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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2021

or

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

Commission File Number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**76-0582150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

333 Clay Street, Suite 1600
Houston, Texas 77002
(Address of principal executive offices) (Zip code)
(713) 646-4100
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	PAA	Nasdaq

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☑ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☑ Yes ☐ No

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

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

As of October 29, 2021, there were 711,121,882 Common Units outstanding.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except unit data)

	September 30, 2021	December 31, 2020
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 191	$ 22
Restricted cash	3	38
Trade accounts receivable and other receivables, net	3,765	2,553
Inventory	681	647
Other current assets	234	405
Total current assets	4,874	3,665
PROPERTY AND EQUIPMENT	17,283	18,585
Accumulated depreciation	(4,199)	(3,974)
Property and equipment, net	13,084	14,611
OTHER ASSETS		
Investments in unconsolidated entities	3,710	3,764
Linefill and base gas	901	982
Long-term operating lease right-of-use assets, net	374	378
Long-term inventory	221	130
Other long-term assets, net	1,033	967
Total assets	$ 24,197	$ 24,497
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Trade accounts payable	$ 3,873	$ 2,437
Short-term debt	808	831
Other current liabilities	716	985
Total current liabilities	5,397	4,253
LONG-TERM LIABILITIES		
Senior notes, net	8,327	9,071
Other long-term debt, net	61	311
Long-term operating lease liabilities	326	317
Other long-term liabilities and deferred credits	789	807
Total long-term liabilities	9,503	10,506
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
PARTNERS' CAPITAL		
Series A preferred unitholders (71,090,468 and 71,090,468 units outstanding, respectively)	1,505	1,505
Series B preferred unitholders (800,000 and 800,000 units outstanding, respectively)	787	787
Common unitholders (711,121,882 and 722,380,416 units outstanding, respectively)	6,860	7,301
Total partners' capital excluding noncontrolling interests	9,152	9,593
Noncontrolling interests	145	145
Total partners' capital	9,297	9,738
Total liabilities and partners' capital	$ 24,197	$ 24,497

The accompanying notes are an integral part of these condensed consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 10,515	$ 5,537	$ 28,221	$ 16,370
Transportation segment revenues	133	146	432	484
Facilities segment revenues	128	150	436	473
Total revenues	10,776	5,833	29,089	17,327
COSTS AND EXPENSES				
Purchases and related costs	10,074	5,107	26,743	15,000
Field operating costs	274	254	746	811
General and administrative expenses	67	61	205	201
Depreciation and amortization	178	160	551	493
(Gains)/losses on asset sales and asset impairments, net	221	(2)	592	617
Goodwill impairment losses	—	—	—	2,515
Total costs and expenses	10,814	5,580	28,837	19,637
OPERATING INCOME/(LOSS)	(38)	253	252	(2,310)
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	69	89	190	280
Gain on/(impairment of) investments in unconsolidated entities, net	—	(91)	—	(182)
Interest expense (net of capitalized interest of $4, $6, $14 and $17, respectively)	(106)	(113)	(319)	(329)
Other income/(expense), net	(10)	5	13	(7)
INCOME/(LOSS) BEFORE TAX	(85)	143	136	(2,548)
Current income tax expense	(8)	(17)	(11)	(39)
Deferred income tax benefit	38	20	27	32
NET INCOME/(LOSS)	(55)	146	152	(2,555)
Net income attributable to noncontrolling interests	(4)	(3)	(9)	(7)
NET INCOME/(LOSS) ATTRIBUTABLE TO PAA	$ (59)	$ 143	$ 143	$ (2,562)
NET INCOME/(LOSS) PER COMMON UNIT (NOTE 4):				
Net income/(loss) allocated to common unitholders — Basic and Diluted	$ (109)	$ 93	$ (7)	$ (2,712)
Basic and diluted weighted average common units outstanding	715	728	719	728
Basic and diluted net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.01)	$ (3.72)

The accompanying notes are an integral part of these condensed consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)
(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(unaudited)		(unaudited)	
Net income/(loss)	$ (55)	$ 146	$ 152	$ (2,555)
Other comprehensive income/(loss)	(44)	82	64	(129)
Comprehensive income/(loss)	(99)	228	216	(2,684)
Comprehensive income attributable to noncontrolling interests	(4)	(3)	(9)	(7)
Comprehensive income/(loss) attributable to PAA	$ (103)	$ 225	$ 207	$ (2,691)

The accompanying notes are an integral part of these condensed consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)
(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
	(unaudited)			
Balance at December 31, 2020	$ (258)	$ (657)	$ (3)	$ (918)
Reclassification adjustments	28	—	—	28
Unrealized gain on hedges	36	—	—	36
Currency translation adjustments	—	1	—	1
Other	—	—	(1)	(1)
Total period activity	64	1	(1)	64
Balance at September 30, 2021	$ (194)	$ (656)	$ (4)	$ (854)

	Derivative Instruments	Translation Adjustments	Other	Total
	(unaudited)			
Balance at December 31, 2019	$ (259)	$ (674)	$ —	$ (933)
Reclassification adjustments	8	—	—	8
Unrealized loss on hedges	(39)	—	—	(39)
Currency translation adjustments	—	(99)	—	(99)
Other	—	—	1	1
Total period activity	(31)	(99)	1	(129)
Balance at September 30, 2020	$ (290)	$ (773)	$ 1	$ (1,062)

The accompanying notes are an integral part of these condensed consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income/(loss)	$ 152	$ (2,555)
Reconciliation of net income/(loss) to net cash provided by operating activities:		
Depreciation and amortization	551	493
(Gains)/losses on asset sales and asset impairments, net	592	617
Goodwill impairment losses	—	2,515
Inventory valuation adjustments	—	233
Deferred income tax benefit	(27)	(32)
Settlement of terminated interest rate hedging instruments	—	(100)
Change in fair value of Preferred Distribution Rate Reset Option (Note 8)	(13)	(7)
Equity earnings in unconsolidated entities	(190)	(280)
Distributions on earnings from unconsolidated entities	322	344
(Gain on)/impairment of investments in unconsolidated entities, net	—	182
Other	42	37
Changes in assets and liabilities, net of acquisitions	(68)	(191)
Net cash provided by operating activities	1,361	1,256
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(32)	(310)
Investments in unconsolidated entities	(78)	(386)
Additions to property, equipment and other	(257)	(606)
Proceeds from sales of assets	878	246
Other investing activities	(33)	(10)
Net cash provided by/(used in) investing activities	478	(1,066)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) under commercial paper program (Note 6)	(546)	19
Net repayments under senior secured hedged inventory facility (Note 6)	(167)	(325)
Repayment of GO Zone term loans (Note 6)	(200)	—
Proceeds from the issuance of senior notes	—	748
Repayments of senior notes	—	(17)
Repurchase of common units (Note 7)	(117)	—
Distributions paid to Series A preferred unitholders (Note 7)	(112)	(112)
Distributions paid to Series B preferred unitholders (Note 7)	(25)	(25)
Distributions paid to common unitholders (Note 7)	(389)	(524)
Other financing activities	(151)	19
Net cash used in financing activities	(1,707)	(217)
Effect of translation adjustment	2	(9)
Net increase/(decrease) in cash and cash equivalents and restricted cash	134	(36)
Cash and cash equivalents and restricted cash, beginning of period	60	82
Cash and cash equivalents and restricted cash, end of period	$ 194	$ 46
Cash paid for:		
Interest, net of amounts capitalized	$ 265	$ 285
Income taxes, net of amounts refunded	$ 32	$ 72

The accompanying notes are an integral part of these condensed consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(in millions)

	Limited Partners					
	Preferred Unitholders					
	Series A	Series B	Common Unitholders	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	(unaudited)					
Balance at December 31, 2020	$ 1,505	$ 787	$ 7,301	$ 9,593	$ 145	$ 9,738
Net income/(loss)	112	37	(6)	143	9	152
Distributions (Note 7)	(112)	(37)	(389)	(538)	(10)	(548)
Other comprehensive income	—	—	64	64	—	64
Repurchase of common units (Note 7)	—	—	(117)	(117)	—	(117)
Contributions from noncontrolling interests	—	—	—	—	1	1
Other	—	—	7	7	—	7
Balance at September 30, 2021	$ 1,505	$ 787	$ 6,860	$ 9,152	$ 145	$ 9,297

	Limited Partners					
	Preferred Unitholders					
	Series A	Series B	Common Unitholders	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	(unaudited)					
Balance at June 30, 2021	$ 1,505	$ 787	$ 7,203	$ 9,495	$ 145	$ 9,640
Net income/(loss)	37	12	(108)	(59)	4	(55)
Distributions (Note 7)	(37)	(12)	(129)	(178)	(4)	(182)
Other comprehensive loss	—	—	(44)	(44)	—	(44)
Repurchase of common units (Note 7)	—	—	(64)	(64)	—	(64)
Other	—	—	2	2	—	2
Balance at September 30, 2021	$ 1,505	$ 787	$ 6,860	$ 9,152	$ 145	$ 9,297

The accompanying notes are an integral part of these condensed consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(continued)
(in millions)

	Limited Partners			Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Preferred Unitholders		Common Unitholders			
	Series A	Series B				
	(unaudited)					
Balance at December 31, 2019	$ 1,505	$ 787	$ 10,770	$ 13,062	$ 133	$ 13,195
Net income/(loss)	112	37	(2,711)	(2,562)	7	(2,555)
Distributions	(112)	(37)	(524)	(673)	(6)	(679)
Other comprehensive loss	—	—	(129)	(129)	—	(129)
Contributions from noncontrolling interests	—	—	—	—	11	11
Other	—	—	8	8	—	8
Balance at September 30, 2020	$ 1,505	$ 787	$ 7,414	$ 9,706	$ 145	$ 9,851

	Limited Partners			Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Preferred Unitholders		Common Unitholders			
	Series A	Series B				
	(unaudited)					
Balance at June 30, 2020	$ 1,505	$ 787	$ 7,367	$ 9,659	$ 143	$ 9,802
Net income	37	12	94	143	3	146
Distributions	(37)	(12)	(131)	(180)	(2)	(182)
Other comprehensive income	—	—	82	82	—	82
Contributions from noncontrolling interests	—	—	—	—	1	1
Other	—	—	2	2	—	2
Balance at September 30, 2020	$ 1,505	$ 787	$ 7,414	$ 9,706	$ 145	$ 9,851

The accompanying notes are an integral part of these condensed consolidated financial statements.

Note 1—Organization and Basis of Consolidation and Presentation

Organization

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

Our business model integrates large-scale supply aggregation capabilities with the ownership and operation of critical midstream infrastructure systems that connect major producing regions to key demand centers and export terminals. As one of the largest midstream service providers in North America, we own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and natural gas liquids (“NGL”) producing basins (including the Permian Basin) and transportation corridors and at major market hubs in the United States and Canada. Our assets and the services we provide are primarily focused on crude oil and NGL. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 11 for further discussion of our operating segments.

Our non-economic general partner interest is held by PAA GP LLC (“PAA GP”), a Delaware limited liability company, whose sole member is Plains AAP, L.P. (“AAP”), a Delaware limited partnership. In addition to its ownership of PAA GP, as of September 30, 2021, AAP also owned a limited partner interest in us through its ownership of approximately 245.0 million of our common units (approximately 31% of our total outstanding common units and Series A preferred units combined). Plains All American GP LLC (“GP LLC”), a Delaware limited liability company, is AAP’s general partner. Plains GP Holdings, L.P. (“PAGP”) is the sole and managing member of GP LLC, and, at September 30, 2021, owned an approximate 79% limited partner interest in AAP. PAA GP Holdings LLC (“PAGP GP”) is the general partner of PAGP.

As the sole member of GP LLC, PAGP has responsibility for conducting our business and managing our operations; however, the board of directors of PAGP GP has ultimate responsibility for managing the business and affairs of PAGP, AAP and us. GP LLC employs our domestic officers and personnel; our Canadian officers and personnel are employed by our subsidiary, Plains Midstream Canada ULC.

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

Definitions

Additional defined terms are used in this Form 10-Q and shall have the meanings indicated below:

AOCI	=	Accumulated other comprehensive income/(loss)
ASC	=	Accounting Standards Codification
ASU	=	Accounting Standards Update
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
CODM	=	Chief Operating Decision Maker
EBITDA	=	Earnings before interest, taxes, depreciation and amortization
EPA	=	United States Environmental Protection Agency
FASB	=	Financial Accounting Standards Board
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	Intercontinental Exchange
ISDA	=	International Swaps and Derivatives Association
LIBOR	=	London Interbank Offered Rate
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MMbls	=	Million barrels
NGL	=	Natural gas liquids, including ethane, propane and butane
NYMEX	=	New York Mercantile Exchange
SEC	=	United States Securities and Exchange Commission
TWh	=	Terawatt hour
USD	=	United States dollar
WTI	=	West Texas Intermediate

Basis of Consolidation and Presentation

The accompanying unaudited condensed consolidated interim financial statements and related notes thereto should be read in conjunction with our 2020 Annual Report on Form 10-K. The accompanying condensed consolidated financial statements include the accounts of PAA and all of its wholly owned subsidiaries and those entities that it controls. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We apply proportionate consolidation for pipelines and other assets in which we own undivided joint interests. The financial statements have been prepared in accordance with the instructions for interim reporting as set forth by the SEC. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation.

The condensed consolidated balance sheet data as of December 31, 2020 was derived from audited financial statements, but does not include all disclosures required by GAAP. The results of operations for the three and nine months ended September 30, 2021 should not be taken as indicative of results to be expected for the entire year.

Subsequent events have been evaluated through the financial statements issuance date and have been included in the following footnotes where applicable.

Note 2—Summary of Significant Accounting Policies

Restricted Cash

Restricted cash includes cash held by us that is unavailable for general use and is comprised of amounts advanced to us by certain equity method investees related to the construction of fixed assets where we serve as construction manager. The following table presents a reconciliation of cash and cash equivalents and restricted cash reported on our Condensed Consolidated Balance Sheets that sum to the total of the amounts shown on our Condensed Consolidated Statements of Cash Flows (in millions):

	September 30, 2021	December 31, 2020
Cash and cash equivalents	$ 191	$ 22
Restricted cash	3	38
Total cash and cash equivalents and restricted cash	$ 194	$ 60

Property and Equipment

During the first quarter of 2021, we modified the useful lives of certain of our Pipelines and related facilities and Storage, terminal and rail facilities to useful lives of 10 to 50 years from useful lives of 10 to 70 years to reflect current expectations given our future operating and commercial outlook. These depreciable life adjustments will prospectively increase depreciation expense. For the three and nine months ended September 30, 2021, these reductions in useful lives increased depreciation expense by approximately $18 million and $54 million, respectively, which resulted in a decrease to both basic and diluted net income per common unit of approximately $0.02 for the three months ended September 30, 2021 and approximately $0.07 for the nine months ended September 30, 2021 from what these amounts would have been absent the change in useful lives.

Recent Accounting Pronouncements

Except as discussed below and in our 2020 Annual Report on Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the nine months ended September 30, 2021 that are of significance or potential significance to us.

Accounting Standards Updates Adopted During the Period

We adopted the following ASUs during the period:

- ASU 2019-12, Income Taxes (Topic 740): *Simplifying the Accounting for Income Taxes*. See Note 2 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for additional information regarding this ASU. We adopted this ASU effective January 1, 2021 and our adoption did not have a material impact on our financial position, results of operations or cash flows.

- ASU 2021-05, Leases (Topic 842): *Lessors - Certain Leases with Variable Lease Payments*. Issued by the FASB in July 2021, ASU 2021-05 modifies the lease classification requirements for lessors in Topic 842, which we adopted on the effective date of January 1, 2019. The amendments require lessors to classify and account for a lease with variable lease payments that do not depend on a reference index or a rate as an operating lease at lease commencement if another classification (i.e., sales-type or direct financing) would result in the recognition of a day-one loss. For entities that have adopted Topic 842, the guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2021, with early adoption permitted. We have elected to early adopt the guidance on a prospective basis as of July 1, 2021. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

Note 3—Revenues and Accounts Receivable

Revenue Recognition

We disaggregate our revenues by segment and type of activity. These categories depict how the nature, amount, timing and uncertainty of revenues and cash flows are affected by economic factors. See Note 3 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for additional information regarding our types of revenues and policies for revenue recognition.

The following tables present our Supply and Logistics, Transportation and Facilities segment revenues from contracts with customers disaggregated by type of activity (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Supply and Logistics segment revenues from contracts with customers				
Crude oil transactions	$ 10,417	$ 5,394	$ 27,747	$ 15,644
NGL and other transactions	310	180	1,279	736
Total Supply and Logistics segment revenues from contracts with customers	$ 10,727	$ 5,574	$ 29,026	$ 16,380

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Transportation segment revenues from contracts with customers				
Tariff activities:				
Crude oil pipelines	$ 479	$ 442	$ 1,338	$ 1,360
NGL pipelines	26	26	79	77
Total tariff activities	505	468	1,417	1,437
Trucking	18	20	60	77
Total Transportation segment revenues from contracts with customers	$ 523	$ 488	$ 1,477	$ 1,514

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Facilities segment revenues from contracts with customers				
Crude oil, NGL and other terminalling and storage	$ 143	$ 178	$ 466	$ 536
NGL and natural gas processing and fractionation	68	76	211	265
Rail load / unload	4	8	24	30
Total Facilities segment revenues from contracts with customers	$ 215	$ 262	$ 701	$ 831

Reconciliation to Total Revenues of Reportable Segments. The following disclosures only include information regarding revenues associated with consolidated entities; revenues from entities accounted for by the equity method are not included. The following tables present the reconciliation of our revenues from contracts with customers (as described above for each segment) to segment revenues and total revenues as disclosed in our Condensed Consolidated Statements of Operations (in millions):

Three Months Ended September 30, 2021	Transportation	Facilities	Supply and Logistics	Total
Revenues from contracts with customers	$ 523	$ 215	$ 10,727	$ 11,465
Other items in revenues	6	11	(212)	(195)
Total revenues of reportable segments	$ 529	$ 226	$ 10,515	$ 11,270
Intersegment revenues				(494)
Total revenues				$ 10,776

Three Months Ended September 30, 2020	Transportation	Facilities	Supply and Logistics	Total
Revenues from contracts with customers	$ 488	$ 262	$ 5,574	$ 6,324
Other items in revenues	6	9	(37)	(22)
Total revenues of reportable segments	$ 494	$ 271	$ 5,537	$ 6,302
Intersegment revenues				(469)
Total revenues				$ 5,833

Nine Months Ended September 30, 2021	Transportation	Facilities	Supply and Logistics	Total
Revenues from contracts with customers	$ 1,477	$ 701	$ 29,026	$ 31,204
Other items in revenues	91	40	(804)	(673)
Total revenues of reportable segments	$ 1,568	$ 741	$ 28,222	$ 30,531
Intersegment revenues				(1,442)
Total revenues				$ 29,089

Nine Months Ended September 30, 2020	Transportation	Facilities	Supply and Logistics	Total
Revenues from contracts with customers	$ 1,514	$ 831	$ 16,380	$ 18,725
Other items in revenues	16	29	(9)	36
Total revenues of reportable segments	$ 1,530	$ 860	$ 16,371	$ 18,761
Intersegment revenues				(1,434)
Total revenues				$ 17,327

Minimum Volume Commitments. We have certain agreements that require counterparties to transport or throughput a minimum volume over an agreed upon period. The following table presents counterparty deficiencies associated with contracts with customers and buy/sell arrangements that include minimum volume commitments for which we had remaining performance obligations and the customers still had the ability to meet their obligations (in millions):

Counterparty Deficiencies	Financial Statement Classification	September 30, 2021	December 31, 2020
Billed and collected	Liability	$ 102	$ 73
Unbilled [(1)]	N/A	16	4
Total		$ 118	$ 77

(1) Amounts were related to deficiencies for which the counterparties had not met their contractual minimum commitments and are not reflected in our Condensed Consolidated Financial Statements as we had not yet billed or collected such amounts.

Contract Balances. Our contract balances consist of amounts received associated with services or sales for which we have not yet completed the related performance obligation. The following table presents the change in the liability balance associated with contracts with customers (in millions):

	Contract Liabilities
Balance at December 31, 2020	$ 501
Amounts recognized as revenue [(1)]	(386)
Additions	17
Balance at September 30, 2021	$ 132

(1) Includes approximately $361 million associated with crude oil sales agreements that were entered into in the fourth quarter of 2020 in conjunction with storage arrangements and inventory exchanges, which were settled in the first quarter of 2021.

Remaining Performance Obligations. The information below includes the amount of consideration allocated to partially and wholly unsatisfied remaining performance obligations under contracts that exist as of the end of the periods and the timing of revenue recognition of those remaining performance obligations. Certain contracts meet the requirements for the presentation as remaining performance obligations. These arrangements include a fixed minimum level of service, typically a set volume of service, and do not contain any variability other than expected timing within a limited range. The following table presents the amount of consideration associated with remaining performance obligations for the population of contracts with external customers meeting the presentation requirements as of September 30, 2021 (in millions):

	Remainder of 2021	2022	2023	2024	2025	2026 and Thereafter
Pipeline revenues supported by minimum volume commitments and capacity agreements [(1)]	$ 47	$ 174	$ 174	$ 155	$ 129	$ 461
Storage, terminalling and throughput agreement revenues	69	233	165	126	60	230
Total	$ 116	$ 407	$ 339	$ 281	$ 189	$ 691

(1) Calculated as volumes committed under contracts multiplied by the current applicable tariff rate.

The presentation above does not include (i) expected revenues from legacy shippers not underpinned by minimum volume commitments, including pipelines where there are no or limited alternative pipeline transportation options, (ii) intersegment revenues and (iii) the amount of consideration associated with certain income generating contracts, which include a fixed minimum level of service, that are either not within the scope of ASC 606 or do not meet the requirements for presentation as remaining performance obligations. The following are examples of contracts that are not included in the table above because they are not within the scope of ASC 606 or do not meet the requirements for presentation:

- Minimum volume commitments on certain of our joint venture pipeline systems;
- Acreage dedications;
- Supply and Logistics buy/sell arrangements with future committed volumes;
- All other Supply and Logistics contracts, due to the election of practical expedients related to variable consideration and short-term contracts;
- Transportation and Facilities contracts that are short-term;
- Contracts within the scope of ASC 842, *Leases*; and
- Contracts within the scope of ASC 815, *Derivatives and Hedging*.

Trade Accounts Receivable and Other Receivables, Net

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL. These purchasers include, but are not limited to, refiners, producers, marketing and trading companies and financial institutions. The majority of our accounts receivable relate to our crude oil supply and logistics activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

During 2020, 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 has caused liquidity issues impacting many energy companies, which in turn has increased the potential credit risks associated with certain counterparties with which we do business. To mitigate credit risk related to our accounts receivable, we utilize a rigorous credit review process. We closely monitor market conditions and perform credit reviews of each customer to make a determination with respect to the amount, if any, of open credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of advance cash payments, standby letters of credit, credit insurance or parental guarantees. Additionally, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. For a majority of these net-cash arrangements, we also enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet).

Accounts receivable from the sale of crude oil are generally settled with counterparties on the industry settlement date, which is typically in the month following the month in which the title transfers. Otherwise, we generally invoice customers within 30 days of when the products or services were provided and generally require payment within 30 days of the invoice date. We review all outstanding accounts receivable balances on a monthly basis and record our receivables net of expected credit losses. We do not write-off accounts receivable balances until we have exhausted substantially all collection efforts. At September 30, 2021 and December 31, 2020, substantially all of our trade accounts receivable were less than 30 days past their invoice date. Our expected credit losses are immaterial. Although we consider our credit procedures to be adequate to mitigate any significant credit losses, the actual amount of current and future credit losses could vary significantly from estimated amounts.

The following is a reconciliation of trade accounts receivable from revenues from contracts with customers to total Trade accounts receivable and other receivables, net as presented on our Condensed Consolidated Balance Sheets (in millions):

	September 30, 2021	December 31, 2020
Trade accounts receivable arising from revenues from contracts with customers	$ 3,294	$ 2,317
Other trade accounts receivables and other receivables [(1)]	4,176	2,818
Impact due to contractual rights of offset with counterparties	(3,705)	(2,582)
Trade accounts receivable and other receivables, net	$ 3,765	$ 2,553

(1) The balance is comprised primarily of accounts receivable associated with buy/sell arrangements that are not within the scope of ASC 606.

Note 4—Net Income/(Loss) Per Common Unit

We calculate basic and diluted net income/(loss) per common unit by dividing net income/(loss) attributable to PAA (after deducting amounts allocated to preferred unitholders and participating securities) by the basic and diluted weighted average number of common units outstanding during the period. Participating securities include equity-indexed compensation plan awards that have vested distribution equivalent rights, which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

The diluted weighted average number of common units is computed based on the weighted average number of common units plus the effect of potentially dilutive securities outstanding during the period, which include (i) our Series A preferred units and (ii) our equity-indexed compensation plan awards. When applying the if-converted method prescribed by FASB guidance, the possible conversion of approximately 71 million Series A preferred units, on a weighted-average basis, were excluded from the calculation of diluted net income/(loss) per common unit for the three and nine months ended September 30, 2021 and 2020 as the effect was antidilutive for each period. Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered potentially dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive during the period are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. As a result of the hypothetical common unit repurchase, there were no potentially dilutive equity-indexed compensation awards for the three months ended September 30, 2020. For the three and nine months ended September 30, 2021 and the nine months ended September 30, 2020, approximately 0.6 million, 0.5 million and 0.4 million equity-indexed compensation plan awards, respectively, on a weighted-average basis, were excluded from the computation of diluted net loss per common unit as the effect was antidilutive. See Note 18 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for a discussion of our equity-indexed compensation plan awards.

The following table sets forth the computation of basic and diluted net income/(loss) per common unit (in millions, except per unit data):

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Basic and Diluted Net Income/(Loss) per Common Unit				
Net income/(loss) attributable to PAA	$ (59)	$ 143	$ 143	$ (2,562)
Distributions to Series A preferred unitholders	(37)	(37)	(112)	(112)
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Distributions to participating securities	(1)	(1)	(1)	(1)
Net income/(loss) allocated to common unitholders [(1)]	$ (109)	$ 93	$ (7)	$ (2,712)
Basic and diluted weighted average common units outstanding	715	728	719	728
Basic and diluted net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.01)	$ (3.72)

(1) We calculate net income/(loss) allocated to common unitholders based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings (i.e., undistributed loss), if any, are allocated to the common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.

Note 5—Inventory, Linefill and Base Gas and Long-term Inventory

Inventory, linefill and base gas and long-term inventory consisted of the following (barrels and natural gas volumes in thousands and carrying value in millions):

	September 30, 2021				December 31, 2020			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [(1)]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [(1)]
Inventory								
Crude oil	6,125	barrels	$ 376	$ 61.39	13,450	barrels	$ 441	$ 32.79
NGL	10,681	barrels	300	$ 28.09	12,302	barrels	199	$ 16.18
Other	N/A		5	N/A	N/A		7	N/A
Inventory subtotal			681				647	
Linefill and base gas								
Crude oil	15,150	barrels	856	$ 56.50	14,669	barrels	828	$ 56.45
NGL	1,636	barrels	45	$ 27.51	1,640	barrels	44	$ 26.83
Natural gas [(2)]	—	Mcf	—	$ —	25,576	Mcf	110	$ 4.30
Linefill and base gas subtotal			901				982	
Long-term inventory								
Crude oil	2,737	barrels	188	$ 68.69	2,499	barrels	111	$ 44.42
NGL	1,140	barrels	33	$ 28.95	1,185	barrels	19	$ 16.03
Long-term inventory subtotal			221				130	
Total			$ 1,803				$ 1,759	

(1) Price per unit of measure is comprised of a weighted average associated with various grades, qualities and locations. Accordingly, these prices may not coincide with any published benchmarks for such products.

(2) Base gas with a carrying value of $110 million was included in the sale of our natural gas storage facilities, which closed on August 2, 2021. See Note 12 for additional information.

Note 6—Debt

Debt consisted of the following (in millions):

	September 30, 2021	December 31, 2020
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 0.7% [1]	$ —	$ 547
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 1.2% [1]	—	167
Senior notes:		
3.65% senior notes due June 2022	750	—
Other	58	117
Total short-term debt	808	831
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $55 and $62, respectively	8,327	9,071
GO Zone term loans, net of debt issuance costs of $1, bearing a weighted-average interest rate of 1.3% [2]	—	199
Other	61	112
Total long-term debt	8,388	9,382
Total debt [3]	$ 9,196	$ 10,213

(1) We classified these commercial paper notes and credit facility borrowings as short-term as of December 31, 2020, as these notes and borrowings were primarily designated as working capital borrowings, were required to be repaid within one year and were primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

(2) The GO Zone term loans were initially assumed by one of our subsidiaries in connection with the acquisition of the Southern Pines natural gas storage facility. The loans were repaid in August 2021 in connection with the sale of that facility. See Note 12 for additional information.

(3) Our fixed-rate senior notes had a face value of approximately $9.1 billion at both September 30, 2021 and December 31, 2020. We estimated the aggregate fair value of these notes as of September 30, 2021 and December 31, 2020 to be approximately $10.0 billion and $9.9 billion, respectively. Our fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near the end of the reporting period. We estimate that the carrying value of outstanding borrowings under our credit facilities, commercial paper program and GO Zone term loans approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities, commercial paper program and GO Zone term loans are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

Credit Facilities

In August 2021, we renewed and extended our credit facilities by entering into new and amended credit agreements, as discussed further below. The covenants and events of default under the new and amended credit agreements remain substantially unchanged from the previous agreements.

Senior secured hedged inventory facility. In August 2021, we entered into an amended credit agreement which replaced our $1.4 billion senior secured hedged inventory facility scheduled to mature in August 2022 with a $1.35 billion senior secured hedged inventory facility with an initial maturity date of August 2024. Subject to obtaining additional or increased lender commitments and other terms and conditions, the committed capacity of the facility may be increased to $1.9 billion. The amended credit agreement provides for the issuance of letters of credit of up to $400 million. Proceeds from the facility are primarily used to finance purchased or stored hedged inventory, including NYMEX and ICE margin deposits. Such obligations under the committed facility are secured by the financed inventory and the associated accounts receivable and are repaid from the proceeds of the sale of the financed inventory. Borrowings accrue interest based, at our election, on certain floating rate indices as defined in the credit agreement, in each case plus a margin based on our credit rating at the applicable time. The amended credit agreement also provides for one or more one-year extensions, subject to applicable approval and other terms and conditions.

Senior unsecured revolving credit facility. In August 2021, we entered into a new unsecured credit agreement that provides for a senior unsecured revolving credit facility with a committed borrowing capacity of $1.35 billion, of which $400 million is available for the issuance of letters of credit. The new credit agreement replaced our previous credit agreement that provided for a $1.6 billion senior unsecured revolving credit facility and was scheduled to mature in August 2024. Subject to obtaining additional or increased lender commitments and other terms and conditions, the committed capacity may be increased to $2.1 billion. Borrowings accrue interest based, at our election, on certain floating rate indices as defined in the credit agreement, in each case plus a margin based on our credit rating at the applicable time. The new credit agreement has an initial maturity date of August 2026 and provides for one or more one-year extensions, subject to applicable approval and other terms and conditions.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the nine months ended September 30, 2021 and 2020 were approximately $31.2 billion and $20.2 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $31.9 billion and $20.5 billion for the nine months ended September 30, 2021 and 2020, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At September 30, 2021 and December 31, 2020, we had outstanding letters of credit of $64 million and $129 million, respectively.

Note 7—Partners' Capital and Distributions

Units Outstanding

The following tables present the activity for our preferred and common units:

	Limited Partners		
	Series A Preferred Units	Series B Preferred Units	Common Units
Outstanding at December 31, 2020	71,090,468	800,000	722,380,416
Repurchase and cancellation of common units under Common Equity Repurchase Program [(1)]	—	—	(350,000)
Issuances of common units under equity-indexed compensation plans	—	—	25,431
Outstanding at March 31, 2021	71,090,468	800,000	722,055,847
Repurchase and cancellation of common units under Common Equity Repurchase Program	—	—	(4,940,592)
Issuances of common units under equity-indexed compensation plans	—	—	256,321
Outstanding at June 30, 2021	71,090,468	800,000	717,371,576
Repurchase and cancellation of common units under Common Equity Repurchase Program	—	—	(6,626,711)
Issuances of common units under equity-indexed compensation plans	—	—	377,017
Outstanding at September 30, 2021	71,090,468	800,000	711,121,882

	Limited Partners		
	Series A Preferred Units	Series B Preferred Units	Common Units
Outstanding at December 31, 2019	71,090,468	800,000	728,028,576
Issuances of common units under equity-indexed compensation plans	—	—	24,431
Outstanding at March 31, 2020	71,090,468	800,000	728,053,007
Issuances of common units under equity-indexed compensation plans	—	—	47,391
Outstanding at June 30, 2020	71,090,468	800,000	728,100,398
Issuances of common units under equity-indexed compensation plans	—	—	376,193
Outstanding at September 30, 2020	71,090,468	800,000	728,476,591

(1) Trades for these units were executed in late December 2020, but settled in early January 2021.

Common Equity Repurchase Program

We repurchased 11,917,303 common units under our Common Equity Repurchase Program (the "Program") through open market purchases that settled during the nine months ended September 30, 2021. The total purchase price of these repurchases was $117 million, including commissions and fees. The repurchased common units were canceled immediately upon acquisition, as were the PAGP Class C shares held by us associated with the repurchased common units. At September 30, 2021, the remaining available capacity under the Program was $333 million. See Note 12 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for additional information regarding the Program.

Distributions

Series A Preferred Unit Distributions. The following table details distributions to our Series A preferred unitholders paid during or pertaining to the first nine months of 2021 (in millions, except per unit data):

	Series A Preferred Unitholders	
Distribution Payment Date	**Cash Distribution**	**Distribution per Unit**
November 12, 2021 [(1)]	$ 37	$ 0.525
August 13, 2021	$ 37	$ 0.525
May 14, 2021	$ 37	$ 0.525
February 12, 2021	$ 37	$ 0.525

(1) Payable to unitholders of record at the close of business on October 29, 2021 for the period from July 1, 2021 through September 30, 2021. At September 30, 2021, such amount was accrued as distributions payable in “Other current liabilities” on our Condensed Consolidated Balance Sheet.

Series B Preferred Unit Distributions. Distributions on our Series B preferred units are payable semi-annually in arrears on the 15th day of May and November. The following table details distributions paid to our Series B preferred unitholders (in millions, except per unit data):

	Series B Preferred Unitholders	
Distribution Payment Date	**Cash Distribution**	**Distribution per Unit**
November 15, 2021 [(1)]	$ 24.5	$ 30.625
May 17, 2021	$ 24.5	$ 30.625

(1) Payable to unitholders of record at the close of business on November 1, 2021 for the period from May 15, 2021 through November 14, 2021.

At September 30, 2021, approximately $18 million of accrued distributions payable to our Series B preferred unitholders was included in “Other current liabilities” on our Condensed Consolidated Balance Sheet.

Common Unit Distributions. The following table details distributions to our common unitholders paid during or pertaining to the first nine months of 2021 (in millions, except per unit data):

	Distributions			
	Common Unitholders			
Distribution Payment Date	**Public**	**AAP**	**Total Cash Distribution**	**Cash Distribution per Common Unit**
November 12, 2021 [(1)]	$ 84	$ 44	$ 128	$ 0.18
August 13, 2021	$ 85	$ 44	$ 129	$ 0.18
May 14, 2021	$ 86	$ 44	$ 130	$ 0.18
February 12, 2021	$ 86	$ 44	$ 130	$ 0.18

(1) Payable to unitholders of record at the close of business on October 29, 2021 for the period from July 1, 2021 through September 30, 2021.

Noncontrolling Interests in Subsidiaries

During the nine months ended September 30, 2021, we paid distributions of $10 million to noncontrolling interests in Red River Pipeline Company LLC.

Note 8—Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. We use various derivative instruments to optimize our profits while managing our exposure to (i) commodity price risk, (ii) interest rate risk and (iii) currency exchange rate risk. Our commodity price risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our derivative positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and currency exchange rate risk management policies and procedures are designed to monitor our derivative positions and ensure that those positions are consistent with our objectives and approved strategies. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on changes in commodity prices, interest rates or currency exchange rates. When we apply hedge accounting, our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. At the inception of the hedging relationship, we assess whether the derivatives employed are highly effective in offsetting changes in cash flows of anticipated hedged transactions. Throughout the hedging relationship, retrospective and prospective hedge effectiveness is assessed on a qualitative basis.

We record all open derivatives on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives designated as cash flow hedges, changes in fair value are deferred in AOCI and recognized in earnings in the periods during which the underlying hedged transactions are recognized in earnings. Derivatives that are not designated in a hedging relationship for accounting purposes are recognized in earnings each period. Cash settlements associated with our derivative activities are classified within the same category as the related hedged item in our Condensed Consolidated Statements of Cash Flows.

Our financial derivatives, used for hedging risk, are governed through ISDA master agreements and clearing brokerage agreements. These agreements include stipulations regarding the right of set off in the event that we or our counterparty default on performance obligations. If a default were to occur, both parties have the right to net amounts payable and receivable into a single net settlement between parties.

At September 30, 2021 and December 31, 2020, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings. Although we may be required to post margin on our exchange-traded derivatives transacted through a clearing brokerage account, as described below, we do not require our non-cleared derivative counterparties to post collateral with us.

Commodity Price Risk Hedging

Our core business activities involve certain commodity price-related risks that we manage in various ways, including through the use of derivative instruments. Our policy is to (i) only purchase inventory for which we have a sales market, (ii) structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold material physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be divided into the following general categories:

Commodity Purchases and Sales — In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of September 30, 2021, net derivative positions related to these activities included:

- A net long position of 10.7 million barrels associated with our crude oil purchases, which was unwound ratably during October 2021 to match monthly average pricing.
- A net short time spread position of 1.4 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through December 2022.
- A net crude oil basis spread position of 11.0 million barrels at multiple locations through December 2022. These derivatives allow us to lock in grade and location basis differentials.
- A net short position of 16.5 million barrels through December 2023 related to anticipated net sales of crude oil and NGL inventory.

Natural Gas Processing/NGL Fractionation — We purchase natural gas for processing and operational needs. Additionally, we purchase NGL mix for fractionation and sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. The following table summarizes our open derivative positions utilized to hedge the price risk associated with anticipated purchases and sales related to our natural gas processing and NGL fractionation activities as of September 30, 2021:

	Notional Volume (Short)/Long	Remaining Tenor
Natural gas purchases	67.4 Bcf	December 2023
Propane sales	(12.6) MMbls	December 2023
Butane sales	(1.9) MMbls	December 2023
Condensate sales (WTI position)	(2.5) MMbls	December 2023
Fuel gas requirements (1)	8.9 Bcf	December 2022
Power supply requirements (1)	0.7 TWh	December 2023

(1) Positions to hedge a portion of our power supply and fuel gas requirements at our Canadian natural gas processing and fractionation plants.

Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the normal purchases and normal sales scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings. We have determined that substantially all of our physical commodity contracts qualify for the normal purchases and normal sales scope exception.

Our commodity derivatives are not designated in a hedging relationship for accounting purposes; as such, changes in the fair value are reported in earnings. The following table summarizes the impact of our commodity derivatives recognized in earnings (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Supply and Logistics segment revenues	$ (206)	$ (37)	$ (804)	$ (22)
Field operating costs	17	5	73	5
Net gain/(loss) from commodity derivative activity	$ (189)	$ (32)	$ (731)	$ (17)

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. The following table provides the components of our net broker receivable/(payable) (in millions):

	September 30, 2021	December 31, 2020
Initial margin	$ 120	$ 91
Variation margin posted/(returned)	371	290
Letters of credit	(50)	(63)
Net broker receivable/(payable)	$ 441	$ 318

The following table reflects the Condensed Consolidated Balance Sheet line items that include the fair values of our commodity derivative assets and liabilities and the effect of the collateral netting. Such amounts are presented on a gross basis, before the effects of counterparty netting. However, we have elected to present our commodity derivative assets and liabilities with the same counterparty on a net basis on our Condensed Consolidated Balance Sheet when the legal right of offset exists. Amounts in the table below are presented in millions.

	September 30, 2021				December 31, 2020			
	Commodity Derivatives		Effect of Collateral Netting	Net Carrying Value Presented on the Balance Sheet	Commodity Derivatives		Effect of Collateral Netting	Net Carrying Value Presented on the Balance Sheet
	Assets	Liabilities			Assets	Liabilities		
Derivative Assets								
Other current assets	$ 196	$ (475)	$ 441	$ 162	$ 71	$ (314)	$ 318	$ 75
Other long-term assets, net	16	(2)	—	14	5	—	—	5
Derivative Liabilities								
Other current liabilities	5	(72)	—	(67)	9	(40)	—	(31)
Other long-term liabilities and deferred credits	1	(20)	—	(19)	—	(32)	—	(32)
Total	$ 218	$ (569)	$ 441	$ 90	$ 85	$ (386)	$ 318	$ 17

Interest Rate Risk Hedging

We use interest rate derivatives to hedge the benchmark interest rate associated with interest payments occurring as a result of debt issuances. The derivative instruments we use to manage this risk consist of forward starting interest rate swaps and treasury locks. These derivatives are designated as cash flow hedges. As such, changes in fair value are deferred in AOCI and are reclassified to interest expense as we incur the interest expense associated with the underlying debt.

The following table summarizes the terms of our outstanding interest rate derivatives as of September 30, 2021 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2023	1.38 %	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/14/2024	0.73 %	Cash flow hedge

As of September 30, 2021, there was a net loss of $194 million deferred in AOCI. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with interest expense accruals associated with underlying debt instruments. We estimate that substantially all of the remaining deferred loss will be reclassified to earnings through 2054 as the underlying hedged transactions impact earnings. A portion of these amounts is based on market prices as of September 30, 2021; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The following table summarizes the net unrealized gain/(loss) recognized in AOCI for derivatives (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Interest rate derivatives, net	$ 6	$ 22	$ 36	$ (39)

At September 30, 2021, the net fair value of our interest rate hedges, which were included in “Other long-term assets, net” on our Condensed Consolidated Balance Sheet, totaled $81 million. At December 31, 2020, the net fair value of these hedges totaled $46 million and was included in “Other long-term assets, net.”

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD, we use foreign currency derivatives to minimize the risk of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options.

Our use of foreign currency derivatives include (i) derivatives we use to hedge currency exchange risk created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales and (ii) foreign currency exchange contracts we use to manage our Canadian business cash requirements.

The following table summarizes our open forward exchange contracts as of September 30, 2021 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:	2021	$ 120	$ 153	$1.00 - $1.27

These derivatives are not designated in a hedging relationship for accounting purposes. As such, changes in fair value are recognized in earnings as a component of Supply and Logistics segment revenues. For the three months ended September 30, 2021 and 2020, the amounts recognized in earnings for our foreign currency derivatives were a loss of $3 million and a gain of $2 million, respectively. For the nine months ended September 30, 2021 and 2020, the amounts recognized in earnings for our foreign currency derivatives were a gain of less than $1 million and a loss of $2 million, respectively.

At September 30, 2021 and December 31, 2020, the net fair value of these foreign currency derivatives, which was included in “Other current assets” on our Condensed Consolidated Balance Sheets, totaled $1 million and $2 million, respectively.

Preferred Distribution Rate Reset Option

A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. 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 on our Condensed Consolidated Balance Sheets. This embedded derivative is not designated in a hedging relationship for accounting purposes and corresponding changes in fair value are recognized in “Other expense, net” in our Condensed Consolidated Statement of Operations. For the three months ended September 30, 2021 and 2020, we recognized a gain of $4 million and a loss of $10 million, respectively. For the nine months ended September 30, 2021 and 2020, we recognized net gains of $13 million and $7 million, respectively. The fair value of the Preferred Distribution Rate Reset Option, which was included in “Other long-term liabilities and deferred credits” on our Condensed Consolidated Balance Sheets, totaled $1 million and $14 million at September 30, 2021 and December 31, 2020, respectively. See Note 12 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for additional information regarding our Series A preferred units and the Preferred Distribution Rate Reset Option.

Recurring Fair Value Measurements

Derivative Financial Assets and Liabilities

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis (in millions):

	Fair Value as of September 30, 2021				Fair Value as of December 31, 2020			
Recurring Fair Value Measures [1]	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ (19)	$ (326)	$ (6)	$ (351)	$ (143)	$ (143)	$ (15)	$ (301)
Interest rate derivatives	—	81	—	81	—	46	—	46
Foreign currency derivatives	—	(1)	—	(1)	—	2	—	2
Preferred Distribution Rate Reset Option	—	—	(1)	(1)	—	—	(14)	(14)
Total net derivative asset/(liability)	$ (19)	$ (246)	$ (7)	$ (272)	$ (143)	$ (95)	$ (29)	$ (267)

(1) Derivative assets and liabilities are presented above on a net basis but do not include related cash margin deposits.

Level 1

Level 1 of the fair value hierarchy includes exchange-traded commodity derivatives and over-the-counter commodity contracts such as futures and swaps. The fair value of exchange-traded commodity derivatives and over-the-counter commodity contracts is based on unadjusted quoted prices in active markets.

Level 2

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity, interest rate and foreign currency derivatives that are traded in observable markets with less volume and transaction frequency than active markets. In addition, it includes certain physical commodity contracts. The fair values of these derivatives are corroborated with market observable inputs.

Level 3

Level 3 of the fair value hierarchy includes certain physical commodity and other contracts, over-the-counter options and the Preferred Distribution Rate Reset Option contained in our partnership agreement which is classified as an embedded derivative.

The fair values of our Level 3 physical commodity and other contracts and over-the-counter options are based on valuation models utilizing significant timing estimates, which involve management judgment, and pricing inputs from observable and unobservable markets with less volume and transaction frequency than active markets. Significant deviations from these estimates and inputs could result in a material change in fair value. We report unrealized gains and losses associated with these contracts in our Condensed Consolidated Statements of Operations as Supply and Logistics segment revenues.

The fair value of the embedded derivative feature contained in our partnership agreement is based on a valuation model that estimates the fair value of the Series A preferred units with and without the Preferred Distribution Rate Reset Option. This model contains inputs, including our common unit price, ten-year U.S. Treasury rates, default probabilities and timing estimates, some of which involve management judgment. A significant change in these inputs could result in a material change in fair value to this embedded derivative feature.

Rollforward of Level 3 Net Asset/(Liability)

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives classified as Level 3 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Beginning Balance	$ (13)	$ (42)	$ (29)	$ (51)
Net gains/(losses) for the period included in earnings	5	(9)	14	(1)
Settlements	1	4	8	5
Ending Balance	$ (7)	$ (47)	$ (7)	$ (47)
Change in unrealized losses included in earnings relating to Level 3 derivatives still held at the end of the period	$ 5	$ (9)	$ 14	$ (1)

Note 9—Related Party Transactions

See Note 17 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for a complete discussion of related parties, including the determination of our related parties and nature of involvement with such related parties.

On and effective as of August 19, 2021, the Board of Directors (the “Board”) of PAGP GP approved and adopted an amendment to PAGP GP’s limited liability company agreement (the “Amendment”) which eliminated all previously negotiated “director designation” rights and requires that all directors be subject to public election, including Kayne Anderson Capital Advisors, L.P.’s (“Kayne Anderson”) legacy contractual right to designate an individual to serve on the Board without being subject to public election. The Amendment also eliminated all previously negotiated rights, including Kayne Anderson’s right, to appoint a Board observer under certain circumstances. As a result of these changes, we no longer recognize Kayne Anderson and its affiliates as related parties.

During the three and nine months ended September 30, 2021 and 2020, we recognized sales and transportation revenues, purchased petroleum products and utilized transportation and storage services from our related parties. These transactions were conducted at posted tariff rates or prices that we believe approximate market.

The impact to our Condensed Consolidated Statements of Operations from these transactions is included below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Revenues from related parties [(1)]	$ 8	$ 7	$ 25	$ 40
Purchases and related costs from related parties [(1)]	$ 103	$ 116	$ 288	$ 339

(1) Crude oil purchases that are part of inventory exchanges under buy/sell transactions are netted with the related sales, with any margin presented in “Purchases and related costs” in our Condensed Consolidated Statements of Operations.

Our receivable and payable amounts with these related parties as reflected on our Condensed Consolidated Balance Sheets were as follows (in millions):

	September 30, 2021	December 31, 2020
Trade accounts receivable and other receivables, net from related parties [(1)]	$ 35	$ 34
Trade accounts payable to related parties [(1)] [(2)]	$ 71	$ 88

(1) Includes amounts related to crude oil purchases and sales, transportation and storage services and amounts owed to us or advanced to us related to investment capital projects of equity method investees where we serve as construction manager.

(2) We have agreements to store crude oil at facilities and transport crude oil or utilize capacity on pipelines that are owned by equity method investees. A portion of our commitment to transport is supported by crude oil buy/sell or other agreements with third parties with commensurate quantities.

Note 10—Commitments and Contingencies

Loss Contingencies — General

To the extent we are able to assess the likelihood of a negative outcome for a contingency, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue an undiscounted liability equal to the estimated amount. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then we accrue an undiscounted liability equal to the minimum amount in the range. In addition, we estimate legal fees that we expect to incur associated with loss contingencies and accrue those costs when they are material and probable of being incurred.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss.

Legal Proceedings — General

In the ordinary course of business, we are involved in various legal proceedings, including those arising from regulatory and environmental matters. In connection with determining the probability of loss associated with such legal proceedings and whether any potential losses associated therewith are estimable, we take into account what we believe to be all relevant known facts and circumstances, and what we believe to be reasonable assumptions regarding the application of those facts and circumstances to existing agreements, laws and regulations. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully protect us from losses arising from current or future legal proceedings.

Accordingly, we can provide no assurance that the outcome of the various legal proceedings that we are currently involved in, or will become involved with in the future, will not, individually or in the aggregate, have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Environmental — General

Although we have made significant investments in our maintenance and integrity programs, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail, storage and other facility operations. These releases can result from accidents or from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Damages and liabilities associated with any such releases from our existing or future assets could be significant and could have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and the amounts can be reasonably estimated. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We do not discount our environmental remediation liabilities to present value. We also record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. We record receivables for amounts we believe are recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

Environmental expenditures that pertain to current operations or to future revenues are expensed or capitalized consistent with our capitalization policy for property and equipment. Expenditures that result from the remediation of an existing condition caused by past operations and that do not contribute to current or future profitability are expensed.

At September 30, 2021, our estimated undiscounted reserve for environmental liabilities (excluding liabilities related to the Line 901 incident, as discussed further below) totaled $54 million, of which $9 million was classified as short-term and $45 million was classified as long-term. At December 31, 2020, our estimated undiscounted reserve for environmental liabilities (excluding liabilities related to the Line 901 incident) totaled $55 million, of which $8 million was classified as short-term and $47 million was classified as long-term. Such short-term liabilities are reflected in “Other current liabilities” and long-term liabilities are reflected in “Other long-term liabilities and deferred credits” on our Condensed Consolidated Balance Sheets. At September 30, 2021 and December 31, 2020, we had recorded receivables (excluding receivables related to the Line 901 incident) totaling $12 million and $6 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, $1 million of which for each period is reflected in “Other long-term assets, net” and the remainder is reflected in “Trade accounts receivable and other receivables, net” on our Condensed Consolidated Balance Sheets.

In some cases, the actual cash expenditures associated with these liabilities may not occur for three years or longer. Our estimates used in determining these reserves are based on information currently available to us 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 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 and the possibility of existing or future legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve is adequate, actual costs incurred (which may ultimately include costs for contingencies that are currently not reasonably estimable or costs for contingencies where the likelihood of loss is currently believed to be only reasonably possible or remote) may be in excess of the reserve and may potentially have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Specific Legal, Environmental or Regulatory Matters

Line 901 Incident. In May 2015, we experienced a crude oil release from our Las Flores to Gaviota Pipeline (Line 901) in Santa Barbara County, California. A portion of the released crude oil reached the Pacific Ocean at Refugio State Beach through a drainage culvert. Following the release, we shut down the pipeline and initiated our emergency response plan. A Unified Command, which included the United States Coast Guard, the EPA, the State of California Department of Fish and Wildlife (“CDFW”), the California Office of Spill Prevention and Response and the Santa Barbara Office of Emergency Management, was established for the response effort. Clean-up and remediation operations with respect to impacted shoreline and other areas has been determined by the Unified Command to be complete, and the Unified Command has been dissolved. Our estimate of the amount of oil spilled, based on relevant facts, data and information, and as set forth in the Consent Decree described below, is approximately 2,934 barrels; of this amount, we estimate that 598 barrels reached the Pacific Ocean.

As a result of the Line 901 incident, several governmental agencies and regulators initiated investigations into the Line 901 incident, various claims have been made against us and a number of lawsuits have been filed against us, the majority of which have been resolved. Set forth below is a brief summary of actions and matters that are currently pending or recently resolved:

As the “responsible party” for the Line 901 incident we are liable for various costs and for certain natural resource damages under the Oil Pollution Act. In this regard, following the Line 901 incident, we entered into a cooperative Natural Resource Damage Assessment (“NRDA”) process with the federal and state agencies designated or authorized by law to act as trustees for the natural resources of the United States and the State of California (collectively, the “Trustees”). Additionally, various government agencies sought to collect civil fines and penalties under applicable state and federal regulations. On March 13, 2020, the United States and the People of the State of California filed a civil complaint against Plains All American Pipeline, L.P. and Plains Pipeline L.P. along with a pre-negotiated settlement agreement in the form of a Consent Decree (the “Consent Decree”) that was signed by the United States Department of Justice, Environmental and Natural Resources Division, the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration, the EPA, CDFW, the California Department of Parks and Recreation, the California State Lands Commission, the California Department of Forestry and Fire Protection’s Office of the State Fire Marshal, Central Coast Regional Water Quality Control Board, and Regents of the University of California. The Consent Decree was approved and entered by the Federal District Court for the Central District of California on October 14, 2020. Pursuant to the terms of the Consent Decree, Plains paid $24 million in civil penalties and $22.325 million as compensation for injuries to, destruction of, loss of, or loss of use of natural resources resulting from the Line 901 incident. The Consent Decree also contains requirements for implementing certain agreed-upon injunctive relief, as well as requirements for potentially restarting Line 901 and the Sisquoc to Pentland portion of Line 903. The Consent Decree resolved all regulatory claims related to the incident.

Following an investigation and grand jury proceedings, in May of 2016, PAA was charged by a California state grand jury, pursuant to an indictment filed in California Superior Court, Santa Barbara County (the “May 2016 Indictment”), with alleged violations of California law in connection with the Line 901 incident. Fifteen charges from the May 2016 Indictment were the subject of a jury trial in California Superior Court in Santa Barbara County, and the jury returned a verdict on September 7, 2018, pursuant to which we were (i) found guilty on one felony discharge count and eight misdemeanor counts (which included one reporting count, one strict liability discharge count and six strict liability animal takings counts) and (ii) found not guilty on one strict liability animal takings count. The remaining counts were subsequently dismissed by the Court. On April 25, 2019, PAA was sentenced to pay fines and penalties in the aggregate amount of just under $3.35 million for the convictions covered by the September 2018 jury verdict (the “2019 Sentence”). The fines and penalties imposed in connection with the 2019 Sentence have been paid. The Superior Court recently concluded a series of hearings on the issue of whether there were any “direct victims” of the spill that are entitled to restitution under applicable criminal law. Through a series of final orders issued at the trial court level and without affecting any rights of the claimants under civil law, the Court dismissed the vast majority of the claims and ruled that the claimants were not entitled to restitution under applicable criminal laws. The Court did award an aggregate amount of less than $150,000 to a handful of claimants and we settled with approximately 40 claimants before the hearings for aggregate consideration that is not material. The prosecution has filed a Notice of Appeal indicating that it intends to appeal the Court’s rulings.

Shortly following the Line 901 incident, we established a claims line and encouraged any parties that were damaged by the release to contact us to discuss their damage claims. We received a number of claims through the claims line and we have processed those claims and made payments as appropriate. Nine class action lawsuits were filed against us; however, after various claims were either dismissed or consolidated, two proceedings remain pending in the United States District Court for the Central District of California. In the first proceeding, the plaintiffs claim two different classes of claimants were damaged by the release: (i) commercial fishermen who landed fish in certain specified fishing blocks in the waters off the coast of Southern California or persons or businesses who resold commercial seafood caught in those areas; and (ii) owners and lessees of residential beachfront properties, or properties with a private easement to a beach, where plaintiffs claim oil from the spill washed up. We are vigorously defending against those claims. A September 2020 trial date initially set by the Court has been postponed due to COVID-19 related trial suspensions. In the second proceeding, the plaintiffs seek a declaratory judgment that Plains’ right-of-way agreements would not allow Plains to lay a new pipeline to replace Line 901 and/or the non-operating segment of Line 903 without paying additional compensation. No trial date has been set in that action.

In addition, four unitholder derivative lawsuits were filed by certain purported investors in the Partnership against PAGP and certain of the Partnership’s affiliates, officers and directors. After various claims were either dismissed or consolidated, one proceeding against PAGP remains pending in Delaware Chancery Court. Generally, the plaintiffs claim that PAGP failed to exercise proper oversight over the Partnership’s pipeline integrity efforts. We will continue to vigorously defend against the claim. No trial date has been set in this action.

We have also received several other individual lawsuits and claims from companies, governmental agencies and individuals alleging damages arising out of the Line 901 incident. These lawsuits and claims generally seek restitution, compensatory and punitive damages, and/or injunctive relief. The majority of these lawsuits have been settled or dismissed by the court. Remaining claims include claims for lost revenue or profit asserted by a former oil producer that declared bankruptcy and shut in its offshore production platform following the Line 901 incident, a state agency that received royalties on oil produced from that platform until it was abandoned by its owner, and various companies and individuals who provided labor, goods, or services associated with oil production activities they claim were disrupted following the Line 901 incident. We are vigorously defending these suits. We may be subject to additional claims and lawsuits, which could materially impact the liabilities and costs we currently expect to incur as a result of the Line 901 incident.

Taking the foregoing into account, as of September 30, 2021, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $485 million, which includes actual and projected emergency response and clean-up costs, natural resource damage assessments, fines and penalties payable pursuant to the Consent Decree and certain third party claims settlements, as well as estimates for certain legal fees. We accrue such estimates of aggregate total costs to “Field operating costs” in our Condensed Consolidated Statements of Operations. This estimate considers our prior experience in environmental investigation and remediation matters and available data from, and in consultation with, our environmental and other specialists, as well as currently available facts and presently enacted laws and regulations. We have made assumptions for (i) the resolution of certain third party claims and lawsuits, but excluding claims and lawsuits with respect to which losses are not probable and reasonably estimable, and excluding future claims and lawsuits and (ii) the nature, extent and cost of legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Line 901 incident. Our estimate does not include any lost revenue associated with the shutdown of Line 901 or 903 and does not include any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where we currently regard the likelihood of loss as being only reasonably possible or remote. We believe we have accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that we have made. For example, with respect to potential losses that we regard as only reasonably possible or remote, we have made assumptions regarding the strength of our legal position based on our assessment of the relevant facts and applicable law and precedent; if our assumptions regarding such matters turn out to be inaccurate (i.e., we are found to be liable under circumstances where we regard the likelihood of loss as being only reasonably possible or remote), we could be responsible for significant costs and expenses that are not currently included in our estimates and accruals. In addition, for any potential losses that we regard as probable and for which we have accrued an estimate of the potential losses, our estimates regarding damages, legal fees, court costs and interest could turn out to be inaccurate and the actual losses we incur could be significantly higher than the amounts included in our estimates and accruals. Also, the amount of time it takes for us to resolve all of the current and future lawsuits and claims that relate to the Line 901 incident could turn out to be significantly longer than we have assumed, and as a result the costs we incur for legal services could be significantly higher than we have estimated. Accordingly, our assumptions and estimates may turn out to be inaccurate and our total costs could turn out to be materially higher; therefore, we can provide no assurance that we will not have to accrue significant additional costs in the future with respect to the Line 901 incident.

As of September 30, 2021, we had a remaining undiscounted gross liability of $103 million related to this event, which is reflected in “Trade accounts payable” and “Other current liabilities” on our Condensed Consolidated Balance Sheet. We maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such environmental liabilities. Subject to such exclusions and deductibles, we believe that our coverage is adequate to cover the current estimated total emergency response and clean-up costs, claims settlement costs and remediation costs and we believe that this coverage is also adequate to cover any potential increase in the estimates for these costs that exceed the amounts currently identified. Through September 30, 2021, we had collected, subject to customary reservations, $250 million out of the approximate $360 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of September 30, 2021, we have recognized a receivable of approximately $110 million for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles and amounts already collected. Such amount is recognized as a current asset in “Trade accounts receivable and other receivables, net” on our Condensed Consolidated Balance Sheet. We have completed the required clean-up and remediation work as determined by the Unified Command and the Unified Command has been dissolved; however, we expect to make payments for additional costs associated with restoration of the impacted areas, as well as legal, professional and regulatory costs during future periods.

Note 11—Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 3 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for a summary of the types of products and services from which each segment derives its revenues. Our CODM (our Chief Executive Officer) evaluates segment performance based on measures including Segment Adjusted EBITDA (as defined below) and maintenance capital investment.

We define Segment Adjusted EBITDA as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses, plus our proportionate share of the depreciation and amortization expense of unconsolidated entities, and further adjusted for certain selected items including (i) 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, (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 the applicable amounts subsequently recognized into revenue and (v) other items that our CODM believes are integral to understanding our core segment operating performance. Segment Adjusted EBITDA excludes depreciation and amortization.

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 following tables reflect certain financial data for each segment (in millions):

	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Three Months Ended September 30, 2021					
Revenues:					
External customers [1]	$ 222	$ 128	$ 10,515	$ (89)	$ 10,776
Intersegment [2]	307	98	—	89	494
Total revenues of reportable segments	$ 529	$ 226	$ 10,515	$ —	$ 11,270
Equity earnings in unconsolidated entities	$ 67	$ 2	$ —		$ 69
Segment Adjusted EBITDA	$ 427	$ 114	$ (23)		$ 518
Maintenance capital	$ 22	$ 18	$ 3		$ 43
Three Months Ended September 30, 2020					
Revenues:					
External customers [1]	$ 242	$ 150	$ 5,537	$ (96)	$ 5,833
Intersegment [2]	252	121	—	96	469
Total revenues of reportable segments	$ 494	$ 271	$ 5,537	$ —	$ 6,302
Equity earnings in unconsolidated entities	$ 87	$ 2	$ —		$ 89
Segment Adjusted EBITDA	$ 444	$ 176	$ 61		$ 681
Maintenance capital	$ 34	$ 10	$ 9		$ 53
Nine Months Ended September 30, 2021					
Revenues:					
External customers [1]	$ 700	$ 436	$ 28,221	$ (268)	$ 29,089
Intersegment [2]	868	305	1	268	1,442
Total revenues of reportable segments	$ 1,568	$ 741	$ 28,222	$ —	$ 30,531
Equity earnings in unconsolidated entities	$ 185	$ 5	$ —		$ 190
Segment Adjusted EBITDA	$ 1,248	$ 425	$ (31)		$ 1,642
Maintenance capital	$ 68	$ 39	$ 9		$ 116
Nine Months Ended September 30, 2020					
Revenues:					
External customers [1]	$ 774	$ 473	$ 16,370	$ (290)	$ 17,327
Intersegment [2]	756	387	1	290	1,434
Total revenues of reportable segments	$ 1,530	$ 860	$ 16,371	$ —	$ 18,761
Equity earnings in unconsolidated entities	$ 276	$ 4	$ —		$ 280
Segment Adjusted EBITDA	$ 1,233	$ 560	$ 205		$ 1,998
Maintenance capital	$ 98	$ 40	$ 19		$ 157

(1) Transportation revenues from External customers include tariff revenue from transporting volumes associated with certain inventory exchanges with our customers where our Supply and Logistics segment has transacted the inventory exchange and serves as the shipper on our pipeline systems. See Note 3 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for a discussion of our related accounting policy. We have included an estimate of the revenues from these inventory exchanges in our Transportation segment revenues from External customers presented above and adjusted those revenues out such that Total revenues from External customers reconciles to our Condensed Consolidated Statements of Operations. This presentation is consistent with the information provided to our CODM.

(2) Segment revenues include intersegment amounts that are eliminated in Purchases and related costs and Field operating costs in our Condensed Consolidated Statements of Operations. Intersegment activities are conducted at posted tariff rates where applicable, or otherwise at rates similar to those charged to third parties or rates that we believe approximate market at the time the agreement is executed or renegotiated.

Segment Adjusted EBITDA Reconciliation

The following table reconciles Segment Adjusted EBITDA to Net income/(loss) attributable to PAA (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Segment Adjusted EBITDA	$ 518	$ 681	$ 1,642	$ 1,998
Adjustments: [1]				
Depreciation and amortization of unconsolidated entities [2]	(21)	(18)	(109)	(51)
Gains/(losses) from derivative activities and inventory valuation adjustments [3]	(13)	(88)	23	(210)
Long-term inventory costing adjustments [4]	13	(2)	81	(66)
Deficiencies under minimum volume commitments, net [5]	(56)	(64)	(31)	(69)
Equity-indexed compensation expense [6]	(6)	(5)	(14)	(13)
Net gain/(loss) on foreign currency revaluation [7]	(3)	(4)	(2)	9
Significant transaction-related expenses [8]	(2)	—	(5)	(3)
Depreciation and amortization	(178)	(160)	(551)	(493)
Gains/(losses) on asset sales and asset impairments, net	(221)	2	(592)	(617)
Goodwill impairment losses	—	—	—	(2,515)
Gain on/(impairment of) investments in unconsolidated entities, net	—	(91)	—	(182)
Interest expense, net	(106)	(113)	(319)	(329)
Other income/(expense), net	(10)	5	13	(7)
Income/(loss) before tax	(85)	143	136	(2,548)
Income tax (expense)/benefit	30	3	16	(7)
Net income/(loss)	(55)	146	152	(2,555)
Net income attributable to noncontrolling interests	(4)	(3)	(9)	(7)
Net income/(loss) attributable to PAA	$ (59)	$ 143	$ 143	$ (2,562)

(1) Represents adjustments utilized by our CODM in the evaluation of segment results.

(2) Includes our proportionate share of the depreciation and amortization expense (including write-downs related to cancelled projects) of unconsolidated entities.

(3) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results, we identify differences in the timing of earnings from the derivative instruments and the underlying transactions and exclude the related gains and losses in determining Segment Adjusted EBITDA such that the earnings from the derivative instruments and the underlying transactions impact Segment Adjusted EBITDA in the same period. In addition, we exclude gains and losses on derivatives that are related to investing activities, such as the purchase of linefill.

(4) We carry crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We exclude the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and write-downs of such inventory that result from price declines from Segment Adjusted EBITDA.

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

(6) Our total equity-indexed compensation expense includes expense associated with awards that will be settled in units and awards that will be settled in cash. The awards that will be settled in units are included in our diluted net income per unit calculation when the applicable performance criteria have been met. We exclude compensation expense associated with these awards in determining Segment Adjusted EBITDA as the dilutive impact of the outstanding awards is included in our diluted net income per unit calculation, as applicable. The portion of compensation expense associated with awards that will settle in cash is not excluded in determining Segment Adjusted EBITDA. See Note 18 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for a discussion regarding our equity-indexed compensation plans.

(7) 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. These gains and losses are not integral to our core operating performance and were therefore excluded in determining Segment Adjusted EBITDA. See Note 8 for discussion regarding our currency exchange rate risk hedging activities.

(8) Includes expenses associated with the Plains Oryx Permian Basin joint venture transaction, which closed on October 5, 2021, and the acquisition of Felix Midstream LLC in 2020. See Note 12 for further discussion of the joint venture transaction and Note 7 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for additional discussion of the Felix Midstream LLC acquisition.

Note 12—Acquisitions, Divestitures and Other Transactions

Asset Exchange

In June 2021, we closed on an asset exchange agreement (the "Asset Exchange") with Inter Pipeline Ltd., through which we acquired additional interests in two straddle plants included in our Facilities segment that we currently operate, in exchange for a pipeline and related storage and truck offload facilities previously included in our Transportation segment and cash consideration of $32 million, including working capital and other adjustments. We recognized a gain of $106 million on the divestiture of the pipeline and related storage and truck offload facilities, which is included in "(Gains)/losses on asset sales and asset impairments, net" on our Condensed Consolidated Statement of Operations, based on the difference between the fair value of the divested assets and their carrying value.

Divestitures

In August 2021, we sold our Pine Prairie and Southern Pines natural gas storage facilities, previously included in our Facilities segment, for net proceeds of approximately $850 million, including working capital adjustments. As of June 30, 2021, we classified the assets related to this transaction (primarily "Property and equipment"), valued at the lower of the carrying amount or fair value less costs to sell, of approximately $832 million as assets held for sale with approximately $18 million of deferred losses on hedges remaining in other comprehensive income until the closing of the sale. Upon classification of the assets to held for sale in the second quarter of 2021, we recognized a non-cash impairment loss of approximately $475 million which is included in "(Gains)/losses on asset sales and asset impairments, net" on our Condensed Consolidated Statement of Operations.

Joint Venture Transaction

On October 5, 2021, we and Oryx Midstream Holdings LLC ("Oryx Midstream") completed the merger, in a cashless, debt-free transaction, of our respective Permian Basin assets, operations and commercial activities into a newly formed joint venture, Plains Oryx Permian Basin LLC ("Plains Oryx Permian Basin"). Plains Oryx Permian Basin includes all of Oryx Midstream's Permian Basin assets and, with the exception of our long-haul pipeline systems and certain of our intra-basin terminal assets, the vast majority of our assets located within the Permian Basin. We own 65% of Plains Oryx Permian Basin, operate the combined assets and will reflect Plains Oryx Permian Basin as a consolidated subsidiary in our consolidated financial statements. The initial accounting for this transaction was not complete as of the financial statement issuance date.

Oryx Midstream is a portfolio company of Stonepeak Infrastructure Partners ("Stonepeak"). Affiliates of Stonepeak own approximately 8.9% of our outstanding Series A Preferred Units, which equates to less than 1% of our outstanding common units and common unit equivalents combined.

Asset Impairments (Held and Used)

During the nine months ended September 30, 2021, we recognized approximately $220 million of non-cash impairment losses related to certain crude oil storage terminal assets included in our Facilities segment. This amount is reflected in "(Gains)/losses on asset sales and asset impairments, net" on our Condensed Consolidated Statements of Operations.

Decreased demand for our services related to changing market conditions resulted in decreases in expected future cash flows for certain of our assets, which was a triggering event that required us to assess the recoverability of our carrying value of such long-lived assets. As a result of our impairment review, we wrote off the portion of the carrying amount of these long-lived assets that exceeded their fair value. Our estimated fair value (which we consider a Level 3 measurement in the fair value hierarchy) was primarily based upon an assumption for the amount for which the relevant assets and land could be sold.

Item 2. 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 and Management's Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2020 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the Condensed Consolidated Financial Statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Our discussion and analysis includes the following:

- Executive Summary
- Results of Operations
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Forward-Looking Statements

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. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics.

Recent Developments

On August 2, 2021, we completed the sale of our Pine Prairie and Southern Pines natural gas storage facilities for net proceeds of approximately $850 million, including working capital adjustments. In connection with the sale, we repaid term loans totaling $200 million.

On October 5, 2021, we and Oryx Midstream completed the merger of our respective Permian Basin assets, operations and commercial activities into a newly formed strategic joint venture, Plains Oryx Permian Basin. Plains Oryx Permian Basin includes all of Oryx Midstream's Permian Basin assets and, with the exception of our long-haul pipeline systems and certain of our intra-basin terminal assets, the vast majority of our assets located within the Permian Basin. We own 65% of Plains Oryx Permian Basin, operate the combined assets and will reflect Plains Oryx Permian Basin as a consolidated subsidiary in our consolidated financial statements. Structured as a debt-free joint venture entity through a cashless transaction, this aligns with our financial and portfolio optimization strategies and is expected to be near-term free cash flow accretive.

Overview of Operating Results

During the first nine months of 2021, we recognized net income of $152 million compared to a net loss of $2.555 billion recognized during the first nine months of 2020. The net loss for the 2020 period was primarily driven by 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 $3.33 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 comparable nine-month 2021 period includes a net loss on asset sales and asset impairments of $592 million.

Results from our reporting segments during the first nine months of 2021 decreased from the comparable 2020 period driven primarily by the impact of less favorable crude oil market conditions combined with lower realized NGL margins in our Supply and Logistics segment. In addition, our Facilities segment was unfavorably impacted by reduced NGL capacity utilization and market rates as well as the impact of asset sales. These unfavorable results were partially offset by favorable Transportation segment results that benefited from the collection of deficiency payments associated with minimum volume commitments and lower operating costs.

See further discussion of our operating results in the "—Results of Operations—Analysis of Operating Segments" and "—Other Income and Expenses" sections below.

Results of Operations

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

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Variance $	Variance %	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	Variance $	Variance %
Transportation Segment Adjusted EBITDA [1]	$ 427	$ 444	$ (17)	(4)%	$ 1,248	$ 1,233	$ 15	1 %
Facilities Segment Adjusted EBITDA [1]	114	176	(62)	(35)%	425	560	(135)	(24)%
Supply and Logistics Segment Adjusted EBITDA [1]	(23)	61	(84)	(138)%	(31)	205	(236)	(115)%
Adjustments:								
Depreciation and amortization of unconsolidated entities	(21)	(18)	(3)	(17)%	(109)	(51)	(58)	(114)%
Selected items impacting comparability - Segment Adjusted EBITDA	(67)	(163)	96	**	52	(352)	404	**
Depreciation and amortization	(178)	(160)	(18)	(11)%	(551)	(493)	(58)	(12)%
Gains/(losses) on asset sales and asset impairments, net	(221)	2	(223)	**	(592)	(617)	25	4 %
Goodwill impairment losses	—	—	—	N/A	—	(2,515)	2,515	100 %
Gain on/(impairment of) investments in unconsolidated entities, net	—	(91)	91	100 %	—	(182)	182	100 %
Interest expense, net	(106)	(113)	7	6 %	(319)	(329)	10	3 %
Other income/(expense), net	(10)	5	(15)	**	13	(7)	20	**
Income tax (expense)/benefit	30	3	27	**	16	(7)	23	**
Net income/(loss)	(55)	146	(201)	(138)%	152	(2,555)	2,707	106 %
Net income attributable to noncontrolling interests	(4)	(3)	(1)	(33)%	(9)	(7)	(2)	(29)%
Net income/(loss) attributable to PAA	$ (59)	$ 143	$ (202)	(141)%	$ 143	$ (2,562)	$ 2,705	106 %
Basic and diluted net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.28)	**	$ (0.01)	$ (3.72)	$ 3.71	**
Basic and diluted weighted average common units outstanding	715	728	(13)	**	719	728	(9)	**

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

(1) Segment Adjusted EBITDA is the measure of segment performance that is utilized by our CODM to assess performance and allocate resources among our operating segments. This measure is adjusted for certain items, including those that our CODM believes impact comparability of results across periods. See Note 11 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

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"), 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 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 Condensed 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 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 Condensed 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."

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The following tables set forth the reconciliation of the non-GAAP financial performance measures Adjusted EBITDA and Implied DCF from Net Income/(Loss) (in millions):

	Three Months Ended September 30,		Variance		Nine Months Ended September 30,		Variance	
	2021	2020	$	%	2021	2020	$	%
Net income/(loss)	$ (55)	$ 146	$ (201)	(138)%	$ 152	$ (2,555)	$ 2,707	106 %
Interest expense, net	106	113	(7)	(6)%	319	329	(10)	(3)%
Income tax expense/(benefit)	(30)	(3)	(27)	**	(16)	7	(23)	**
Depreciation and amortization	178	160	18	11 %	551	493	58	12 %
(Gains)/losses on asset sales and asset impairments, net	221	(2)	223	**	592	617	(25)	(4)%
Goodwill impairment losses	—	—	—	N/A	—	2,515	(2,515)	(100)%
(Gain on)/impairment of investments in unconsolidated entities, net	—	91	(91)	(100)%	—	182	(182)	(100)%
Depreciation and amortization of unconsolidated entities [1]	21	18	3	17 %	109	51	58	114 %
Selected Items Impacting Comparability:								
(Gains)/losses from derivative activities and inventory valuation adjustments	13	88	(75)	**	(23)	210	(233)	**
Long-term inventory costing adjustments	(13)	2	(15)	**	(81)	66	(147)	**
Deficiencies under minimum volume commitments, net	56	64	(8)	**	31	69	(38)	**
Equity-indexed compensation expense	6	5	1	**	14	13	1	**
Net (gain)/loss on foreign currency revaluation	3	4	(1)	**	2	(9)	11	**
Significant transaction-related expenses	2	—	2	**	5	3	2	**
Selected Items Impacting Comparability - Segment Adjusted EBITDA [2]	67	163	(96)	**	(52)	352	(404)	**
(Gains)/losses from derivative activities [3]	(4)	10	(14)	**	(13)	(7)	(6)	**
Net (gain)/loss on foreign currency revaluation [4]	15	(14)	29	**	1	20	(19)	**
Net gain on early repayment of senior notes [5]	—	—	—	**	—	(3)	3	**
Selected Items Impacting Comparability - Adjusted EBITDA [6]	78	159	(81)	**	(64)	362	(426)	**
Adjusted EBITDA [6]	$ 519	$ 682	$ (163)	(24)%	$ 1,643	$ 2,001	$ (358)	(18)%
Interest expense, net of certain non-cash items [7]	(99)	(107)	8	7 %	(301)	(313)	12	4 %
Maintenance capital [8]	(43)	(53)	10	19 %	(116)	(157)	41	26 %
Current income tax expense	(8)	(17)	9	53 %	(11)	(39)	28	72 %
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [9]	9	(1)	10	**	11	7	4	**
Distributions to noncontrolling interests [10]	(4)	(2)	(2)	(100)%	(10)	(6)	(4)	(67)%
Implied DCF	$ 374	$ 502	$ (128)	(25)%	$ 1,216	$ 1,493	$ (277)	(19)%
Preferred unit distributions [10]	(37)	(37)	—	— %	(137)	(137)	—	— %
Implied DCF Available to Common Unitholders	$ 337	$ 465	$ (128)	(28)%	$ 1,079	$ 1,356	$ (277)	(20)%
Common unit cash distributions [10]	(129)	(131)			(389)	(524)		
Implied DCF Excess [11]	$ 208	$ 334			$ 690	$ 832		

** 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 such 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 11 to our Condensed 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 Condensed 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 8 to our Condensed 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 were thus 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.

(6) Other income/(expense), net per our Condensed 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) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

(8) 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.

(9) 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).

(10) Cash distributions paid during the period presented.

(11) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes.

Analysis of Operating Segments

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

We define Segment Adjusted EBITDA as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses, plus our proportionate share of the depreciation and amortization expense (including write-downs related to cancelled projects) of unconsolidated entities, and further adjusted for certain selected items including (i) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (ii) long-term inventory costing adjustments, (iii) charges for obligations that are expected to be settled with the issuance of equity instruments, (iv) amounts related to deficiencies associated with minimum volume commitments, net of applicable amounts subsequently recognized into revenue and (v) other items that our CODM believes are integral to understanding our core segment operating performance. See Note 11 to our Condensed Consolidated Financial Statements for a reconciliation of Segment Adjusted EBITDA to Net income/(loss) attributable to PAA.

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

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems and trucks. The Transportation segment generates revenue through a combination of tariffs, pipeline capacity agreements and other transportation fees. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment results generated by our tariff and other fee-related activities depend on the volumes transported on the pipeline and the level of the tariff and other fees charged, as well as the fixed and variable field costs of operating the pipeline.

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

Operating Results [1] (in millions, except per barrel data)	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Variance $	Variance %	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	Variance $	Variance %
Revenues	$ 529	$ 494	$ 35	7 %	$ 1,568	$ 1,530	$ 38	2 %
Purchases and related costs	(75)	(60)	(15)	(25)%	(181)	(184)	3	2 %
Field operating costs	(149)	(139)	(10)	(7)%	(394)	(440)	46	10 %
Segment general and administrative expenses [2]	(25)	(22)	(3)	(14)%	(79)	(73)	(6)	(8)%
Equity earnings in unconsolidated entities	67	87	(20)	(23)%	185	276	(91)	(33)%
Adjustments: [3]								
Depreciation and amortization of unconsolidated entities	20	17	3	18 %	107	49	58	118 %
Losses from derivative activities and inventory valuation adjustments	—	—	—	**	(1)	—	(1)	**
Deficiencies under minimum volume commitments, net	56	64	(8)	**	33	64	(31)	**
Equity-indexed compensation expense	3	3	—	**	8	8	—	**
Significant transaction-related expenses	1	—	1	**	2	3	(1)	**
Segment Adjusted EBITDA	$ 427	$ 444	$ (17)	(4)%	$ 1,248	$ 1,233	$ 15	1 %
Maintenance capital	$ 22	$ 34	$ (12)	(35)%	$ 68	$ 98	$ (30)	(31)%
Segment Adjusted EBITDA per barrel	$ 0.73	$ 0.79	$ (0.06)	(8)%	$ 0.75	$ 0.70	$ 0.05	7 %

Average Daily Volumes (in thousands of barrels per day) [4]	**Three Months Ended September 30,**		**Variance**		**Nine Months Ended September 30,**		**Variance**	
	2021	**2020**	**Volumes**	**%**	**2021**	**2020**	**Volumes**	**%**
Tariff activities volumes								
Crude oil pipelines (by region):								
Permian Basin [5]	4,394	4,200	194	5 %	4,114	4,507	(393)	(9)%
South Texas / Eagle Ford [5]	311	370	(59)	(16)%	315	383	(68)	(18)%
Central [5]	483	388	95	24 %	441	383	58	15 %
Gulf Coast	176	137	39	28 %	161	133	28	21 %
Rocky Mountain [5]	344	238	106	45 %	320	251	69	27 %
Western	224	232	(8)	(3)%	239	217	22	10 %
Canada	230	303	(73)	(24)%	279	291	(12)	(4)%
Crude oil pipelines	6,162	5,868	294	5 %	5,869	6,165	(296)	(5)%
NGL pipelines	165	180	(15)	(8)%	176	187	(11)	(6)%
Tariff activities total volumes	6,327	6,048	279	5 %	6,045	6,352	(307)	(5)%
Trucking volumes	58	67	(9)	(13)%	62	75	(13)	(17)%
Transportation segment total volumes	6,385	6,115	270	4 %	6,107	6,427	(320)	(5)%

** 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 11 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

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

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

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

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

	Favorable/(Unfavorable) Variance Three Months Ended September 30, 2021-2020			Favorable/(Unfavorable) Variance Nine Months Ended September 30, 2021-2020		
(in millions)	Revenues	Purchases and Related Costs	Equity Earnings	Revenues	Purchases and Related Costs	Equity Earnings
Permian Basin region	$ 14	$ (14)	$ (16)	$ 21	$ (7)	$ (34)
South Texas / Eagle Ford region	(3)	—	(2)	(10)	—	(14)
Central region	5	—	1	8	1	(23)
Gulf Coast region	3	—	—	5	—	(10)
Rocky Mountain region	9	—	(3)	21	—	(10)
Other regions, NGL pipelines, trucking and pipeline loss allowance revenue	7	(1)	—	(7)	9	—
Total variance	$ 35	$ (15)	$ (20)	$ 38	$ 3	$ (91)

- *Permian Basin region.* Revenues, net of purchases and related costs, ("net revenues") increased by $14 million for the nine months ended September 30, 2021, compared to the same period in 2020 primarily due to the recognition of revenue associated with minimum volume commitments in the first and second quarters of 2021. Such favorable impacts were partially offset by lower volumes of crude oil produced in the Permian Basin in the first quarter of 2021, driven by the COVID-19 pandemic-related reset to production and compounded by shut-ins from the extreme winter weather event that occurred in February of 2021 ("Winter Storm Uri").

  Equity earnings decreased for the three and nine months ended September 30, 2021 compared to the same periods in 2020 primarily due to 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, long-haul volumes shipped at lower rates and our proportionate share of the write-off of costs associated with a capital project canceled during the second quarter of 2021, partially offset by lower power costs related to Winter Storm Uri.

- *South Texas / Eagle Ford region.* Revenues and volumes decreased for the three and nine months ended September 30, 2021 compared to the same periods in 2020 due to lower production, including, for the nine-month period, the impact of curtailments from Winter Storm Uri in the first quarter of 2021.

  Equity earnings decreased for the nine months ended September 30, 2021 compared to the same period in 2020 due to a combination of lower joint tariff volumes from our Permian Basin long-haul system, and to a lesser extent, lower regional receipts, partially offset by the recognition of previously deferred revenue associated with minimum volume commitments.

- *Central region.* Revenues increased for the three and nine months ended September 30, 2021 compared to the same periods in 2020 primarily due to higher volumes on certain of our pipelines in the region, including the Red River pipeline, as a result of (i) additional volume commitments beginning in the third quarter of 2020 and the second quarter of 2021 and (ii) an expansion placed into service in October 2020.

  Equity earnings decreased for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to our proportionate share of Diamond Pipeline's write-off of costs associated with the cancellation of the project to connect Diamond Pipeline to Capline Pipeline (the Byhalia Connection) during the second quarter of 2021.

- *Gulf Coast region.* Revenues increased slightly for the three and nine months ended September 30, 2021 compared to the same periods in 2020 due to higher movements on a low tariff pipeline.

  Equity earnings decreased for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to our proportionate share of Capline Pipeline's write-off of costs associated with the cancellation of the project to connect Diamond Pipeline to Capline Pipeline (the Byhalia Connection) during the second quarter of 2021.

- *Rocky Mountain region.* Revenues increased for the three and nine months ended September 30, 2021 compared to the same periods in 2020 primarily due to (i) increased movements on our cross-border pipelines and (ii) a new joint tariff movement to Cushing, Oklahoma.

  Equity earnings decreased for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to the expiration of higher-tariff volume commitments in the current period on the White Cliffs pipeline, partially offset by higher volumes from committed shippers on the Saddlehorn pipeline.

Adjustments: Deficiencies under minimum volume commitments, net. Many industry infrastructure projects developed and completed over the last several years were underpinned by long-term minimum volume commitment contracts whereby the shipper 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.

For each of the three and nine month periods ended September 30, 2021 and 2020, we billed and deferred amounts from counterparties associated with deficiencies under minimum volume commitments. In each of the periods presented, the amount we billed was in excess of the amount we recognized into revenue.

Field Operating Costs. The decrease in field operating costs for the nine months ended September 30, 2021 compared to the same period in 2020 was primarily due to (i) lower power costs, including the impact of gains related to hedged power costs resulting from Winter Storm Uri and (ii) streamlining efforts which have resulted in decreases in variable costs and maintenance and chemicals and additives costs. These favorable impacts were partially offset by increased field operating costs for the three months ended September 30, 2021 compared to the three months ended September 30, 2020 due to (i) higher compensation costs, including lower wage subsidies received by our Canadian subsidiary, and (ii) an increase in power costs due to higher volumes.

Segment General and Administrative Expenses. The increase in segment general and administrative expenses for the three and nine months ended September 30, 2021 compared to the same periods in 2020 was primarily due to increased information systems costs and reduced wage subsidies received by our Canadian subsidiary in the current periods. The nine-month comparative period was further unfavorably impacted by an increase in equity-indexed compensation expense on liability-classified awards (which are not included as an "Adjustment" in the table above) due to an increase in our common unit price.

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 spending for the three and nine months ended September 30, 2021 compared to the same periods in 2020 was primarily due to timing changes, the completion of multi-year reliability improvement programs and application of updated regulatory guidance, among other factors.

Facilities Segment

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

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

Operating Results [1] (in millions, except per barrel data)	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Variance $	Variance %	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	Variance $	Variance %
Revenues	$ 226	$ 271	$ (45)	(17)%	$ 741	$ 860	$ (119)	(14)%
Purchases and related costs	(1)	(2)	1	50 %	(7)	(12)	5	42 %
Field operating costs	(86)	(73)	(13)	(18)%	(238)	(233)	(5)	(2)%
Segment general and administrative expenses [2]	(20)	(18)	(2)	(11)%	(60)	(63)	3	5 %
Equity earnings in unconsolidated entities	2	2	—	— %	5	4	1	25 %
Adjustments: [3]								
Depreciation and amortization of unconsolidated entities	1	1	—	**	2	2	—	**
(Gains)/losses from derivative activities	(9)	(6)	(3)	**	(19)	(5)	(14)	**
Deficiencies under minimum volume commitments, net	—	—	—	**	(2)	5	(7)	**
Equity-indexed compensation expense	1	1	—	**	3	2	1	**
Segment Adjusted EBITDA	$ 114	$ 176	$ (62)	(35)%	$ 425	$ 560	$ (135)	(24)%
Maintenance capital	$ 18	$ 10	$ 8	80 %	$ 39	$ 40	$ (1)	(3)%
Segment Adjusted EBITDA per barrel	$ 0.35	$ 0.47	$ (0.12)	(26)%	$ 0.42	$ 0.50	$ (0.08)	(16)%

Volumes [4]	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Variance Volumes	Variance %	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	Variance Volumes	Variance %
Liquids storage (average monthly capacity in millions of barrels) [5]	100	111	(11)	(10)%	100	110	(10)	(9)%
Natural gas storage (average monthly working capacity in billions of cubic feet)	23	67	(44)	(66)%	54	66	(12)	(18)%
NGL fractionation (average volumes in thousands of barrels per day)	119	110	9	8 %	130	129	1	1 %
Facilities segment total volumes (average monthly volumes in millions of barrels) [6]	108	125	(17)	(14)%	113	125	(12)	(10)%

** 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 11 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

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

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

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

The following is a discussion of items impacting Facilities segment operating results.

Revenues, Purchases and Related Costs and Volumes. Variances in net revenues and average monthly volumes were primarily driven by the following:

- *NGL Operations.* Revenues from our NGL operations decreased by $13 million and $70 million for the three and nine months ended September 30, 2021, respectively, compared to the same periods in 2020 primarily due to reduced intersegment facility fees to reflect lower utilization and market rates at certain of our NGL facilities (which had an offsetting favorable impact on our Supply and Logistics segment). The nine-month comparative period was further unfavorably impacted by (i) a benefit in the 2020 comparative period from the receipt of a deficiency payment of approximately $20 million upon the expiration of a multi-year contract and (ii) the sale of certain NGL terminals in the second quarter of 2020. Such unfavorable impacts were partially offset for the three- and nine-month comparative periods by more favorable foreign exchange impacts in 2021 of approximately $6 million and $25 million, respectively, and, for the nine-month comparative period, gains at certain of our fractionation facilities in the first quarter of 2021.

- *Crude Oil Operations.* Revenues from our crude oil storage operations decreased by $8 million and $39 million for the three and nine months ended September 30, 2021, respectively, compared to the same periods in 2020 primarily due to the sale of our Los Angeles Basin terminals in October of 2020, partially offset by increased capacity and activity at certain of our Mid-Continent area terminals. In addition, revenues from our crude oil rail operations decreased by $4 million and $11 million for the three and nine months ended September 30, 2021, respectively, compared to the same periods in 2020 due to decreased movements and expiration of contracts.

- *Natural Gas Storage.* Net revenues decreased by $18 million for the three months ended September 30, 2021 compared to the three months ended September 30, 2020 due to the sale of our natural gas storage facilities in August 2021. The impact on net revenues of the sale of these facilities was nearly entirely offset for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to increased margins from hub activities in the first quarter of 2021 related to Winter Storm Uri.

Field Operating Costs. The increase in field operating costs for the three and nine months ended September 30, 2021 compared to the same periods in 2020 was primarily due to (i) higher compensation costs, including lower wage subsidies received by our Canadian subsidiary in the 2021 periods, (ii) costs associated with a fire at our Fort Saskatchewan facility, and (iii) higher power costs due to increased volumes at our NGL fractionation plants. These unfavorable impacts were partially offset for the (i) three and nine months due to the sale of our Los Angeles Basin terminals in October 2020 and natural gas storage facilities in August 2021 and reduced activity at our rail terminals and (ii) nine months due to the sale of certain NGL terminals in the second quarter of 2020.

Maintenance Capital. The increase in maintenance capital spending for the three months ended September 30, 2021 compared to the same period in 2020 was primarily due to timing of certain projects across multiple facilities.

Supply and Logistics Segment

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

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

Operating Results [1]	**Three Months Ended September 30,**		**Variance**		**Nine Months Ended September 30,**		**Variance**	
(in millions, except per barrel data)	**2021**	**2020**	**$**	**%**	**2021**	**2020**	**$**	**%**
Revenues	$ 10,515	$ 5,537	$ 4,978	90 %	$ 28,222	$ 16,371	$ 11,851	72 %
Purchases and related costs	(10,488)	(5,510)	(4,978)	(90)%	(27,985)	(16,227)	(11,758)	(72)%
Field operating costs	(43)	(46)	3	7 %	(126)	(149)	23	15 %
Segment general and administrative expenses [2]	(22)	(21)	(1)	(5)%	(66)	(65)	(1)	(2)%
Adjustments: [3]								
(Gains)/losses from derivative activities and inventory valuation adjustments	22	94	(72)	**	(3)	215	(218)	**
Long-term inventory costing adjustments	(13)	2	(15)	**	(81)	66	(147)	**
Equity-indexed compensation expense	2	1	1	**	3	3	—	**
Net (gain)/loss on foreign currency revaluation	3	4	(1)	**	2	(9)	11	**
Significant transaction-related expenses	1	—	1	**	3	—	3	**
Segment Adjusted EBITDA	$ (23)	$ 61	$ (84)	(138)%	$ (31)	$ 205	$ (236)	(115)%
Maintenance capital	$ 3	$ 9	$ (6)	(67)%	$ 9	$ 19	$ (10)	(53)%
Segment Adjusted EBITDA per barrel	$ (0.17)	$ 0.54	$ (0.71)	(131)%	$ (0.08)	$ 0.57	$ (0.65)	(114)%

Average Daily Volumes [4]	**Three Months Ended September 30,**		**Variance**		**Nine Months Ended September 30,**		**Variance**	
(in thousands of barrels per day)	**2021**	**2020**	**Volumes**	**%**	**2021**	**2020**	**Volumes**	**%**
Crude oil lease gathering purchases	1,372	1,147	225	20 %	1,300	1,181	119	10 %
NGL sales	87	83	4	5 %	139	132	7	5 %
Supply and Logistics segment total volumes	1,459	1,230	229	19 %	1,439	1,313	126	10 %

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

(1) Revenues and costs include intersegment amounts.

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

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 11 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.

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

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

	NYMEX WTI Crude Oil Price	
	Low	High
Three Months Ended September 30, 2021	$ 62	$ 75
Three Months Ended September 30, 2020	$ 37	$ 43
Nine Months Ended September 30, 2021	$ 48	$ 75
Nine Months Ended September 30, 2020	$ (38)	$ 63

Our crude oil and NGL supply, logistics and distribution operations 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 for both sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. Additionally, net revenues are impacted by net gains and losses from certain derivative activities and inventory valuation and costing adjustments.

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.

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

- *Crude Oil Operations.* Net revenues from our crude oil operations were lower for the three and nine months ended September 30, 2021 compared to the same periods in 2020 due to the impact of more favorable market conditions in 2020, primarily on contango margins.

- *NGL Operations.* Net revenues from our NGL operations were higher for the three and nine months ended September 30, 2021 compared to the same periods in 2020 due to (i) a decrease in intersegment fees in 2021 to reflect lower utilization and market rates (which had an offsetting unfavorable impact on our Facilities and Transportation segments) and (ii) higher realized margins associated with NGL processing and fractionation activities in the third quarter of 2021.

- *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 8 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities. These gains and losses impact our net revenues but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above.

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

- *Foreign Exchange Impacts.* Our net revenues are impacted by fluctuations in the value of CAD to USD, resulting in 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.

- *Field Operating Costs.* The decrease in field operating costs for the nine months ended September 30, 2021 compared to the same period in 2020 was primarily driven by lower trucking costs due to more supply connected to pipelines resulting in lower trucking activity in the 2021 period.

Other Income and Expenses

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and nine months ended September 30, 2021 compared to the same periods in 2020 was largely driven by a reduction in the useful lives of certain assets. See Note 2 to our Condensed Consolidated Financial Statements for additional information.

Gains/(Losses) on Asset Sales and Asset Impairments, Net

The net losses on asset sales and asset impairments for 2021 primarily include (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, which were sold on August 2, 2021, and (iii) a gain of $106 million recognized in the second quarter related to the Asset Exchange transaction. See Note 12 to our Condensed Consolidated Financial Statements for additional information. The net loss on asset sales and asset impairments for the nine months ended September 30, 2020 was largely driven by (i) non-cash impairment losses of approximately $446 million recognized in the first quarter related to the write-down of certain pipeline and other long-lived assets due to 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 (ii) approximately $167 million of impairment losses recognized on assets upon classification as held for sale during the first quarter, which were subsequently sold.

Goodwill Impairment Losses

During the first quarter of 2020, we recognized a goodwill impairment charge of $2.515 billion, representing the entire balance of goodwill.

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

During the three and nine months ended September 30, 2020, we recognized losses of $91 million and $202 million, respectively, related to the write-down of certain of our investments in unconsolidated entities. Additionally, during the nine months ended September 30, 2020, we recognized a gain of $21 million related to our sale of a 10% interest in Saddlehorn Pipeline Company, LLC.

Interest Expense

The decrease in interest expense for the three and nine months ended September 30, 2021 compared to the three and nine months ended September 30, 2020 was primarily due to a lower weighted average debt balance and lower average rates during the 2021 periods.

Other Income/(Expense), Net

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Gain/(loss) related to mark-to-market adjustment of our Preferred Distribution Rate Reset Option [(1)]	$ 4	$ (10)	$ 13	$ 7
Net gain/(loss) on foreign currency revaluation [(2)]	(15)	14	(1)	(20)
Other	1	1	1	6
	$ (10)	$ 5	$ 13	$ (7)

(1) See Note 8 to our Condensed Consolidated Financial Statements for additional information.

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

Income Tax (Expense)/Benefit

The net favorable income tax variance for the three and nine months ended September 30, 2021 compared to the three and nine months ended September 30, 2020 was primarily a result of activity within our Canadian operations.

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 our divestiture program and in the past we 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 September 30, 2021, although we had a working capital deficit of $523 million, we had approximately $2.8 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 September 30, 2021
Availability under senior unsecured revolving credit facility [(1)] [(2)]	$ 1,293
Availability under senior secured hedged inventory facility [(1)] [(2)]	1,343
Amounts outstanding under commercial paper program	—
Subtotal	2,636
Cash and cash equivalents	191
Total	$ 2,827

(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 $57 million and $7 million, respectively.

In August 2021, we entered into new and amended credit agreements to facilitate the renewal and extension of our credit facilities. Our $1.6 billion senior unsecured revolving credit facility with a maturity date of August 2024 was replaced with a $1.35 billion senior unsecured revolving credit facility with an initial maturity in August 2026 and our $1.4 billion senior secured hedged inventory facility with a maturity date of August 2022 was replaced with a $1.35 billion senior secured hedged inventory facility with an initial maturity in August 2024. The credit agreements provide for one or more one-year extensions and have accordion features which, subject to receipt of incremental lender approval and other terms and conditions, permit us to increase borrowing capacity under the senior unsecured revolving credit facility and senior secured hedged inventory facility to $2.1 billion and $1.9 billion, respectively. The covenants and events of default under the new and amended credit agreements remain substantially unchanged from the previous agreements. See Note 6 to our Condensed Consolidated Financial Statements for additional information.

Usage of our credit facilities, and, in turn, our commercial paper program, is subject to ongoing compliance with covenants. 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. Additionally, lack of compliance with the provisions in our credit agreements may restrict our ability to make distributions of available cash. We were in compliance with the covenants contained in our credit agreements and indentures as of September 30, 2021.

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 Organization of Petroleum Exporting Countries (“OPEC”). A prolonged material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity and cost of borrowing. Our borrowing capacity and borrowing costs are also impacted by our credit rating. See Item 1A. “Risk Factors” included in our 2020 Annual Report on Form 10-K for further discussion regarding risks that may impact our liquidity and capital resources.

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 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 and base gas, net of proceeds from the sales of assets and further impacted by cash received from or paid to 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):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Net cash provided by operating activities	$ 336	$ 282	$ 1,361	$ 1,256
Adjustments to reconcile net cash provided by operating activities to free cash flow:				
Net cash provided by/(used in) investing activities	761	(208)	478	(1,066)
Cash contributions from noncontrolling interests	—	1	1	11
Cash distributions paid to noncontrolling interests (1)	(4)	(2)	(10)	(6)
Free Cash Flow	$ 1,093	$ 73	$ 1,830	$ 195
Cash distributions (2)	(166)	(168)	(526)	(661)
Free Cash Flow after Distributions	$ 927	$ (95)	$ 1,304	$ (466)

(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

For a comprehensive discussion of the primary drivers of cash flow from operating activities, including the impact of varying market conditions and the timing of settlement of our derivatives, see Item 7. “Liquidity and Capital Resources—Cash Flow from Operating Activities” included in our 2020 Annual Report on Form 10-K.

Net cash provided by operating activities for the first nine months of 2021 and 2020 was $1.361 billion and $1.256 billion, respectively, and primarily resulted from earnings from our operations. During the nine months ended September 30, 2020, we increased the volume of our crude oil inventory to be stored during the contango market; however, this increase was offset by lower prices for our inventory stored at the end of the current period compared to the end of 2019.

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 our divestiture program. 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):

	Nine Months Ended September 30,	
	2021	2020
Investment capital (1) (2)	$ 182	$ 785
Maintenance capital (1)	116	157
Acquisition capital (3)	32	310
	$ 330	$ 1,252

(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 12 to our Condensed Consolidated Financial Statements for additional information. Acquisition capital for 2020 primarily includes Felix Midstream LLC, a crude oil gathering system located in the Delaware Basin.

2021 Investment and Maintenance Capital. Total projected investment capital for the year ended December 31, 2021 is $275 million, a majority of which will be invested in our fee-based Transportation and Facilities segments. Additionally, maintenance capital for the full year of 2021 is projected to be $180 million. We expect to fund our 2021 investment and maintenance capital expenditures with retained cash flow and proceeds from assets sold as part of our divestiture program.

Divestitures

We continue to evaluate potential sales of non-core assets and/or sales of partial interests in assets to strategic joint venture partners. The following table summarizes the proceeds received during the first nine months of 2021 and 2020 from sales of assets, which were previously reported in our Transportation and Facilities segments (in millions):

	Nine Months Ended September 30,	
	2021	**2020**
Proceeds from divestitures [1]	$ 878	$ 246

(1) Represents gross proceeds, including working capital adjustments, before deducting transaction costs.

The proceeds from divestitures in 2021 are primarily from the sale of our Pine Prairie and Southern Pines natural gas storage facilities on August 2, 2021. See Note 12 to our Condensed Consolidated Financial Statements for additional information. Proceeds from divestitures were used to reduce debt levels and fund our investment capital projects.

Ongoing Activities Related to Strategic Transactions

We are continuously engaged in the evaluation of potential transactions that support our current business strategy. While in the past such transactions have included acquisitions and large capital projects, consistent with our current strategic focus on capital discipline, leverage reduction, portfolio optimization and free cash flow generation, we are currently primarily focused on evaluating whether we should (i) sell assets that we regard as non-core or that we believe might be a better fit with the business and/or assets of a third-party buyer or (ii) sell partial interests in assets to strategic joint venture partners, in each case to optimize our asset portfolio and strengthen our balance sheet and leverage metrics. With respect to a potential divestiture, we may also conduct an auction process or may negotiate a transaction with one or a limited number of potential buyers. Such transactions could involve assets that, if sold or put into a joint venture or joint ownership arrangement, could have a material effect on our financial condition and results of operations.

We typically do not announce a transaction until after we have executed a definitive agreement. However, in certain cases in order to protect our business interests or for other reasons, we may defer public announcement of a transaction until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential transaction can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive agreement may be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future efforts with respect to any such transactions will be successful, and we can provide no assurance that our financial expectations with respect to such transactions will ultimately be realized. See Item 1A. “Risk Factors—Risks Related to Our Business—Divestitures, joint ventures, joint ownership arrangements and acquisitions involve risks that may adversely affect our business” included in our 2020 Annual Report on Form 10-K.

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 nine months ended September 30, 2021, we had net repayments on our credit facilities and commercial paper program of $713 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 nine months ended September 30, 2020, we had net repayments on our credit facilities and commercial paper program of $306 million. The net repayments resulted primarily from cash flow from operating activities, proceeds from asset sales and the issuance of $750 million, 3.80% senior notes in June 2020, which offset borrowings during the period related to funding needs for capital investments, inventory purchases and other general partnership purposes.

In connection with the sale of our Pine Prairie and Southern Pines natural gas storage facilities on August 2, 2021, we repaid our two GO Zone term loans totaling $200 million. See Note 12 for additional information regarding the sale of our natural gas storage facilities.

Common Equity Repurchase Program

We repurchased 11,917,303 common units under the Program through open market purchases that settled during the nine months ended September 30, 2021. The total purchase price of these repurchases was $117 million, including commissions and fees. At September 30, 2021, the remaining available capacity under the Program was $333 million.

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, in the aggregate, 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 September 30, 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. We did not conduct any offerings under our Traditional Shelf or WKSI Shelf during the nine months ended September 30, 2021.

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" included in our 2020 Annual Report on Form 10-K for additional discussion regarding distributions.

See Note 7 to our Condensed Consolidated Financial Statements for details of distributions paid during or pertaining to the first nine months of 2021.

Contingencies

For a discussion of contingencies that may impact us, see Note 10 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to 12 years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with our counterparties (including giving effect to netting buy/sell contracts and those subject to a net settlement arrangement). We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

The following table includes our best estimate of the amount and timing of these payments as well as other amounts due under the specified contractual obligations as of September 30, 2021 (in millions):

	Remainder of 2021	2022	2023	2024	2025	2026 and Thereafter	Total
Long-term debt and related interest payments [1]	$ 101	$ 1,138	$ 1,463	$ 1,085	$ 1,303	$ 8,339	$ 13,429
Leases [2]	28	106	86	73	58	331	682
Other obligations [3]	82	337	338	282	267	943	2,249
Subtotal	211	1,581	1,887	1,440	1,628	9,613	16,360
Crude oil, NGL and other purchases [4]	6,868	21,598	19,989	18,909	15,882	61,185	144,431
Total	$ 7,079	$ 23,179	$ 21,876	$ 20,349	$ 17,510	$ 70,798	$ 160,791

(1) Includes debt service payments, interest payments due on senior notes and the commitment fee on assumed available capacity under our credit facilities, as well as long-term borrowings under our credit agreements and commercial paper program, if any. Although there may be short-term borrowings under our credit agreements and commercial paper program, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the credit agreements or commercial paper program) in the amounts above. For additional information regarding our debt obligations, see Note 6 to our Condensed Consolidated Financial Statements.

(2) Includes both operating and finance leases as defined by FASB guidance. Leases are primarily for (i) railcars, (ii) land, (iii) office space, (iv) storage tanks, (v) tractor trailers and (vi) vehicles. See Note 14 to our Consolidated Financial Statements included in Part IV of our 2020 Annual Report on Form 10-K for additional information.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements (including certain agreements for which the amount and timing of expected payments is subject to the completion of underlying construction projects), (iii) certain rights-of-way easements and (iv) noncancelable commitments related to our investment capital projects, including projected contributions for our share of the capital spending of our equity method investments. The storage, processing and transportation agreements include approximately $1.8 billion associated with agreements to store crude oil at facilities and transport crude oil or utilize capacity on pipelines owned by equity method investees at posted tariff rates or prices that we believe approximate market. A portion of our commitment to transport is supported by crude oil buy/sell or other agreements with third parties with commensurate quantities.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during September 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 supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At September 30, 2021 and December 31, 2020, we had outstanding letters of credit of approximately $64 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.

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Item 7 of our 2020 Annual Report on Form 10-K.

Change in Accounting Estimate

In early 2021, we conducted a review to assess the useful lives of our property and equipment. Based on this review, we modified the useful lives of certain of our Pipelines and related facilities and Storage, terminal and rail facilities to useful lives of 10 to 50 years from useful lives of 10 to 70 years to reflect current expectations given our future operating and commercial outlook. This change in accounting estimate was effective January 1, 2021. Based on the net carrying amount of this property and equipment as of January 1, 2021, we currently estimate that these useful life reductions will prospectively increase annual depreciation expense by approximately $72 million.

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words “anticipate,” “believe,” “estimate,” “expect,” “plan,” “intend” and “forecast,” as well as similar expressions and statements regarding our business strategy, plans and objectives for future operations. The absence of such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- declines in global crude oil demand and crude oil prices (whether due to the COVID-19 pandemic, future pandemics or other factors) that correspondingly lead to a significant reduction of North American crude oil, natural gas liquids (“NGL”) and natural gas production (whether due to reduced producer cash flow to fund drilling activities or the inability of producers to access capital, or both, the unavailability of pipeline and/or storage capacity, the shutting-in of production by producers, government-mandated pro-ration orders, or other factors), which in turn could result in significant declines in the actual or expected volume of crude oil and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets and/or the reduction of commercial opportunities that might otherwise be available to us;
- the effects of competition and capacity overbuild in areas where we operate, including contract renewal risk and the risk of loss of business to other midstream operators who are willing or under pressure to aggressively reduce transportation rates in order to capture or preserve customers;
- negative societal sentiment regarding the hydrocarbon energy industry and the continued development and consumption of hydrocarbons, which could influence consumer preferences and governmental or regulatory actions that adversely impact our business;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, NGL and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- the availability of, and our ability to consummate, divestitures, joint ventures, acquisitions or other strategic opportunities;
- the successful operation of joint ventures and joint operating arrangements we enter into from time to time, whether relating to assets operated by us or by third parties, and the successful integration and future performance of acquired assets or businesses;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event that materially impacts our operations, including cyber or other attacks on our electronic and computer systems;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the refusal or inability of our customers or counterparties to perform their obligations under their contracts with us (including commercial contracts, asset sale agreements and other agreements), whether justified or not and whether due to financial constraints (such as reduced creditworthiness, liquidity issues or insolvency), market constraints, legal constraints (including governmental orders or guidance), the exercise of contractual or common law rights that allegedly excuse their performance (such as force majeure or similar claims) or other factors;
- our inability to perform our obligations under our contracts, whether due to non-performance by third parties, including our customers or counterparties, market constraints, third-party constraints, legal constraints (including governmental orders or guidance), or other factors;
- the incurrence of costs and expenses related to unexpected or unplanned capital expenditures, third-party claims or other factors;
- disruptions to futures markets for crude oil, NGL and other petroleum products, which may impair our ability to execute our commercial or hedging strategies;
- failure to implement or capitalize, or delays in implementing or capitalizing, on investment capital projects, whether due to permitting delays, permitting withdrawals or other factors;
- shortages or cost increases of supplies, materials or labor;
- the impact of current and future laws, rulings, governmental regulations, trade policies, accounting standards and statements, and related interpretations, including legislation or regulatory initiatives that prohibit, restrict or regulate hydraulic fracturing or that prohibit the development of oil and gas resources and the related infrastructure on lands dedicated to or served by our pipelines;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, investment capital projects, working capital requirements and the repayment or refinancing of indebtedness;
- general economic, market or business conditions in the United States and elsewhere (including the potential for a recession or significant slowdown in economic activity levels and the timing, pace and extent of economic recovery) that impact demand for crude oil, drilling and production activities and therefore the demand for the midstream services we provide and commercial opportunities available to us;
- the amplification of other risks caused by volatile financial markets, capital constraints, liquidity concerns and inflation;
- the use or availability of third-party assets upon which our operations depend and over which we have little or no control;
- the currency exchange rate of the Canadian dollar to the United States dollar;
- inability to recognize current revenue attributable to deficiency payments received from customers who fail to ship or move more than minimum contracted volumes until the related credits expire or are used;
- significant under-utilization of our assets and facilities;

- increased costs, or lack of availability, of insurance;
- the effectiveness of our risk management activities;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- risks related to the development and operation of our assets; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, as well as in the processing, transportation, fractionation, storage and marketing of NGL.

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read “Risk Factors” discussed in Item 1A of our 2020 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

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

- *Crude oil*

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

- *NGL and other*

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

See Note 8 to our Condensed 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 September 30, 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	$ (4)	$ 4	$ (3)
Natural gas	78	$ 24	$ (24)
NGL and other	(425)	$ (114)	$ 114
Total fair value	$ (351)		

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 September 30, 2021. The fair value of our interest rate derivatives was a net asset of $81 million as of September 30, 2021. A 10% increase in the forward LIBOR curve as of September 30, 2021 would have resulted in an increase of $17 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of September 30, 2021 would have resulted in a decrease of $17 million to the fair value of our interest rate derivatives. See Note 8 to our Condensed Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives was a liability of $1 million as of September 30, 2021. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in an increase of $12 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in a decrease of $12 million to the fair value of our foreign currency derivatives. See Note 8 to our Condensed Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Preferred Distribution Rate Reset Option

The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value in our Condensed 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 a liability of $1 million as of September 30, 2021. A 10% increase or decrease in the fair value would have an impact of less than $1 million. See Note 8 to our Condensed Consolidated Financial Statements for a discussion of embedded derivatives.

Item 4. 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 September 30, 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.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting during the third 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.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included in Note 10 to our Condensed Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion of our risk factors, see Item 1A. of our 2020 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Sales of Unregistered Securities

The Omnibus Agreement, entered into as part of the Simplification Transactions, which closed on November 15, 2016, provides for the mechanics by which (i) the total number of PAGP’s outstanding Class A shares will equal the number of AAP units held by PAGP, and (ii) the total number of our common units held by AAP will equal the sum of the number of outstanding Class A units of AAP (“AAP units”) and the number of AAP units that are issuable to the holders of vested and earned Class B units of AAP (“AAP Management Units”). As such, we are obligated to issue common units to AAP in connection with PAGP’s issuance of Class A shares upon PAGP LTIP award vestings. During the three months ended September 30, 2021, we issued 18,546 common units to AAP in connection with PAGP LTIP award vestings. This issuance was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Issuer Purchases of Equity Securities

The following table summarizes our equity repurchase activity during the third 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	Approximate Dollar Value of Common Units that May Yet Be Purchased under the Program [2]
August 1, 2021 - August 31, 2021	5,126,711	$ 9.77	5,126,711	$ 346,761,612
September 1, 2021 - September 30, 2021	1,500,000	$ 9.39	1,500,000	$ 332,701,962

(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 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.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

Exhibit No.		Description
2.1*	—	Agreement and Plan of Merger dated as of July 12, 2021 by and among Plains Pipeline, L.P., Plains Marketing, L.P., Oryx Midstream Holdings LLC, Middle Cadence Holdings LLC, POP HoldCo LLC, Oryx Wink Oil Marketing LLC, Oryx Permian Oil Marketing LLC, Plains Oryx Permian Basin LLC, Plains Oryx Permian Basin Marketing LLC and Plains Oryx Permian Basin Pipeline LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed July 13, 2021).
3.1	—	Seventh Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of October 10, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 12, 2017).
3.2	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.4	—	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.5	—	Amendment No. 3 dated June 30, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.6	—	Amendment No. 4 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P (incorporated by reference to Exhibit 3.8 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.7	—	Amendment No. 5 dated December 1, 2019 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to our Annual Report on Form 10-K for the year ended December, 31, 2019).
3.8	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	—	Amendment No. 1 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.10	—	Seventh Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated November 15, 2016 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed November 21, 2016).

3.11	—	Eighth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated November 15, 2016 (incorporated by reference to Exhibit 3.4 to our Current Report on Form 8-K filed November 21, 2016).
3.12	—	Amendment No. 1 dated September 26, 2018 to the Eighth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 2, 2018).
3.13	—	Amendment No. 2 dated May 23, 2019 to the Eighth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed May 30, 2019).
3.14	—	Certificate of Incorporation of PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2006).
3.15	—	Bylaws of PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to our Annual Report on Form 10-K for the year ended December 31, 2006).
3.16	—	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed January 4, 2008).
3.17	—	Certificate of Limited Partnership of Plains GP Holdings, L.P. (incorporated by reference to Exhibit 3.1 to PAGP’s Registration Statement on Form S-1 (333-190227) filed July 29, 2013).
3.18	—	Second Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P. dated November 15, 2016 (incorporated by reference to Exhibit 3.2 to PAGP’s Current Report on Form 8-K filed November 21, 2016).
3.19	—	Amendment No. 1 dated April 6, 2020 to the Second Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P. (incorporated by reference to Exhibit 3.1 to PAGP’s Current Report on Form 8-K filed April 9, 2020).
3.20	—	Certificate of Formation of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.3 to PAGP’s Registration Statement on Form S-1 (333-190227) filed July 29, 2013).
3.21	—	Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC dated as of February 16, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed February 21, 2017).
3.22	—	Amendment No. 1 dated October 1, 2018 to the Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed August 20, 2018).
3.23	—	Amendment No. 2 dated December 10, 2018 to the Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed December 11, 2018).
3.24	—	Amendment No. 3 dated November 21, 2019 to the Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed November 27, 2019).
3.25	—	Amendment No. 4 dated February 25, 2021 to the Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed March 3, 2021).
3.26	—	Amendment No. 5 dated August 19, 2021 to the Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC dated as of February 17, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed August 19, 2021).
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).

4.2	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed May 12, 2006).
4.3	—	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed October 30, 2006).
4.4	—	Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed March 26, 2012).
4.5	—	Twenty-First Supplemental Indenture (5.15% Senior Notes due 2042) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed March 26, 2012).
4.6	—	Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 12, 2012).
4.7	—	Twenty-Third Supplemental Indenture (4.30% Senior Notes due 2043) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 12, 2012).
4.8	—	Twenty-Fourth Supplemental Indenture (3.85% Senior Notes due 2023) dated August 15, 2013, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 15, 2013).
4.9	—	Twenty-Fifth Supplemental Indenture (4.70% Senior Notes due 2044) dated April 23, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 29, 2014).
4.10	—	Twenty-Sixth Supplemental Indenture (3.60% Senior Notes due 2024) dated September 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 11, 2014).
4.11	—	Twenty-Eighth Supplemental Indenture (4.90% Senior Notes due 2045) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 11, 2014).
4.12	—	Twenty-Ninth Supplemental Indenture (4.65% Senior Notes due 2025) dated August 24, 2015, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 26, 2015).
4.13	—	Thirtieth Supplemental Indenture (4.50% Senior Notes due 2026) dated November 22, 2016, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed November 29, 2016).
4.14	—	Thirty-First Supplemental Indenture (3.55% Senior Notes due 2029) dated September 16, 2019, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 17, 2019).
4.15	—	Thirty-Second Supplemental Indenture (3.80% Senior Notes due 2030) dated June 11, 2020, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed June 11, 2020).

4.16	—	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to our Registration Statement on Form S-3, File No. 333-162477).
4.17	—	Registration Rights Agreement dated as of January 28, 2016 among Plains All American Pipeline, L.P. and the Purchasers named therein (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed February 2, 2016).
4.18	—	Registration Rights Agreement by and among Plains All American Pipeline, L.P. and the Holders defined therein, dated November 15, 2016 (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed November 21, 2016).
4.19	—	Description of Our Securities (incorporated by reference to Exhibit 4.19 to our Annual Report on Form 10-K for the year ended December 31, 2020).
10.1	—	Credit Agreement dated as of August 20, 2021, among Plains All American Pipeline, L.P. and Plains Midstream Canada ULC, as Borrowers; certain subsidiaries of Plains All American Pipeline, L.P. from time to time party thereto, as Designated Borrowers; Bank of America, N.A., as Administrative Agent and Swing Line Lender; Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association, as L/C Issuers; and the other Lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 26, 2021).
10.2	—	Fourth Amended and Restated Credit Agreement dated as of August 20, 2021, among Plains Marketing, L.P. and Plains Midstream Canada ULC, as Borrowers; Plains All American Pipeline, L.P., as guarantor; Bank of America, N.A., as Administrative Agent and Swing Line Lender; Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association, as L/C Issuers; and the other Lenders party thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed August 26, 2021).
10.3** †	—	Form of LTIP Grant Letter dated August 19, 2021 (Named Executive Officers).
10.4** †	—	Form of LTIP Grant Letter dated August 19, 2021 (Directors).
31.1 †	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2 †	—	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1 ††	—	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
32.2 ††	—	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.
101.INS†	—	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH†	—	Inline XBRL Taxonomy Extension Schema Document
101.CAL†	—	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	—	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	—	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE†	—	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104†	—	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

† Filed herewith.

†† Furnished herewith.

* Certain schedules and similar attachments have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Registrant agrees to furnish a supplemental copy of any omitted schedule or attachment to the SEC upon request.

** Management compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC,
its general partner

By: Plains AAP, L.P.,
its sole member

By: Plains All American GP LLC,
its general partner

By: /s/ Willie Chiang
Willie Chiang,
Chief Executive Officer of Plains All American GP LLC
(Principal Executive Officer)

November 8, 2021

By: /s/ Al Swanson
Al Swanson,
Executive Vice President and Chief Financial Officer of Plains All American GP LLC
(Principal Financial Officer)

November 8, 2021

By: /s/ Chris Herbold
Chris Herbold,
Senior Vice President, Finance and Chief Accounting Officer of Plains All American GP LLC
(Principal Accounting Officer)

November 8, 2021

Exhibit 10.3

PLAINS ALL AMERICAN

2021 Regular Annual LTIP Grant
Section 16 Officers

August 19, 2021

«Section 16 Officer»
«Address»

Re: Grant of Phantom Units

Dear «Salutation»:

I am pleased to inform you that, subject to the terms hereof, you have been granted a target number of Phantom Units equal to «LTIP_Grant» as of the above date pursuant to the Company's «LTIP_Plan» Long-Term Incentive Plan (the "Plan"). In addition, in tandem with each Phantom Unit you have been granted a distribution equivalent right (a "DER"). A DER represents the right to receive a cash payment equivalent to the amount, if any, paid in cash distributions on one Common Unit of Plains All American Pipeline, L.P. ("PAA" or the "Partnership") to the holder of such Common Unit. The terms and conditions of this grant are as set forth below.

1. Subject to the further provisions hereof, your Phantom Units shall vest (become payable in the form of one Common Unit of PAA for each Phantom Unit that vests) as set forth below. With respect to Tranche 2 and Tranche 3 below, the actual number of Phantom Units that vest may be lower or higher than the percentage of target Phantom Units associated with such Tranche.
    a. 50% of your Phantom Units ("Tranche 1") will vest on the August 2024 Distribution Date.
    b. 25% of your Phantom Units ("Tranche 2") will vest pursuant to the terms and conditions described in Exhibit A attached hereto.
    c. 25% of your Phantom Units ("Tranche 3") will vest pursuant to the terms and conditions described in Exhibit B attached hereto.
    d. Any Tranche 2 or Tranche 3 Phantom Units that are determined not to have vested as of the August 2024 Distribution Date shall expire effective as of such date.

2. Subject to the further provisions hereof, your DERs shall vest (become payable in cash) as follows:
    a. The DERs associated with Tranche 1 will begin accruing on the November 2021 Distribution Date and will continue to accrue until the August 2022 Distribution Date, on which date such accrued but unpaid DERs will vest and be paid in a lump sum. Beginning on the November 2022 Distribution Date, such vested DERs will be paid quarterly until the associated Phantom Units vest or are forfeited pursuant to the terms hereof.

b. The DERs associated with Tranches 2 and 3 will begin accruing on the November 2021 Distribution Date and will continue to accrue until the associated Phantom Units vest or are forfeited pursuant to the terms hereof. Until such time as a final determination has been made regarding the number of Phantom Units that have vested for Tranche 2 and Tranche 3, such accruals will be based on the assumption that the final "Payout Percentage" as determined pursuant to Exhibit A or Exhibit B, as applicable, equals 100%. Once the final Payout Percentages and the final number of Phantom Units vesting for Tranche 2 and Tranche 3 have been determined, such accrued amounts shall be adjusted upward or downward, as applicable, so that they equal the total amount that would have been accrued in respect of the DERs associated with such vested Phantom Units had the accrual been based on such number of vested Phantom Units commencing on the November 2021 Distribution Date. All accrued and unpaid DERs associated with Tranche 2 and Tranche 3 shall be paid on the August 2024 Distribution Date or as soon thereafter as is administratively practicable.

3. The number of Phantom Units and DERs subject to this award, and with respect to the Phantom Units comprising Tranche 3, the distributable cash flow level required for vesting of such Phantom Units, shall be proportionately reduced or increased for any split or reverse split, respectively, of PAA Common Units, or any event or transaction having a similar effect.

4. Upon vesting of any Phantom Units, an equivalent number of DERs will expire. Any such DERs that are payable on the Distribution Date on which the Phantom Units vest, shall be payable on such Distribution Date prior to their expiration.

5. In the event of the termination of your employment with the Company and its Affiliates for any reason (other than in connection with a Change in Status or by reason of your death or “disability,” as defined in paragraph 6 below), all of your then outstanding Phantom Units and DERs shall automatically be forfeited as of the date of termination; provided, however, that if the Company or its Affiliates terminate your employment other than as a result of a Termination for Cause, the following provisions shall apply: (i) if such termination takes place prior to the first anniversary of the date of this grant, all of your then outstanding Phantom Units and DERs shall automatically be forfeited as of the date of termination; and (ii) if such termination takes place after the first anniversary of the date of this grant, a “pro rata portion” of the target number of your then outstanding Phantom Units and DERs shall be deemed nonforfeitable on the date of termination and shall vest on the next following Distribution Date. The “pro rata portion” of Phantom Units vesting pursuant to clause (ii) immediately preceding shall be determined by multiplying the target number of your then outstanding Phantom Units by a fraction equal to the number of days between the grant date and the date of termination divided by the number of days between the grant date and the August 2024 Distribution Date (1,090). If the resulting amount includes a fraction, it will be rounded down to the nearest whole number.

6. In the event of the termination of your employment with the Company and its Affiliates by reason of your death or your “disability” (a physical or mental infirmity that impairs your ability substantially to perform your duties for a period of eighteen months or that the Company otherwise determines constitutes a “disability”), the following provisions shall apply: (i) if such termination takes place prior to the first anniversary of the date of this grant, all of your then outstanding Phantom Units and DERs shall automatically be forfeited as of the date of termination; and (ii) if such termination takes place on or after the first anniversary of the date of this grant, (x) all of your then outstanding Phantom Units (which shall be equal to the target number of Phantom Units specified in the first paragraph hereof) shall be deemed nonforfeitable on the date of termination and shall vest on the next following Distribution Date, and (y) any DERs associated with such unvested, nonforfeitable Phantom Units shall not be forfeited on the date of termination, but shall be payable and shall expire on the next following Distribution Date. As soon as administratively practicable after the vesting of any Phantom Units pursuant to this paragraph 6, payment will be made in cash in an amount equal to the Market Value of the number of Phantom Units vesting.

7. In the event of a Change in Status, (i) all of your then outstanding Phantom Units (which shall be equal to the target number of Phantom Units specified in the first paragraph hereof) shall be deemed nonforfeitable on such date and shall vest on the next following Distribution Date, and (ii) any DERs associated with such unvested, nonforfeitable Phantom Units shall not be forfeited on such date, but shall be payable and shall expire on the next following Distribution Date.

8. Upon payment pursuant to a DER, the Company will withhold any taxes due from your compensation as required by law. Upon vesting of a Phantom Unit, the Company will withhold any taxes due from your compensation as required by law, which (in the sole discretion of the Company) may include withholding a number of Common Units otherwise payable to you.

As used herein, (i) the “Company” refers to Plains All American GP LLC; (ii) “Distribution Date” means the day in February, May, August or November in any year (as context dictates) that is 45 days after the end of the most recently completed calendar quarter (or, if not a business day, the closest previous business day); and (iii) “Market Value” means the average of the closing sales prices for a Common Unit on Nasdaq for the five trading days preceding the then most recent “ex dividend” date for payment of a distribution by the Partnership.

The phrase “Change in Status” means (A) the termination of your employment by the Company other than a Termination for Cause, within two and a half months prior to or one year following a Change of Control (the “Protected Period”), (B) the termination of your employment by you due to the occurrence during the Protected Period, without your written consent, of (i) any material diminution in your authority, duties or responsibilities, (ii) any material reduction in your base salary, or (iii) any other action or inaction that constitutes a material breach of this Agreement by the Company, or (C) the termination of your employment by you as a result of your retirement on terms and timing that are approved by the CEO. A termination by you pursuant to (B) above shall not be a Change in Status unless (1) you provide written notice to the Company of the condition in (B)(i), (ii) or (iii) that would constitute a Change in Status within 90 days of the initial existence of the condition, and (2) the Company fails to remedy the condition within the 30-day period following such notice.

The phrase “Change of Control” means, and shall be deemed to have occurred upon the occurrence of, one or more of the following events:

(i) any Person (other than Plains GP Holdings, L.P. (“PAGP”) and any affiliate of PAGP that is controlled by PAGP) becomes the beneficial owner, directly or indirectly (in one transaction or a series of related transactions and whether by merger or otherwise), of 50% or more of the membership interest in PAA GP Holdings LLC, a Delaware limited liability company (“PAGP GP”);

(ii) any Person (other than PAGP GP, PAGP or any affiliate of PAGP that is controlled by PAGP) acquires (in one transaction or a series of related transactions and whether by merger or otherwise) direct or indirect control of the general partner interest of PAGP;

(iii) PAGP ceases to retain direct or indirect control (in one transaction or a series of related transactions and whether by merger or otherwise) of the general partner of the Partnership; or

(iv) the consummation of a reorganization, merger or consolidation with, or any direct or indirect sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Partnership to, one or more Persons (other than PAGP or any affiliates of PAGP that are controlled by PAGP).

As used in this definition, "Person" shall include any "partnership, limited partnership, syndicate or other group" constituting a "person" within the meaning of such terms pursuant to Sections 13(d) and 14(d) of the Securities Exchange Act of 1934, as amended.

The phrase "Termination for Cause" shall mean severance of your employment with the Company or its Affiliates based on your (i) failure to perform the duties and responsibilities of your position at an acceptable level as reasonably determined in good faith by the CEO of the Company, (ii) conviction of or guilty plea to the committing of an act or acts constituting a felony under the laws of the United States or any state thereof (or Canada or any province thereof) or any misdemeanor involving moral turpitude, or (iii) violation of the Company's Code of Business Conduct (unless waived in accordance with the terms thereof), in the case of clauses (i) and (iii), with the specific failure or violation described to you in writing.

Terms used herein that are not defined herein shall have the meanings set forth in the Plan or, if not defined in the Plan, in the Seventh Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., as amended (the "Partnership Agreement").

This award is intended to either (i) qualify as a "short-term deferral" under Section 409A of the Internal Revenue Code of 1986, as amended, or (ii) comply with the provisions of Section 409A. If it is determined that any payments or benefits to be made or provided under this Agreement do not comply with Section 409A, the parties agree to amend this Agreement or take such other actions as reasonably necessary or appropriate to comply with Section 409A while preserving the economic agreement of the parties.

By signing below, you agree that the Phantom Units and DERs granted hereunder are governed by the terms of the Plan. You also acknowledge and agree that (i) Tranches 2 and 3 of this award constitute performance-based compensation as defined in the Clawback Policy adopted by PAGP GP on November 12, 2020 and (ii) Tranches 2 and 3 of this award, as well as any other performance-based compensation previously paid or awarded to you, are subject to recovery or cancellation pursuant to such Policy. Copies of the Plan, the Partnership Agreement and the Clawback Policy are available upon request.

Please designate in the space provided below a beneficiary to receive benefits payable under this grant in the event of your death. Unless you indicate otherwise by checking the box below, the named beneficiaries on this form will serve as your beneficiaries for all previous LTIP grants. In addition, please execute and return a copy of this grant letter to me and retain a copy for your records.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC, its general partner
By: PLAINS AAP, L.P., its sole member
By: PLAINS ALL AMERICAN GP LLC,
its general partner

By: ______________________________
Name: Jim Tillis
Title: Vice President – Human Resources

____
«Section 16 Officer»

Target Number of Phantom Units: «LTIP Grant»

Dated: ________________________

Beneficiary Designation

Primary Beneficiary Name	Relationship	Percent (Must total 100%)
Secondary Beneficiary Name	Relationship	Percent (Must total 100%)

☐ Check this box only if this beneficiary designation does not apply to prior grants.

Exhibit A

Tranche 2 Vesting Terms
(Total Shareholder Return)

1. *General*. Consistent with the Company's pay for performance philosophy and in order to more closely align the interests of management with the interests of investors, a portion of your Phantom Units will vest based on PAA's total shareholder return ("TSR") compared to the TSR of a peer group as described below. TSR, which will be calculated using data from Bloomberg, is a primary long-term measure of PAA's performance.

2. *Vesting and Payout*. As soon as administratively feasible following the close of the three-year period ending on June 30, 2024 (the "Performance Period"), the Compensation Committee shall determine and certify the TSR Payout Percentage (as defined below). The Compensation Committee shall make such determination based on a scaled payout range of between 0% and 200% as provided in the table below (the specific payout percentage is referred to as the "TSR Payout Percentage") based on PAA's TSR ranking at the end of the Performance Period compared to the TSR ranking of the various companies included in the PAA Peer Group described below. If PAA's absolute TSR is within 50 basis points of the TSR of one or more peer group comparators (i.e., 50 basis points higher or lower), PAA and such comparator(s) shall be deemed to have the same rank and the TSR Payout Percentage shall be equal to the average of the TSR Payout Percentages associated with the relevant rankings as set forth in the table below. If PAA's absolute TSR at the end of the Performance Period is less than 0% and the TSR Payout Percentage is greater than 100%, (i) a TSR Payout Percentage above 125% will be reduced by 25 gross percentage points, and (ii) a TSR Payout Percentage between 100% and 125% will be reduced to 100%. The number of Tranche 2 Phantom Units vesting will be determined by multiplying your target number of Tranche 2 Phantom Units by the TSR Payout Percentage as certified by the Compensation Committee. If the resulting amount includes a fraction, it will be rounded down to the nearest whole number.

PAA TSR Ranking vs. PAA Peer Group	**TSR Payout Percentage**
1	200.0%
2	200.0%
3	185.6%
4	171.5%
5	157.1%
6	142.9%
7	128.5%
8	114.4%
9	100.0%
10	87.6%
11	75.0%
12	62.6%
13	50.0%
14	37.6%
15	25.0%
16	0%
17	0%

Illustrative Examples (based on an assumed target number of Tranche 2 Phantom Units of 1,000):

PAA TSR Ranking vs. PAA Peer Group	TSR Payout Percentage / Number of Units Vesting (impact of negative absolute TSR)
#1 or #2	200% / 2,000 units
#5	157.1% / 1,571 units
#5, but PAA's absolute TSR is less than 0%	132.1% / 1,321 units (TSR Payout Percentage reduced by 25 percentage points)
#8	114.4% / 1,144 units
#8, but PAA's absolute TSR is less than 0%	100% / 1,000 units (TSR Payout Percentage reduced from 114.4% to 100%)
#9	100% / 1,000 units (performance at Target)
#13	50% / 500 units
#16 or #17	0% / 0 units

3. *PAA Peer Group (2021-2024 Performance Period)*:

Company Name	Ticker
Enterprise Products Partners LP	EPD
Kinder Morgan Inc.	KMI
The Williams Companies Inc.	WMB
MPLX LP	MPLX
Energy Transfer LP	ET
ONEOK Inc.	OKE
Magellan Midstream Partners LP	MMP
Phillips 66 Partners LP	PSXP
Targa Resources Corp.	TRGP
DCP Midstream LP	DCP
Western Midstream Partners LP	WES
Holly Energy Partners LP	HEP
NuStar Energy LP	NS
EnLink Midstream LLC	ENLC
Alerian Midstream Energy Index	AMNA
S&P 500 Index	SPX

In the event any member of the PAA Peer Group files for bankruptcy, liquidates or reorganizes under the United States Bankruptcy Code or other applicable bankruptcy law, such entity shall remain in the PAA Peer Group but shall be deemed to have a TSR of -100% for purposes of calculating the TSR Payout Percentage. If any member of the PAA Peer Group is acquired by an unrelated entity before the end of the Performance Period, such member shall be removed from the PAA Peer Group for purposes of calculating the TSR Payout Percentage. The Compensation Committee shall have discretionary authority to replace such member for purposes of calculating the TSR Payout Percentage. In all other cases involving merger, reorganization or other material change in ownership, legal structure or business operations of any member of the PAA Peer Group, including acquisition by a related entity before the end of the Performance Period, the Compensation Committee shall have authority to retain, remove or replace such member for purposes of calculating the TSR Payout Percentage. In connection with any change to the PAA Peer Group, the Compensation Committee shall also have authority to make related adjustments to the rankings and TSR Payout Percentages.

Exhibit B

Tranche 3 Vesting Terms
(Cumulative DCF with Leverage Modifier)

1. *General*. Consistent with the Company's pay for performance philosophy and in order to more closely align the interests of management with the interests of investors, a portion of your Phantom Units will vest based on PAA's cumulative distributable cash flow ("DCF") per common unit equivalent ("CUE") over a three-year period as described below. PAA's ability to sustain and increase DCF is a primary long-term measure of PAA's performance and is consistent with PAA's overall financial strategy. The final payout calculation will be subject to modification based on leverage levels at the end of the Performance Period; the purpose of the potential leverage modifier is to insure that DCF performance remains tied to leverage levels assumed in PAA's long term plan as of the grant date (the "Grant Date Plan").

2. *Vesting and Payout*. As soon as administratively feasible following the close of the three-year period ending on June 30, 2024 (the "Performance Period"), the Compensation Committee shall determine and certify the DCF Payout Percentage (as defined below). The Compensation Committee shall make such determination based on a scaled payout range between 0% and 200% as provided in the table below (the specific payout percentage is referred to as the "DCF Payout Percentage") based on PAA's cumulative DCF per CUE over the Performance Period. If PAA's cumulative DCF per CUE at the end of the Performance Period is between any two of the stated amounts in the table below, the DCF Payout Percentage will be interpolated between the two levels. The DCF Payout Percentage may be adjusted upward or downward by +/- 50 percentage points (the "Leverage Modifier") based on PAA's leverage ratio (long-term debt to adjusted EBITDA as calculated pursuant to PAA's senior unsecured revolving credit facility) as of June 30, 2024 compared to the leverage ratio assumed in the Grant Date Plan. The Leverage Modifier will be applied as follows:

   (i) if the leverage ratio as of June 30, 2024 is between 3.1x and 3.4x, there will be no adjustment to the DCF Payout Percentage;

   (ii) if the leverage ratio as of June 30, 2024 is higher than 3.4x, the DCF Payout Percentage will be reduced by 50 gross percentage points; and

   (iii) if the leverage ratio as of June 30, 2024 is lower than 3.1x, the DCF Payout Percentage will be increased by 50 gross percentage points (subject to a 200% cap).

Cumulative DCF Per CUE Over the Performance Period	**DCF Payout Percentage**
$6.75 (112.5% of target)	200%
$6.5625	175%
$6.3750	150%
$6.1875	125%
$6.00 (target)	100%
$5.85	75%
$5.70	50%
$5.55	25%
$5.40 (90% of target)	0%

Note: Both the cumulative DCF per CUE targets set forth in the table above and the leverage ratios referenced above are based on the Grant Date Plan, excluding the earnings and leverage impacts of potential asset sales (other than asset sales under contract as of the grant date). Accordingly, when calculating the DCF Payout Percentage, the following adjustments will be made:

(a) the cumulative DCF per CUE target for the Performance Period as set forth in the table above will be adjusted downward to account for the loss of earnings assumed in the Grant Date Plan for any divested assets, net of avoided interest expense allocable to the divested assets (calculated based on an assumption that 100% of the net sales proceeds from such divestitures are used to reduce debt); and

(b) with respect to any divested assets that were included as divestitures in the Grant Date Plan, the leverage ratio target will be adjusted to reflect the leverage impact of any such divested assets based on the assumptions originally set forth in the Grant Date Plan.

In addition, for the Leverage Modifier, the leverage ratio calculation will be adjusted up or down as appropriate to neutralize the impact on leverage of any DCF per CUE over or under performance that has already been taken into account in determining the final amount of cumulative DCF per CUE during the Performance Period (with the goal of isolating the balance sheet impact of other actions such as timing and amount of asset sales, amount of capital expenditures, etc.). The number of Tranche 3 Phantom Units vesting will be determined by multiplying your target number of Tranche 3 Phantom Units by the DCF Payout Percentage as certified by the Compensation Committee. If the resulting amount includes a fraction, it will be rounded down to the nearest whole number.

Illustrative Examples (based on an assumed target number of Tranche 3 Phantom Units of 1,000):

PAA Cumulative DCF per CUE Over the Performance Period	**Leverage Ratio as of June 30, 2024**	**DCF Payout Percentage / Number of Units Vesting (Impact of Leverage Modifier)**
$6.75	3.25x	200% / 2,000 units (no adjustment to DCF Payout Percentage)
$6.75	3.45x	150% / 1,500 units (DCF Payout Percentage reduced by 50 percentage points)
$6.75	2.95x	200% / 2,000 units (DCF Payout Percentage capped at 200%)
$6.00	3.25x	100% / 1,000 units (no adjustment to DCF Payout Percentage)
$6.00	3.45x	50% / 500 units (DCF Payout Percentage reduced by 50 percentage points)
$6.00	2.95x	150% / 1,500 units (DCF Payout Percentage increased by 50 percentage points)
$5.40	3.25x	0% / 0 units (no adjustment to DCF Payout Percentage)
$5.40	3.45x	0% / 0 units (no adjustment to DCF Payout Percentage)
$5.40	2.95x	50% / 500 units (DCF Payout Percentage increased by 50 percentage points)

2021 ANNUAL DIRECTOR GRANT

August 19, 2021

«FirstName» «LastName»
«Address»
«City», «State» «Zip»

Re: Grant of Phantom Class A Shares

Dear «Salutation»:

I am pleased to inform you that you have been granted 11,900 Phantom Class A Shares as of the above date pursuant to the Plains GP Holdings, L.P. Long-Term Incentive Plan (the “Plan”). In tandem with each Phantom Class A Share granted hereby you have been granted a distribution equivalent right (a “DER”). A DER represents the right to receive a cash payment equivalent to the amount, if any, paid in cash distributions on one Class A Share of Plains GP Holdings, L.P. (“PAGP” or the “Partnership”) to the holder of such Class A Share. The terms and conditions of this grant are as set forth below.

1. Subject to the further provisions of this Agreement, your Phantom Class A Shares shall vest (become payable in the form of one Class A Share of PAGP for each Phantom Class A Share that vests) on the August 2025 Distribution Date.

2. Subject to the further provisions of this Agreement, your DERs shall be payable in cash substantially contemporaneously with each Distribution Date.

3. Immediately after the vesting of any Phantom Class A Shares, an equal number of DERs shall expire.

4. Upon any forfeiture of Phantom Class A Shares, an equal number of DERs shall expire.

5. In the event that (i) you voluntarily terminate your service on the Board of Directors (other than for Retirement) or (ii) your service on the Board of Directors is terminated by the Board (by a majority vote of the remaining Directors) for Cause (as defined in the LLC Agreement), all unvested Phantom Class A Shares (and tandem DERs) shall be forfeited as of the date service terminates.

6. In the event your service on the Board of Directors is terminated (i) because of your death or disability (as determined in good faith by the Board), (ii) due to your Retirement, or (iii) for any reason other than as described in clauses (i) and (ii) of paragraph 5 above, all unvested Phantom Class A Shares shall immediately become nonforfeitable and shall vest in full as of the next following Distribution Date. Upon such payment, the tandem DERs associated with the Phantom Class A Shares that are vesting shall expire.

7. For the avoidance of doubt, to the extent the expiration of a DER relates to the vesting of a Phantom Class A Share on a Distribution Date, the intent is for the DER to be paid with respect to such Distribution Date before the DER expires.

As used herein, (i) “Company” refers to PAA GP Holdings LLC, (ii) “Distribution Date” means the day in February, May, August or November in any year (as context dictates) that is 45 days after the end of a calendar quarter (or, if not a business day, the closest previous business day), (iii) “Board of Directors” or “Board” means the Board of Directors of the Company, and (iv) “Retirement” means you have provided the Chairman of the Board of the Company with written notice indicating that (a) you have retired (or will retire within the next sixty days) from full-time employment and from service as a director of the Company, and (b) excluding director positions held by you at such time, you do not intend to serve as a director of any other public company.

Terms used herein that are not defined herein shall have the meanings set forth in the Plan or, if not defined in the Plan, in the Second Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P., as amended (the “Partnership Agreement”) or the Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC, as amended (the “LLC Agreement”). By signing below, you agree that the Phantom Class A Shares and DERs granted hereunder are governed by the terms of the Plan. Copies of the Plan, the Partnership Agreement and the LLC Agreement are available upon request.

Please designate in the space provided below a beneficiary to receive benefits payable under this a grant in the event of your death. In addition, please execute and return a copy of this grant letter to me and retain a copy for your records.

PLAINS GP HOLDINGS, L.P.

By: PAA GP HOLDINGS LLC

By: ____________________________________
Name: Richard McGee
Title: Executive Vice President

____
«FirstName» «LastName»

No. of Phantom Class A Shares: 11,900

Dated: __________

Beneficiary Designation

Primary Beneficiary Name	Relationship	Percent (Must total 100%)
Secondary Beneficiary Name	Relationship	Percent (Must total 100%)

EXHIBIT 31.1

CERTIFICATION

I, Willie Chiang, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2021

/s/ Willie Chiang
Willie Chiang
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Al Swanson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 8, 2021

/s/ Al Swanson

Al Swanson
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Willie Chiang, Chief Executive Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended September 30, 2021 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Willie Chiang
Name: Willie Chiang
Date: November 8, 2021

EXHIBIT 32.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350**

I, Al Swanson, Chief Financial Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended September 30, 2021 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Al Swanson

Name: Al Swanson
Date: November 8, 2021