation of the Permian JV in October 2021. See Note 7 to our Consolidated Financial Statements for additional information.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as "non-GAAP financial measures” in its evaluation of past performance and prospects for the future and to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes.

The primary additional measures used by management are earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, of unconsolidated entities), gains and losses on asset sales and asset impairments, goodwill impairment losses and gains on and impairments of investments in unconsolidated entities, adjusted for certain selected items impacting comparability ("Adjusted EBITDA”), Adjusted EBITDA attributable to PAA, Implied distributable cash flow ("DCF”), Free Cash Flow and Free Cash Flow after Distributions.

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Adjusted EBITDA attributable to PAA and Implied DCF are reconciled to Net Income/(Loss), and Free Cash Flow and Free Cash Flow after Distributions are reconciled to Net Cash Provided by Operating Activities, the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Consolidated Financial Statements and accompanying notes. See "—Liquidity and Capital Resources—Liquidity Measures” for additional information regarding Free Cash Flow and Free Cash Flow after Distributions.

Performance Measures

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

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

The following table sets forth the reconciliation of the non-GAAP financial performance measures Adjusted EBITDA, Adjusted EBITDA attributable to PAA and Implied DCF from Net Income/(Loss) (in millions):

	Year Ended December 31,			Variance			
				2021-2020		2020-2019	
	2021	2020	2019	$	%	$	%
Net income/(loss)	$ 648	$ (2,580)	$ 2,180	$ 3,228	125 %	$ (4,760)	(218)%
Interest expense, net	425	436	425	(11)	(3)%	11	3 %
Income tax expense/(benefit)	73	(19)	66	92	484 %	(85)	(129)%
Depreciation and amortization	774	653	601	121	19 %	52	9 %
(Gains)/losses on asset sales and asset impairments, net	592	719	28	(127)	(18)%	691	**
Goodwill impairment losses	—	2,515	—	(2,515)	(100)%	2,515	N/A
(Gain on)/impairment of investments in unconsolidated entities, net	(2)	182	(271)	(184)	(101)%	453	167 %
Depreciation and amortization of unconsolidated entities (1)	123	73	62	50	68 %	11	18 %
Selected Items Impacting Comparability:							
(Gains)/losses from derivative activities and inventory valuation adjustments	(271)	480	160	(751)	**	320	**
Long-term inventory costing adjustments	(94)	44	(20)	(138)	**	64	**
Deficiencies under minimum volume commitments, net	(7)	74	(18)	(81)	**	92	**
Equity-indexed compensation expense	19	19	17	—	**	2	**
Net (gain)/loss on foreign currency revaluation	(4)	(3)	14	(1)	**	(17)	**
Line 901 incident	15	—	10	15	**	(10)	**
Significant transaction-related expenses	16	3	—	13	**	3	**
Selected Items Impacting Comparability - Segment Adjusted EBITDA (2)	(326)	617	163	(943)	**	454	**
Gains from derivative activities (3)	(14)	(20)	(2)	6	**	(18)	**
Net gain on foreign currency revaluation (4)	(3)	(13)	(15)	10	**	2	**
Net gain on early repayment of senior notes (5)	—	(3)	—	3	**	(3)	**
Selected Items Impacting Comparability - Adjusted EBITDA (6)	(343)	581	146	(924)	**	435	**
Adjusted EBITDA (6)	$ 2,290	$ 2,560	$ 3,237	$ (270)	(11)%	$ (677)	(21)%
Adjusted EBITDA attributable to noncontrolling interests (7)	(94)	(14)	(10)	(80)	**	(4)	(40)%
Adjusted EBITDA attributable to PAA	$ 2,196	$ 2,546	$ 3,227	$ (350)	(14)%	$ (681)	(21)%
Adjusted EBITDA (6)	$ 2,290	$ 2,560	$ 3,237	$ (270)	(11)%	$ (677)	(21)%
Interest expense, net of certain non-cash items (8)	(401)	(415)	(407)	14	3 %	(8)	(2)%
Maintenance capital (9)	(168)	(216)	(287)	48	22 %	71	25 %
Investment capital of noncontrolling interests (10)	(9)	—	—	(9)	N/A	—	N/A
Current income tax expense	(50)	(51)	(112)	1	2 %	61	54 %
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings (11)	16	13	(49)	3	**	62	**
Distributions to noncontrolling interests (12)	(14)	(10)	(6)	(4)	(40)%	(4)	(67)%
Implied DCF	$ 1,664	$ 1,881	$ 2,376	$ (217)	(12)%	$ (495)	(21)%
Preferred unit cash distributions (12)	(198)	(198)	(198)				
Implied DCF Available to Common Unitholders	$ 1,466	$ 1,683	$ 2,178				
Common unit cash distributions (12)	(517)	(655)	(1,004)				
Implied DCF Excess (13)	$ 949	$ 1,028	$ 1,174				

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

(1) We exclude our proportionate share of the depreciation and amortization expense (including write-downs related to cancelled projects) of unconsolidated entities when reviewing Adjusted EBITDA, similar to our consolidated assets.

(2) For a more detailed discussion of these selected items impacting comparability, see the footnotes to the Segment Adjusted EBITDA Reconciliation table in Note 20 to our Consolidated Financial Statements.

(3) The Preferred Distribution Rate Reset Option of our Series A preferred units is accounted for as an embedded derivative and recorded at fair value in our Consolidated Financial Statements. The associated gains and losses are not integral to our results and were thus classified as a selected item impacting comparability. See Note 13 to our Consolidated Financial Statements for additional information regarding the Preferred Distribution Rate Reset Option.

(4) During the periods presented, there were fluctuations in the value of CAD to USD, resulting in the realization of foreign exchange gains and losses on the settlement of foreign currency transactions as well as the revaluation of monetary assets and liabilities denominated in a foreign currency. The associated gains and losses are not integral to our results and thus were classified as a selected item impacting comparability.

(5) Includes net gains recognized in connection with the repurchase of our outstanding senior notes on the open market. See Note 11 to our Consolidated Financial Statements for additional information.

(6) Other income/(expense), net per our Consolidated Statements of Operations, adjusted for selected items impacting comparability ("Adjusted other income/(expense), net") is included in Adjusted EBITDA and excluded from Segment Adjusted EBITDA.

(7) Reflects amounts attributable to noncontrolling interests in the Permian JV and Red River Pipeline LLC.

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

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

(10) Investment capital expenditures attributable to noncontrolling interests that reduce Implied DCF available to PAA common unitholders.

(11) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, and selected items impacting comparability of unconsolidated entities).

(12) Cash distributions paid during the period presented.

(13) Excess DCF is retained to establish reserves for debt repayment, future distributions, equity repurchases, capital expenditures and other partnership purposes.

Analysis of Operating Segments

We manage our operations through two operating segments: Crude Oil and NGL. Our CODM (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Adjusted EBITDA, segment volumes and maintenance capital investment.

We define Segment Adjusted EBITDA as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses, plus (d) our proportionate share of the depreciation and amortization expense (including write-downs related to cancelled projects) of unconsolidated entities, further adjusted for (e) certain selected items including (i) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (ii) long-term inventory costing adjustments, (iii) charges for obligations that are expected to be settled with the issuance of equity instruments, (iv) amounts related to deficiencies associated with minimum volume commitments, net of applicable amounts subsequently recognized into revenue and (v) other items that our CODM believes are integral to understanding our core segment operating performance and (f) to exclude the portion of all preceding items that is attributable to noncontrolling interests ("Adjusted EBITDA attributable to noncontrolling interests"). See Note 20 to our Consolidated Financial Statements for a reconciliation of Segment Adjusted EBITDA to Net income/(loss) attributable to PAA.

In connection with our merchant activities, our Crude Oil and NGL segments may enter into intersegment transactions for the purchase or sale of products, along with services such as the transportation, terminalling or storage of products. Intersegment transactions are conducted at rates similar to those charged to third parties or rates that we believe approximate market. Intersegment activities are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expenses and general and administrative overhead expenses between segments based on management's assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

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

Crude Oil Segment

Our Crude Oil segment operations generally consist of gathering and transporting crude oil using pipelines, gathering systems, trucks and at times on barges or railcars, in addition to providing terminalling, storage and other facilities-related services utilizing our integrated assets across the United States and Canada. Our assets serve third parties and are also supported by our merchant activities. Our merchant activities include the purchase of crude oil supply and the movement of this supply on our assets to sales locations, including our terminals, third-party connecting carriers, regional hubs or to refineries. Our merchant activities are subject to our risk management policies and may include the use of derivative instruments to hedge our exposure.

Our Crude Oil segment generates revenue through a combination of tariffs, pipeline capacity agreements and other transportation fees, month-to-month and multi-year storage and terminalling agreements and the sale of gathered and bulk-purchased crude oil. Tariffs and other fees on our pipeline systems are typically based on volumes transported and vary by receipt point and delivery point. Fees for our terminalling and storage services are based on capacity leases and throughput volumes. Generally, results from our merchant activities are impacted by (i) increases or decreases in our lease gathering crude oil purchases volumes and (ii) the overall strength, weakness and volatility of market conditions, including regional differentials and time spreads. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. The segment results also include the direct fixed and variable field costs of operating the crude oil assets, as well as an allocation of indirect operating costs.

The following tables set forth our operating results from our Crude Oil segment:

Operating Results [1] (in millions, except per barrel data)	Year Ended December 31, 2021	2020	2019	Variance 2021-2020 $	%	Variance 2020-2019 $	%
Revenues	$ 40,470	$ 22,199	$ 31,655	$ 18,271	82 %	$ (9,456)	(30)%
Purchases and related costs	(37,540)	(19,712)	(28,227)	(17,828)	(90)%	8,515	30 %
Field operating costs	(824)	(876)	(1,064)	52	6 %	188	18 %
Segment general and administrative expenses [2]	(221)	(205)	(216)	(16)	(8)%	11	5 %
Equity earnings in unconsolidated entities	274	355	388	(81)	(23)%	(33)	(9)%
Adjustments [3]:							
Depreciation and amortization of unconsolidated entities	123	73	62	50	68 %	11	18 %
(Gains)/losses from derivative activities and inventory valuation adjustments	(252)	259	180	(511)	**	79	**
Long-term inventory costing adjustments	(67)	43	(35)	(110)	**	78	**
Deficiencies under minimum volume commitments, net	(7)	74	(18)	(81)	**	92	**
Equity-indexed compensation expense	19	19	17	—	**	2	**
Net (gain)/loss on foreign currency revaluation	(3)	(2)	11	(1)	**	(13)	**
Line 901 incident	15	—	10	15	**	(10)	**
Significant transaction-related expenses	16	3	—	13	**	3	**
Adjusted EBITDA attributable to noncontrolling interests	(94)	(14)	(10)	(80)	**	(4)	**
Segment Adjusted EBITDA	$ 1,909	$ 2,216	$ 2,753	$ (307)	(14)%	$ (537)	(20)%
Maintenance capital	$ 100	$ 171	$ 248	$ (71)	(42)%	$ (77)	(31)%

Average Volumes	Year Ended December 31, 2021	2020	2019	Variance 2021-2020 Volumes	%	Variance 2020-2019 Volumes	%
Tariff activities volumes [4]							
Crude oil pipelines tariff volumes (by region):							
Permian Basin [5]	4,412	4,427	4,690	(15)	— %	(263)	(6)%
South Texas / Eagle Ford [5]	326	380	446	(54)	(14)%	(66)	(15)%
Mid-Continent [5]	455	379	498	76	20 %	(119)	(24)%
Gulf Coast	158	134	165	24	18 %	(31)	(19)%
Rocky Mountain [5]	332	245	293	87	36 %	(48)	(16)%
Western	236	223	198	13	6 %	25	13 %
Canada	286	294	323	(8)	(3)%	(29)	(9)%
Crude oil pipelines tariff activities total volumes	6,205	6,082	6,613	123	2 %	(531)	(8)%
Commercial crude oil storage capacity [5][6]	73	79	76	(6)	(8)%	3	4 %
Crude oil lease gathering purchases [4][7]	1,330	1,174	1,162	156	13 %	12	1 %

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

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

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

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

(4) Average daily volumes in thousands of barrels per day calculated as the total volumes (attributable to our interest for pipelines owned by unconsolidated entities or undivided joint interests) for the year divided by the number of days in the year. Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

(5) Includes volumes (attributable to our interest) from assets owned by unconsolidated entities.

(6) Average monthly capacity in millions of barrels per day calculated as total volumes for the year divided by the number of months in the year.

(7) Of this amount, approximately 1,038 thousand barrels per day ("MBbls/d"), 862 MBbls/d and 767 MBbls/d were purchased in the Permian Basin for the years ended December 31, 2021, 2020 and 2019, respectively.

Segment Adjusted EBITDA

Crude Oil Segment Adjusted EBITDA decreased for the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to less favorable crude oil market conditions for our merchant activities in 2021 (largely associated with decreased contango margins and continuing compressed regional basis differentials). In addition, the 2021 period was negatively impacted by asset sales. These impacts were partially offset by lower field operating costs and slightly higher volumes on our pipeline assets.

Crude Oil Segment Adjusted EBITDA decreased for the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to overall less favorable crude oil market conditions for our merchant activities during 2020 (compressed regional basis differentials, partially offset by the favorable impact of contango margins) and lower pipeline volumes caused by the impact of the COVID-19 pandemic, partially offset by lower field operating costs.

The various components of Segment Adjusted EBITDA are discussed further below.

Revenues, Net of Purchases and Related Costs ("net revenues") and Equity Earnings in Unconsolidated Entities. The following is a discussion of the significant items impacting net revenues and equity earnings in unconsolidated entities for the comparable 2021, 2020 and 2019 periods.

- *COVID-19 Impact.* Crude oil production in the U.S. stabilized in 2021 and while it began increasing in the second half of the year, on average, U.S. crude oil production was slightly lower than the 2020 average. In 2020, crude oil production in the U.S. was nearly 1 million barrels per day lower than the 2019 average, as the pandemic significantly reduced demand for crude oil.

  These factors resulted in lower pipeline transportation net revenues across the majority of the regions in which we operate in 2020 as compared to 2019 and unfavorable market conditions and lower earnings from our merchant activities during 2020 and 2021 highlighted by less favorable crude oil differentials, particularly the differential between the value of crude oil in the Permian Basin compared to the Gulf Coast market. Those negative conditions were partially offset by the favorable impact of contango market conditions during 2020 and, to a lesser extent, during 2021.

- *Winter Storm Uri.* The extreme winter weather event that occurred in February 2021 ("Winter Storm Uri") resulted in shut-ins that further compounded the impact of the COVID-19 pandemic-related reset to production on our pipeline volumes. The resulting unfavorable impact on our revenues was more than offset by the favorable impact from lower power costs on equity earnings and field operating costs, as discussed further below.

- *Equity Earnings in Unconsolidated Entities.* Volumes on pipelines owned by unconsolidated entities were also negatively impacted by the COVID-19 pandemic-related production declines and, for the pipelines located in the Permian Basin and South Texas/Eagle Ford regions, the effects of Winter Storm Uri in 2021. The unfavorable impact of the lower volumes on equity earnings was partially offset by lower power costs, including the impact of gains related to hedged power costs resulting from Winter Storm Uri.

  In addition, equity earnings for the 2021 period were negatively impacted by (i) the write-off of costs associated with the cancellation of capital projects and (ii) depreciation expense and transition costs associated with phase one of the Wink to Webster pipeline being placed into service during the first quarter of 2021. Such costs are included in the line item "Depreciation and amortization of unconsolidated entities" in the table above as an adjustment to arrive at Segment Adjusted EBITDA.

- *Minimum Volume Commitments.* A portion of the lower volumes experienced on our pipelines, and pipelines owned by unconsolidated entities, in 2020 were covered by minimum volume commitments, some of which had make-up rights. For contracts that have make-up rights, although payment has been received associated with the volume deficiency, the earnings are not recognized until future periods when either the shortfall is made up or when the shipper's make-up rights expire or it is determined that their ability to utilize the make-up right is remote. Such deficiencies are reflected as an "Adjustment" in the table above as discussed further below under "*—Adjustments—Deficiencies under minimum volume commitments, net.*"

- *Asset Sales*. Storage and terminalling fees for 2021 compared to 2020 were unfavorably impacted by the sale of (i) our natural gas storage facilities in August 2021 and (ii) our Los Angeles Basin terminals in October 2020.

Field Operating Costs. The decrease in field operating costs for the year ended December 31, 2021 compared to the year ended December 31, 2020 was primarily due to (i) lower power costs, including the impact of gains related to hedged power costs resulting from Winter Storm Uri, (ii) lower compensation costs resulting from lower headcount and the sales of our natural gas storage facilities in August 2021 and Los Angeles Basin terminals in October 2020, (iii) lower long-haul third-party trucking costs and a decrease in company personnel and truck costs as more of our supply was connected to pipelines and taken off trucks and (iv) streamlining efforts which have resulted in decreases in variable costs. These favorable impacts were partially offset by (i) incremental operating costs from the Permian JV and (ii) additional estimated costs associated with the Line 901 incident (which impact field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above).

The decrease in field operating costs for the year ended December 31, 2020 compared to the year ended December 31, 2019 was primarily due to (i) a decrease in variable costs due to lower volumes, (ii) a decrease of maintenance and integrity management activities, primarily due to interval changes facilitated through risk-based data application, (iii) reduced activity at our rail terminals, (iv) a decrease in long-haul third-party trucking costs and a decrease in company personnel and truck costs as more of our supply was connected to pipelines and taken off trucks and (v) additional estimated costs recognized in 2019 associated with the Line 901 incident (which impact field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above). Such favorable impacts were partially offset by higher property taxes attributable to assets placed in service in 2020 and increased property valuations.

Segment General and Administrative Expenses. See the "—Consolidated Results" section above for a discussion of general and administrative expenses.

Adjustments. The following is a discussion of adjustments included in the calculation of Segment Adjusted EBITDA, the performance measure utilized by our CODM in the evaluation of segment results.

- *Deficiencies under minimum volume commitments, net.* Many industry infrastructure projects developed and completed over the last several years were underpinned by long-term minimum volume commitment contracts whereby the shipper agreed to either: (i) ship and pay for certain stated volumes or (ii) pay the agreed upon price for a minimum contract quantity. Some of these agreements include make-up rights if the minimum volume is not met. If a counterparty has a make-up right associated with a deficiency, we bill the counterparty and defer the revenue attributable to the counterparty's make-up right but record an adjustment to reflect such amount associated with the current period activity in Segment Adjusted EBITDA. We subsequently recognize the revenue, and record a corresponding reversal of the adjustment, at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty's ability to utilize the make-up right is remote. The amount presented as an "Adjustment" in the table above reflects the net adjustment for revenues deferred during the period and the reversal of previously deferred revenues that were recognized during the period.

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

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

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

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement and/or refurbishment of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The decrease in maintenance capital for the year ended December 31, 2021 compared to the year ended December 31, 2020 as well as the comparable period for 2020 and 2019 was due to timing changes, the completion of multi-year reliability improvement programs, application of updated regulatory guidance and lower tractor trailer lease buyouts, among other factors. The decrease for the year ended December 31, 2021 compared to the year ended December 31, 2020 was also due to the sales of our natural gas storage facilities and Los Angeles Basin terminals.

NGL Segment

Our NGL segment operations involve natural gas processing and NGL fractionation, storage, transportation and terminalling. Our NGL revenues are primarily derived from a combination of (i) providing gathering, fractionation, storage, and/or terminalling services to third-party customers for a fee, and (ii) extracting NGL mix supply from the gas stream processed at our Empress straddle plant facility as well as acquiring NGL mix supply, which mix supply is then transported, stored and fractionated into finished products and sold to customers.

Generally, our segment results are impacted by (i) increases or decreases in our NGL sales volumes, (ii) the overall strength, weakness and volatility of market conditions, including the differential between the price of natural gas and the extracted NGL, as well as location differentials and time spreads, and (iii) the effects of competition on our NGL margins. In addition, we utilize various risk management strategies to manage our commodity exposure.

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

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

Operating Results [1] (in millions, except per barrel data)	Year Ended December 31, 2021	2020	2019	Variance 2021-2020 $	%	Variance 2020-2019 $	%
Revenues	$ 1,968	$ 1,360	$ 2,439	$ 608	45 %	$ (1,079)	(44)%
Purchases and related costs	(1,324)	(988)	(1,650)	(336)	(34)%	662	40 %
Field operating costs	(241)	(200)	(239)	(41)	(21)%	39	16 %
Segment general and administrative expenses [2]	(71)	(66)	(81)	(5)	(8)%	15	19 %
Adjustments [3]:							
(Gains)/losses from derivative activities and inventory valuation adjustments	(19)	221	(20)	(240)	**	241	**
Long-term inventory costing adjustments	(27)	1	15	(28)	**	(14)	**
Net (gain)/loss on foreign currency revaluation	(1)	(1)	3	—	**	(4)	**
Segment Adjusted EBITDA	$ 285	$ 327	$ 467	$ (42)	(13)%	$ (140)	(30)%
Maintenance capital	$ 68	$ 45	$ 39	$ 23	51 %	$ 6	15 %

Average Volumes (in thousands of barrels per day) [4]	Year Ended December 31, 2021	2020	2019	Variance 2021-2020 Volumes	%	Variance 2020-2019 Volumes	%
NGL fractionation	129	129	144	—	— %	(15)	(10)%
NGL pipeline tariff	179	184	192	(5)	(3)%	(8)	(4)%
NGL sales	141	144	207	(3)	(2)%	(63)	(30)%

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

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

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

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

(4) Average daily volumes calculated as the total volumes (attributable to our interest for pipelines and facilities in which we have undivided joint interests) for the year divided by the number of days in the year.

Segment Adjusted EBITDA

NGL Segment Adjusted EBITDA decreased for the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily due to (i) higher power costs and (ii) lower wage subsidies received by our Canadian subsidiary in the 2021 period, partially offset by (iii) the favorable impact of higher realized fractionation spreads between the price of natural gas and the extracted NGL ("frac spreads").

NGL Segment Adjusted EBITDA decreased for the year ended December 31, 2020 compared to the year ended December 31, 2019 primarily due to less favorable NGL sales margins as a result of (i) warmer weather during the fourth quarter of 2020, (ii) weaker frac spreads and (iii) lower NGL supply. Such unfavorable impacts were partially offset by the favorable impact of wage subsidies received by our Canadian subsidiary in the 2020 period.

The various components of Segment Adjusted EBITDA are discussed further below:

Net Revenues. The following is a discussion of the significant items impacting net revenues for the comparable 2021, 2020 and 2019 periods.

- Net revenues from our NGL activities, excluding the impact of derivative activities and inventory valuation and long-term inventory costing adjustments, increased slightly for the year ended December 31, 2021 compared to the year ended December 31, 2020 due to higher realized frac spreads, partially offset by the absence of the favorable impact of a deficiency payment in 2020 upon the expiration of a multi-year contract.

- Net revenues from our NGL activities decreased for the year ended December 31, 2020 compared to the year ended December 31, 2019, primarily due to (i) warmer weather during the fourth quarter of 2020, (ii) weaker frac spreads, (iii) less NGL supply as a result of lower border flows through our Empress straddle plants, (iv) the impact of the sale of certain NGL storage terminals in the fourth quarter of 2019 and the second quarter of 2020 and (v) the absence of the favorable impact from certain non-recurring items recorded in the second quarter of 2019, partially offset by (vi) the favorable impact of the receipt of a deficiency payment in 2020 upon the expiration of a multi-year contract.

Field Operating Costs. The increase in field operating costs for the year ended December 31, 2021 compared to December 31, 2020 was primarily due to (i) increased power costs related to increased ownership in our Empress straddle plants as well as higher power prices, (ii) higher compensation costs including lower wage subsidies received by our Canadian subsidiary, and (iii) costs associated with an operational incident at our Fort Saskatchewan facility that occurred in late September 2021.

The decrease in field operating costs for the year ended December 31, 2020 compared to December 31, 2019 was primarily due to (i) lower power costs as a result of favorable natural gas and electricity price movements, (ii) reductions in compensation costs, primarily due to the benefit of wage subsidies received by our Canadian subsidiary, (iii) the divestiture of certain NGL storage terminals, and (iv) lower integrity management and maintenance activities due to interval changes facilitated through risk-based data application. Such favorable impacts were partially offset by lower mark-to-market gains in the 2020 period on fuel hedges (which impacts field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above).

Segment General and Administrative Expenses. See the "—Consolidated Results" section above for a discussion of general and administrative expenses.

Adjustments. The following is a discussion of adjustments included in the calculation of Segment Adjusted EBITDA, the performance measure utilized by our CODM in the evaluation of segment results.

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

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

Maintenance Capital. The increase in maintenance capital spending for the year ended December 31, 2021 compared to the year ended December 31, 2020 was primarily due to (i) repair costs at the Fort Saskatchewan facility, (ii) additional projects related to increased ownership in our Empress straddle plants and (iii) various maintenance capital projects at our Sarnia facility, identified through out of service inspections.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities and (ii) borrowings under our credit facilities or commercial paper program. In addition, we may supplement these primary sources of liquidity with proceeds from asset sales, and in the past have utilized funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to, (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products, other expenses and interest payments on outstanding debt, (ii) investment and maintenance capital activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders. In addition, we may use cash for repurchases of common equity. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from investment capital activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities and the sale of assets.

As of December 31, 2021, although we had a working capital deficit of $95 million, we had over $3 billion of liquidity available to meet our ongoing operating, investing and financing needs, subject to continued covenant compliance, as noted below (in millions):

		As of December 31, 2021
Availability under senior unsecured revolving credit facility [1][2]	$	1,296
Availability under senior secured hedged inventory facility [1][2]		1,306
Amounts outstanding under commercial paper program		—
Subtotal		2,602
Cash and cash equivalents		449
Total	$	3,051

(1) Represents availability prior to giving effect to borrowings outstanding under our commercial paper program, which reduce available capacity under the facilities.

(2) Available capacity under our senior unsecured revolving credit facility and senior secured hedged inventory facility was reduced by outstanding letters of credit of $54 million and $44 million, respectively.

Usage of our credit facilities, which provide the financial backstop for our commercial paper program, is subject to ongoing compliance with covenants, as discussed further below. Our borrowing capacity and borrowing costs are also impacted by our credit rating. See Item 1A. "Risk Factors—Risks Related to Our Business—Loss of our investment grade credit rating or the ability to receive open credit could negatively affect our borrowing costs, ability to purchase crude oil, NGL and natural gas supplies or to capitalize on market opportunities."

We believe that we have, and will continue to have, the ability to access our commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquid assets, cash flow from operating activities and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow, including extended disruptions in the financial markets and/or energy price volatility resulting from current macroeconomic and geopolitical conditions associated with the COVID-19 pandemic and/or actions by OPEC. A prolonged material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity and cost of borrowing. See Item 1A. "Risk Factors" for further discussion regarding risks that may impact our liquidity and capital resources.

Credit Agreements, Commercial Paper Program and Indentures

We have three primary credit arrangements, which we use to meet our short-term cash needs. These include our $1.35 billion senior unsecured revolving credit facility maturing in 2026, $1.35 billion senior secured hedged inventory facility maturing in 2024 and $2.7 billion unsecured commercial paper program that is backstopped by our revolving credit facility and our hedged inventory facility. The credit agreements for our revolving credit facilities (which impact our ability to access our commercial paper program because they provide the financial backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements or indentures would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We were in compliance with the covenants contained in our credit agreements and indentures as of December 31, 2021.

Liquidity Measures

Management uses the non-GAAP financial measures Free Cash Flow and Free Cash Flow after Distributions to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes. Free Cash Flow is defined as Net cash provided by operating activities, less Net cash provided by/(used in) investing activities, which primarily includes acquisition, investment and maintenance capital expenditures, investments in unconsolidated entities and the impact from the purchase and sale of linefill, net of proceeds from the sales of assets and further impacted by distributions to, contributions from and proceeds from the sale of noncontrolling interests. Free Cash Flow is further reduced by cash distributions paid to our preferred and common unitholders to arrive at Free Cash Flow after Distributions.

The following table sets forth the reconciliation of the non-GAAP financial liquidity measures Free Cash Flow and Free Cash Flow after Distributions from Net Cash Provided by Operating Activities (in millions):

	Year Ended December 31,		
	2021	2020	2019
Net cash provided by operating activities	$ 1,996	$ 1,514	$ 2,504
Adjustments to reconcile net cash provided by operating activities to free cash flow:			
Net cash provided by/(used in) investing activities	386	(1,093)	(1,765)
Cash contributions from noncontrolling interests	1	12	—
Cash distributions paid to noncontrolling interests (1)	(14)	(10)	(6)
Sale of noncontrolling interest in a subsidiary	—	—	128
Free Cash Flow	$ 2,369	$ 423	$ 861
Cash distributions (2)	(715)	(853)	(1,202)
Free Cash Flow after Distributions	$ 1,654	$ (430)	$ (341)

(1) Cash distributions paid during the period presented.

(2) Cash distributions paid to our preferred and common unitholders during the period presented.

Cash Flow from Operating Activities

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

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

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

Net cash provided by operating activities for the years ended December 31, 2021, 2020 and 2019 was approximately $2.0 billion, $1.5 billion and $2.5 billion, respectively, and primarily resulted from earnings from our operations. Additionally, as discussed further below, changes during these periods in our inventory levels and associated margin balances required as part of our hedging activities impacted our cash flow from operating activities.

During 2021, we decreased the volume of both our crude oil inventory due to fewer storage opportunities in the contango market and our NGL inventory as well as the margin balances required as part of our hedging activities, all of which reduced required funding by short-term debt. The cash inflows associated with these activities were partially offset by higher prices for inventory purchased and stored at the end of the current period compared to the end of 2020.

During 2020, we increased the volume of both our crude oil inventory to be stored during the contango market and our NGL inventory in anticipation of the 2020-2021 heating season as well as the margin balances required as part of our hedging activities, all of which was funded by short-term debt. The cash outflows associated with these activities were partially offset by lower prices for inventory purchased and stored at the end of the current period compared to the end of 2019. Cash provided by operating activities was favorably impacted by cash received for transactions for which the revenue has been deferred pending the completion of future performance obligations. See Note 3 to our Consolidated Financial Statements for additional information.

During 2019, our cash provided by operating activities was positively impacted by the proceeds from the sale of NGL and crude oil inventory that we held and also by the lower weighted average price of NGL inventory compared to prior year amounts.

Investing Activities

Capital Expenditures

In addition to our operating needs, we also use cash for our investment capital projects, maintenance capital activities and acquisition activities. We fund these expenditures with cash generated by operating activities, financing activities and/or proceeds from asset sales. In the near term, we do not plan to issue common equity to fund such expenditures. The following table summarizes our investment, maintenance and acquisition capital expenditures (in millions):

	Year Ended December 31,		
	2021	2020	2019
Investment capital [1][2]	$ 237	$ 921	$ 1,340
Maintenance capital [1]	168	216	287
Acquisition capital [3]	32	310	50
	$ 437	$ 1,447	$ 1,677

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

(2) Includes contributions to unconsolidated entities, accounted for under the equity method of accounting, related to investment capital projects by such entities.

(3) Acquisition capital for 2021 represents the cash consideration paid as part of the Asset Exchange transaction. See Note 7 to our Consolidated Financial Statements for additional information. Acquisition capital for 2020 primarily includes consideration paid in connection with the acquisition of Felix Midstream LLC, a crude oil gathering system located in the Delaware Basin.

Investment Capital Projects

Our investment capital programs consist of investments in midstream infrastructure projects that build upon our core assets and operations. The majority of this investment capital consists of highly-contracted projects that complement our broader system capabilities and support the long-term needs of the upstream and downstream sectors of the industry value chain. The following table summarizes our investment in capital projects (in millions):

Projects	Year Ended December 31, 2021	2020	2019
Permian Basin Takeaway Pipeline Projects (1)	$ 75	$ 292	$ 440
Complementary Permian Basin Projects (2)	73	200	503
Long-Haul Pipeline Projects (Non-Permian)	12	195	98
Selected Facilities/Downstream Projects (3)	41	115	93
Other Projects	36	119	206
Total	$ 237	$ 921	$ 1,340

(1) Represents pipeline projects with takeaway capacity out of the Permian Basin, including (i) our 16% interest in Wink to Webster Pipeline and (ii) our 65% interest in the Cactus II Pipeline.

(2) Includes projects associated with assets included in the Permian JV.

(3) Includes projects at our St. James, Cushing and Fort Saskatchewan terminals.

Projected 2022 Capital Expenditures. Total investment capital for the year ending December 31, 2022 is projected to be approximately $330 million ($275 million net to our interest). Approximately half of our projected investment capital expenditures are expected to be invested in the Permian JV assets. Additionally, maintenance capital for 2022 is projected to be $220 million ($210 million net to our interest). We expect to fund our 2022 investment and maintenance capital expenditures primarily with retained cash flow.

Divestitures

Proceeds from the sale of assets have generally been used to fund our investment capital projects and reduce debt levels. The following table summarizes the proceeds received from divestitures during the last three years (in millions):

	Year Ended December 31, 2021	2020	2019
Proceeds from divestitures (1) (2)	$ 875	$ 451	$ 205

(1) Represents proceeds, including working capital adjustments, net of transaction costs.

(2) Amounts for 2020 include proceeds from a multi-year supply agreement related to the sale of certain NGL terminals in April 2020. Amounts for 2019 include proceeds associated with the formation of Red River Pipeline Company LLC in May 2019. See Note 7 and Note 12 to our Consolidated Financial Statements for additional information.

Ongoing Activities Related to Strategic Transactions

We are continuously engaged in the evaluation of potential transactions that support our current business strategy. In the past, such transactions have included the sale of non-core assets, the sale of partial interests in assets to strategic joint venture partners, acquisitions and large investment capital projects. With respect to a potential divestiture or acquisition, we may conduct an auction process or participate in an auction process conducted by a third party or we may negotiate a transaction with one or a limited number of potential buyers (in the case of a divestiture) or sellers (in the case of an acquisition). Such transactions 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. 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 and acquisitions involve risks that may adversely affect our business.”

Financing Activities

Our financing activities primarily relate to funding investment capital projects, acquisitions and refinancing of our debt maturities, as well as short-term working capital (including borrowings for NYMEX and ICE margin deposits) and hedged inventory borrowings related to our NGL business and contango market activities.

Borrowings and Repayments Under Credit Arrangements

During the year ended December 31, 2021, we had net repayments under our credit facilities and commercial paper program of $712 million. The net repayments resulted primarily from cash flow from operating activities and proceeds from asset sales, which offset borrowings during the period related to funding needs for capital investments, inventory purchases and other general partnership purposes.

During the year ended December 31, 2020, we had net borrowings under our credit facilities and commercial paper program of $296 million. The net borrowings resulted primarily from borrowings during the period related to funding needs for inventory purchases and general partnership purposes.

During the year ended December 31, 2019, we had net borrowings under our credit facilities and commercial paper program of $418 million. The net borrowings resulted primarily from borrowings during the period related to funding needs for general partnership purposes.

In connection with the sale of our Pine Prairie and Southern Pines natural gas storage facilities in August 2021, we repaid our two GO Zone term loans totaling $200 million. See Note 7 for additional information regarding the sale of our natural gas storage facilities.

Senior Notes

Issuances of Senior Notes. We did not issue any senior unsecured notes during 2021. During 2020 and 2019, we issued senior unsecured notes as summarized in the table below (in millions):

Year	Description	Maturity	Face Value	Gross Proceeds[1]	Net Proceeds[2]
2020	3.80% Senior Notes issued at 99.794% of face value	September 2030	$ 750	$ 748	$ 742 [3]
2019	3.55% Senior Notes issued at 99.801% of face value	December 2029	$ 1,000	$ 998	$ 989 [4]

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

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

(3) We used the net proceeds from the offering to repay the principal amounts of our 5.00% senior notes due February 2021.

(4) We used the net proceeds from the offering to partially repay the principal amounts of our 2.60% senior notes due December 2019 and 5.75% senior notes due January 2020 and for general partnership purposes.

Repayments of Senior Notes. We did not repay any senior unsecured notes during 2021. During 2020 and 2019, we repaid the following senior unsecured notes in full (in millions):

Year	Description	Repayment Date	
2020	$600 million 5.00% Senior Notes due February 2021	November 2020	(1)
2019	$500 million 2.60% Senior Notes due December 2019	November 2019	(2)
2019	$500 million 5.75% Senior Notes due January 2020	December 2019	(2)

(1) We repaid these senior notes with proceeds from our 3.80% senior notes issued in June 2020 and cash on hand.

(2) We repaid these senior notes with proceeds from our 3.55% senior notes issued in September 2019 and cash on hand.

Additionally, during the year ended December 31, 2020, we repurchased $17 million of our outstanding senior notes on the open market and recognized a gain of $3 million on these transactions.

In January 2022, we provided notice of our intention to redeem our 3.65% senior notes due June 2022 early, on March 1, 2022.

Registration Statements

We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to a specified amount of debt or equity securities ("Traditional Shelf"), under which we had approximately $1.1 billion of unsold securities available at December 31, 2021. We also have access to a universal shelf registration statement ("WKSI Shelf"), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The offerings of our $750 million, 3.80% senior notes in June 2020 and $1.0 billion, 3.55% senior notes in September 2019 were conducted under our WKSI Shelf.

Common Equity Repurchase Program

In November 2020, the board of directors of PAGP GP approved a $500 million common equity repurchase program (the "Program") to be utilized as an additional method of returning capital to investors. The Program authorizes the repurchase from time to time of up to $500 million of our common units and/or PAGP Class A shares via open market purchases or negotiated transactions conducted in accordance with applicable regulatory requirements. Ultimately, the amount, timing and pace of potential repurchase activity will be determined by a number of factors, including market conditions, our financial performance and flexibility, actual and expected Free Cash Flow after distributions, the absolute and relative equity prices of our common units and PAGP Class A shares, and the extent to which we are positioned to achieve and maintain our targeted leverage ratio. No time limit has been set for completion of the Program, and the Program may be suspended or discontinued at any time. The Program does not obligate us or PAGP to acquire a particular number of common units or PAGP Class A shares. Any common units or PAGP Class A shares that are repurchased will be canceled.

We repurchased 18.1 million and 6.2 million common units under the Program through open market purchases that settled during the years ended December 31, 2021 and 2020, respectively, for a total purchase price of $178 million and $50 million respectively, including commissions and fees. The remaining available capacity under the Program as of December 31, 2021 was $272 million.

Distributions to Our Unitholders

In accordance with our partnership agreement, after making distributions to holders of our outstanding preferred units, we distribute the remainder of our available cash to our common unitholders of record within 45 days following the end of each quarter. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. Our levels of financial reserves are established by our general partner and include reserves for the proper conduct of our business (including future capital expenditures and anticipated credit needs), compliance with legal or contractual obligations and funding of future distributions to our Series A and Series B preferred unitholders. Our available cash also includes cash on hand resulting from borrowings made after the end of the quarter. See Item 5. "Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy" for additional discussion regarding distributions.

Distributions to our Series A preferred unitholders. Holders of our Series A preferred units are entitled to receive quarterly distributions, subject to customary anti-dilution adjustments, of $0.525 per unit ($2.10 per unit annualized). Subject to certain limitations, following January 28, 2021, the holders of our Series A preferred units may make a one-time election to reset the distribution rate. See Note 12 to our Consolidated Financial Statements for additional information.

Distributions to our Series B preferred unitholders. Holders of our Series B preferred units are entitled to receive, when, as and if declared by our general partner out of legally available funds for such purpose, cumulative cash distributions, as applicable. Through and including November 15, 2022, holders are entitled to a distribution equal to $61.25 per unit per year, payable semiannually in arrears on the 15th day of May and November. See Note 12 to our Consolidated Financial Statements for further discussion of our Series B preferred units, including distribution rates and payment dates after November 15, 2022.

Distributions to our common unitholders. On February 14, 2022, we paid a quarterly distribution of $0.18 per common unit ($0.72 per common unit on an annualized basis). The total distribution of $127 million was paid to common unitholders of record as of January 31, 2022, with respect to the quarter ended December 31, 2021. See Note 12 to our Consolidated Financial Statements for details of distributions paid during the three years ended December 31, 2021.

Distributions to Noncontrolling Interests

Distributions to noncontrolling interests represent amounts paid on interests in consolidated entities that are not owned by us. As of December 31, 2021, noncontrolling interests in our subsidiaries consisted of (i) a 35% interest in the Permian JV and (ii) a 33% interest in Red River Pipeline LLC. See Note 12 to our Consolidated Financial Statements for details of distributions paid to noncontrolling interests in Red River Pipeline LLC during the three years ended December 31, 2021.

The initial distribution from the Permian JV of approximately $155 million was paid during the first quarter of 2022, with 65% of the distribution paid to us and 35% to noncontrolling interests. Subsequent distributions will be allocated based on a modified sharing arrangement. See Note 7 to our Consolidated Financial Statements for additional information.

Contingencies

For a discussion of contingencies that may impact us, see Note 19 to our Consolidated Financial Statements.

Commitments

See Note 11 to our Consolidated Financial Statements for information regarding our debt obligations and Note 19 for information regarding our leases and other commitments.

Purchase Obligations

In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to 14 years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

The following table includes our best estimate and the timing of these payments as of December 31, 2021 (in millions):

	2022	2023	2024	2025	2026	2027 and Thereafter	Total
Crude oil, NGL and other purchases [1]	$ 22,842	$ 20,165	$ 19,215	$ 16,022	$ 15,215	$ 47,079	$ 140,538

(1) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2021. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our merchant activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil, NGL and natural gas. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At December 31, 2021 and 2020, we had outstanding letters of credit of approximately $98 million and $129 million, respectively.

Off-Balance Sheet Arrangements

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

Investments in Unconsolidated Entities

We have invested in entities that are not consolidated in our financial statements. Certain of these entities are borrowers under credit facilities. We are neither a co-borrower nor a guarantor under these credit facilities. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2021 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	20%	$ 832	$ 31	$ —
Cactus II Pipeline LLC	Crude Oil Pipeline [(1)]	65%	$ 1,129	$ 45	$ —
Capline Pipeline Company LLC	Crude Oil Pipeline	54%	$ 1,238	$ 9	$ —
Diamond Pipeline LLC	Crude Oil Pipeline [(1)]	50%	$ 915	$ 11	$ —
Eagle Ford Pipeline LLC	Crude Oil Pipeline [(1)]	50%	$ 789	$ 33	$ —
Eagle Ford Terminals Corpus Christi LLC	Crude Oil Terminal and Dock [(1)]	50%	$ 217	$ 5	$ —
OMOG JV LLC	Crude Oil Pipeline [(1)]	40%	$ 344	$ 10	$ 5
Saddlehorn Pipeline Company, LLC	Crude Oil Pipeline	30%	$ 639	$ 31	$ —
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%	$ 463	$ 10	$ —
Wink to Webster Pipeline LLC	Crude Oil Pipeline	16%	$ 2,058	$ 9	$ —
Other investments			$ 764	$ 39	$ 2

(1) We serve as operator of the asset.

Critical Accounting Policies and Estimates

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

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

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

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

In October 2021, we and Oryx Midstream completed the formation of the Permian JV. See Note 7 to our Consolidated Financial Statements for discussion of the methods, assumptions and estimates used in the determination of the fair value of the assets and liabilities acquired and identification of associated intangible assets.

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

We also have embedded derivatives that are recorded at fair value on our Consolidated Balance Sheets. These embedded derivatives are valued using models that contain inputs, some of which involve management judgment.

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

Accruals and Contingent Liabilities. We record accruals or liabilities for, among other things, environmental remediation, potential legal claims or settlements and fees for legal services associated with loss contingencies, and bonuses. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, the duration of the natural resource damage assessment and the ultimate amount of damages determined, the determination and calculation of fines and penalties, the possibility of existing legal claims giving rise to additional claims and the nature, extent and cost of legal services that will be required in connection with lawsuits, claims and other matters. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A hypothetical variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $21 million. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

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

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

See Note 6 and Note 10 to our Consolidated Financial Statements for additional information on our property and equipment and depreciation and amortization expense. See Note 2 to our Consolidated Financial Statements for additional information on our asset retirement obligations.

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

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

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

Investments in unconsolidated entities accounted for under the equity method of accounting are assessed for impairment when events or circumstances suggest that a decline in value may be other than temporary. Examples of such events or circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's core business. When it is determined that an indicated impairment is other than temporary, a charge is recognized for the difference between the investment's carrying amount and its estimated fair value. We consider the fair value estimate used to calculate the impairment of investments in unconsolidated entities a critical accounting estimate. In determining the existence of an other-than-temporary impairment of carrying value, we make a number of subjective assumptions as to:

- whether there is an event or circumstance that may be indicative of a decline in value of the investment;
- whether the decline in value is other than temporary; and
- the fair value of the investment.

Intangible assets with indefinite lives are not amortized but are instead periodically assessed for impairment. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Impairment testing entails estimating future net cash flows relating to the business, based on management's estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. In addition, changes in our weighted average cost of capital from our estimates could have a significant impact on fair value. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Resolutions of these uncertainties have resulted, and in the future may result, in impairments that impact our results of operations and financial condition.

A change in our outlook or use could result in impairments that may be material to our results of operations or financial condition. See "—Executive Summary— Market Overview and Outlook" and Note 6, Note 9 and Note 10 to our Consolidated Financial Statements for additional information.

Inventory Valuations. Inventory, including long-term inventory, primarily consists of crude oil and NGL and is valued at the lower of cost or net realizable value, with cost determined using an average cost method within specific inventory pools. At the end of each reporting period, we assess the carrying value of our inventory and use estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact our estimates are the applicable quality and location differentials to include in our net realizable value analysis. Additionally, we estimate the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value. During the years ended December 31, 2020 and 2019, we recorded charges of $233 million and $11 million, respectively, related to the valuation adjustment of our crude oil inventory due to declines in prices. See Note 5 to our Consolidated Financial Statements for further discussion regarding inventory.

Recent Accounting Pronouncements

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

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

- *Crude oil*

  We utilize crude oil derivatives to hedge commodity price risk inherent in our pipeline and merchant activities. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory and basis differentials. We manage these exposures with various instruments including futures, forwards, swaps and options.

- *Natural gas*

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

- *NGL and other*

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

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

The fair value of our commodity derivatives and the change in fair value as of December 31, 2021 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil	$ (15)	$ (41)	$ 41
Natural gas	18	$ 19	$ (19)
NGL and other	(146)	$ (78)	$ 78
Total fair value	$ (143)		

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

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time, we use interest rate derivatives to hedge interest rate risk associated with anticipated interest payments and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. We did not have any variable rate debt outstanding at December 31, 2021. The average interest rate on variable rate debt that was outstanding during the year ended December 31, 2021 was 0.8%, based upon rates in effect during the year. The fair value of our interest rate derivatives was an asset of $65 million as of December 31, 2021. A 10% increase in the forward LIBOR curve as of December 31, 2021 would have resulted in an increase of $16 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2021 would have resulted in a decrease of $16 million to the fair value of our interest rate derivatives. See Note 13 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Preferred Distribution Rate Reset Option

The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value in our Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including our common unit price, ten-year United States treasury rates, default probabilities and timing estimates to ultimately calculate the fair value of our Series A preferred units with and without the Preferred Distribution Rate Reset Option. The fair value of this embedded derivative was less than $1 million as of December 31, 2021. A 10% increase or decrease in the fair value would have an impact of less than $1 million. See Note 13 to our Consolidated Financial Statements for a discussion of embedded derivatives.

Item 8. *Financial Statements and Supplementary Data*

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

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

None.

Item 9A. *Controls and Procedures*

Disclosure Controls and Procedures

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

Applicable SEC rules require an evaluation of the effectiveness of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our DCP as of December 31, 2021, the end of the period covered by this report, and, based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our DCP is effective.

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. "Internal control over financial reporting" is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2021. See "Management's Report on Internal Control Over Financial Reporting" on page F-2 of our Consolidated Financial Statements.

Our independent registered public accounting firm, PricewaterhouseCoopers LLP, assessed the effectiveness of our internal control over financial reporting, as stated in the firm's report. See "Report of Independent Registered Public Accounting Firm" on page F-3 of our Consolidated Financial Statements.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting during the fourth quarter of 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

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

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2021 that has not previously been reported.