

**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, 2023

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

(State or other jurisdiction of incorporation or organization)

76-0582150

(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

Non-accelerated filer

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 31, 2023, there were 700,992,512 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, 2023	December 31, 2022
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 260	\$ 401
Trade accounts receivable and other receivables, net	4,253	3,907
Inventory	617	729
Other current assets	201	318
Total current assets	<u>5,331</u>	<u>5,355</u>
PROPERTY AND EQUIPMENT		
Accumulated depreciation	20,853	20,020
Property and equipment, net	<u>(5,264)</u>	<u>(4,770)</u>
	15,589	15,250
OTHER ASSETS		
Investments in unconsolidated entities	2,830	3,084
Intangible assets, net	1,969	2,145
Linefill	957	961
Long-term operating lease right-of-use assets, net	315	349
Long-term inventory	327	284
Other long-term assets, net	417	464
Total assets	<u>\$ 27,735</u>	<u>\$ 27,892</u>
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Trade accounts payable	\$ 4,145	\$ 4,044
Short-term debt	710	1,159
Other current liabilities	751	688
Total current liabilities	<u>5,606</u>	<u>5,891</u>
LONG-TERM LIABILITIES		
Senior notes, net	7,241	7,237
Other long-term debt, net	55	50
Long-term operating lease liabilities	280	308
Other long-term liabilities and deferred credits	1,002	1,081
Total long-term liabilities	<u>8,578</u>	<u>8,676</u>
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
PARTNERS' CAPITAL		
Series A preferred unitholders (71,090,468 and 71,090,468 units outstanding, respectively)	1,508	1,505
Series B preferred unitholders (800,000 and 800,000 units outstanding, respectively)	787	787
Common unitholders (700,992,512 and 698,354,498 units outstanding, respectively)	7,990	7,765
Total partners' capital excluding noncontrolling interests	<u>10,285</u>	<u>10,057</u>
Noncontrolling interests	3,266	3,268
Total partners' capital	<u>13,551</u>	<u>13,325</u>
Total liabilities and partners' capital	<u>\$ 27,735</u>	<u>\$ 27,892</u>

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,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(unaudited)		(unaudited)	
REVENUES				
Product sales revenues	\$ 11,581	\$ 14,001	\$ 34,726	\$ 43,390
Services revenues	490	335	1,288	1,000
Total revenues	12,071	14,336	36,014	44,390
COSTS AND EXPENSES				
Purchases and related costs	11,106	13,071	32,972	41,181
Field operating costs	372	318	1,062	971
General and administrative expenses	92	83	263	243
Depreciation and amortization	260	238	776	711
(Gains)/losses on asset sales and asset impairments, net	7	—	(144)	(46)
Total costs and expenses	11,837	13,710	34,929	43,060
OPERATING INCOME	234	626	1,085	1,330
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	99	105	277	306
Gain on investment in unconsolidated entities	29	1	28	1
Interest expense (net of capitalized interest of \$3, \$1, \$8, and \$3, respectively)	(97)	(99)	(290)	(305)
Other income/(expense), net	—	(82)	85	(237)
INCOME BEFORE TAX	265	551	1,185	1,095
Current income tax expense	(22)	(12)	(104)	(60)
Deferred income tax (expense)/benefit	36	(97)	22	(117)
NET INCOME	279	442	1,103	918
Net income attributable to noncontrolling interests	(76)	(58)	(185)	(144)
NET INCOME ATTRIBUTABLE TO PAA	\$ 203	\$ 384	\$ 918	\$ 774
NET INCOME PER COMMON UNIT (NOTE 3):				
Net income allocated to common unitholders — Basic and Diluted	\$ 140	\$ 333	\$ 728	\$ 621
Basic and diluted weighted average common units outstanding	700	698	699	702
Basic and diluted net income per common unit	\$ 0.20	\$ 0.48	\$ 1.04	\$ 0.89

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,	
	2023	2022	2023	2022
	(unaudited)		(unaudited)	
Net income	\$ 279	\$ 442	\$ 1,103	\$ 918
Other comprehensive income/(loss)	(35)	(173)	50	(150)
Comprehensive income	244	269	1,153	768
Comprehensive income attributable to noncontrolling interests	(76)	(58)	(185)	(144)
Comprehensive income attributable to PAA	\$ 168	\$ 211	\$ 968	\$ 624

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, 2022	\$ (107)	\$ (846)	\$ (1)	\$ (954)
Reclassification adjustments	8	—	—	8
Unrealized gain on hedges	40	—	—	40
Currency translation adjustments	—	2	—	2
Total period activity	48	2	—	50
Balance at September 30, 2023	\$ (59)	\$ (844)	\$ (1)	\$ (904)

	Derivative Instruments	Translation Adjustments	Other	Total
	(unaudited)			
Balance at December 31, 2021	\$ (208)	\$ (642)	\$ (3)	\$ (853)
Reclassification adjustments	5	—	—	5
Unrealized gain on hedges	88	—	—	88
Currency translation adjustments	—	(241)	—	(241)
Other	—	—	(2)	(2)
Total period activity	93	(241)	(2)	(150)
Balance at September 30, 2022	\$ (115)	\$ (883)	\$ (5)	\$ (1,003)

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,	
	2023	2022
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	\$ 1,103	\$ 918
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	776	711
Gains on asset sales and asset impairments, net	(144)	(46)
Deferred income tax expense/(benefit)	(22)	117
Gains on sales of linefill	(2)	(35)
(Gain)/loss on foreign currency revaluation	(4)	42
Settlement of terminated interest rate hedging instruments (Note 7)	80	42
Change in fair value of Preferred Distribution Rate Reset Option (Note 7)	(58)	196
Equity earnings in unconsolidated entities	(277)	(306)
Distributions on earnings from unconsolidated entities	351	344
Gain on investment in unconsolidated entities	(28)	(1)
Other	55	42
Changes in assets and liabilities, net of acquisitions	(114)	50
Net cash provided by operating activities	<u>1,716</u>	<u>2,074</u>
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(289)	(68)
Investments in unconsolidated entities	(28)	(3)
Additions to property, equipment and other	(404)	(312)
Cash paid for purchases of linefill	(19)	(69)
Proceeds from sales of assets	286	58
Cash received from sales of linefill	9	72
Other investing activities	1	31
Net cash used in investing activities	<u>(444)</u>	<u>(291)</u>
CASH FLOWS FROM FINANCING ACTIVITIES		
Repayments of senior notes (Note 5)	(400)	(750)
Repurchase of common units	—	(74)
Distributions paid to Series A preferred unitholders (Note 6)	(123)	(112)
Distributions paid to Series B preferred unitholders (Note 6)	(55)	(25)
Distributions paid to common unitholders (Note 6)	(560)	(432)
Distributions paid to noncontrolling interests (Note 6)	(237)	(194)
Contributions from noncontrolling interests	53	26
Other financing activities	(87)	(47)
Net cash used in financing activities	<u>(1,409)</u>	<u>(1,608)</u>
Effect of translation adjustment	(4)	(5)
Net increase/(decrease) in cash and cash equivalents and restricted cash	(141)	170
Cash and cash equivalents and restricted cash, beginning of period	401	453
Cash and cash equivalents and restricted cash, end of period	<u>\$ 260</u>	<u>\$ 623</u>
Cash paid for:		
Interest, net of amounts capitalized	\$ 247	\$ 268
Income taxes, net of amounts refunded	\$ 28	\$ 85

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			Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Preferred Unitholders		Common Unitholders			
	Series A	Series B				
	(unaudited)					
Balance at December 31, 2022	\$ 1,505	\$ 787	\$ 7,765	\$ 10,057	\$ 3,268	\$ 13,325
Net income	129	56	733	918	185	1,103
Distributions (Note 6)	(129)	(56)	(560)	(745)	(237)	(982)
Other comprehensive income	—	—	50	50	—	50
Contributions from noncontrolling interests	—	—	—	—	53	53
Other	3	—	2	5	(3)	2
Balance at September 30, 2023	\$ 1,508	\$ 787	\$ 7,990	\$ 10,285	\$ 3,266	\$ 13,551

	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, 2023	\$ 1,507	\$ 787	\$ 8,085	\$ 10,379	\$ 3,223	\$ 13,602
Net income	44	19	140	203	76	279
Distributions (Note 6)	(44)	(19)	(187)	(250)	(86)	(336)
Other comprehensive loss	—	—	(35)	(35)	—	(35)
Contributions from noncontrolling interests	—	—	—	—	53	53
Other	1	—	(13)	(12)	—	(12)
Balance at September 30, 2023	\$ 1,508	\$ 787	\$ 7,990	\$ 10,285	\$ 3,266	\$ 13,551

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, 2021	\$ 1,505	\$ 787	\$ 7,680	\$ 9,972	\$ 2,838	\$ 12,810
Net income	112	37	625	774	144	918
Distributions	(112)	(37)	(432)	(581)	(194)	(775)
Other comprehensive loss	—	—	(150)	(150)	—	(150)
Repurchase of common units	—	—	(74)	(74)	—	(74)
Contributions from noncontrolling interests	—	—	—	—	26	26
Other	—	—	3	3	(15)	(12)
Balance at September 30, 2022	\$ 1,505	\$ 787	\$ 7,652	\$ 9,944	\$ 2,799	\$ 12,743

	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, 2022	\$ 1,505	\$ 787	\$ 7,639	\$ 9,931	\$ 2,788	\$ 12,719
Net income	37	12	335	384	58	442
Distributions	(37)	(12)	(152)	(201)	(73)	(274)
Other comprehensive loss	—	—	(173)	(173)	—	(173)
Contributions from noncontrolling interests	—	—	—	—	26	26
Other	—	—	3	3	—	3
Balance at September 30, 2022	\$ 1,505	\$ 787	\$ 7,652	\$ 9,944	\$ 2,799	\$ 12,743

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE UNAUDITED 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 and conducted through two operating segments: Crude Oil and NGL. See Note 10 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, 2023, AAP also owned a limited partner interest in us through its ownership of approximately 239.0 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, 2023, owned an approximate 82% 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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MMbbls	=	Million barrels
NGL	=	Natural gas liquids, including ethane, propane and butane
NYMEX	=	New York Mercantile Exchange
SEC	=	United States Securities and Exchange Commission
SOFR	=	Secured Overnight Financing Rate
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 2022 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. The condensed consolidated balance sheet data as of December 31, 2022 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, 2023 should not be taken as indicative of results to be expected for the entire year. 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 balances and transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation.

Subsequent Events

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Recent Accounting Pronouncements

Except as discussed below and in our 2022 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, 2023 that are of significance or potential significance to us.

In August 2023, the FASB issued ASU 2023-05, *Business Combinations—Joint Venture Formations (Subtopic 805-60): Recognition and Initial Measurement*, which requires a newly-formed joint venture to apply a new basis of accounting to its contributed net assets, resulting in the joint venture initially measuring its contributed net assets at fair value on the formation date. This guidance is effective prospectively for all joint ventures with a formation date on or after January 1, 2025, with early adoption permitted. We will adopt this guidance for joint venture formations on January 1, 2025.

Note 2—Revenues and Accounts Receivable

Revenue Recognition

We disaggregate our revenues by segment and type of activity. See Note 3 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for additional information regarding our types of revenues and policies for revenue recognition.

Revenues from Contracts with Customers. The following tables present our revenues from contracts with customers disaggregated by segment and type of activity (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Crude Oil segment revenues from contracts with customers				
Sales	\$ 11,525	\$ 13,362	\$ 33,843	\$ 41,796
Transportation	333	185	839	515
Terminalling, Storage and Other	99	90	284	270
Total Crude Oil segment revenues from contracts with customers	\$ 11,957	\$ 13,637	\$ 34,966	\$ 42,581

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
NGL segment revenues from contracts with customers				
Sales	\$ 283	\$ 417	\$ 1,168	\$ 1,761
Transportation	7	7	23	23
Terminalling, Storage and Other	23	21	74	66
Total NGL segment revenues from contracts with customers	\$ 313	\$ 445	\$ 1,265	\$ 1,850

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 to total revenues of reportable segments and total revenues as disclosed in our Condensed Consolidated Statements of Operations (in millions):

Three Months Ended September 30, 2023	Crude Oil	NGL	Total
Revenues from contracts with customers	\$ 11,957	\$ 313	\$ 12,270
Other revenues	(23)	(71)	(94)
Total revenues of reportable segments	\$ 11,934	\$ 242	\$ 12,176
Intersegment revenues elimination			(105)
Total revenues			\$ 12,071

Three Months Ended September 30, 2022	Crude Oil	NGL	Total
Revenues from contracts with customers	\$ 13,637	\$ 445	\$ 14,082
Other revenues	38	325	363
Total revenues of reportable segments	\$ 13,675	\$ 770	\$ 14,445
Intersegment revenues elimination			(109)
Total revenues			\$ 14,336

Nine Months Ended September 30, 2023	Crude Oil	NGL	Total
Revenues from contracts with customers	\$ 34,966	\$ 1,265	\$ 36,231
Other items in revenues	22	47	69
Total revenues of reportable segments	\$ 34,988	\$ 1,312	\$ 36,300
Intersegment revenues			(286)
Total revenues			\$ 36,014

Nine Months Ended September 30, 2022	Crude Oil	NGL	Total
Revenues from contracts with customers	\$ 42,581	\$ 1,850	\$ 44,431
Other items in revenues	113	225	338
Total revenues of reportable segments	\$ 42,694	\$ 2,075	\$ 44,769
Intersegment revenues			(379)
Total revenues			\$ 44,390

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, 2023	December 31, 2022
Billed and collected	Other current liabilities	\$ 80	\$ 104
Unbilled ⁽¹⁾	N/A	1	1
Total		\$ 81	\$ 105

⁽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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 changes in the liability balance associated with contracts with customers (in millions):

	Contract Liabilities
Balance at December 31, 2022	\$ 229
Amounts recognized as revenue	(40)
Additions	45
Balance at September 30, 2023	\$ 234

Remaining Performance Obligations. The information below includes the amount of consideration allocated to partially and wholly unsatisfied remaining performance obligations under contracts that existed 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 contracts 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, 2023 (in millions):

	Remainder of 2023	2024	2025	2026	2027	2028 and Thereafter
Pipeline revenues supported by minimum volume commitments and capacity agreements ⁽¹⁾	\$ 89	\$ 357	\$ 319	\$ 148	\$ 103	\$ 266
Terminalling, storage and other agreement revenues	69	220	137	107	95	747
Total	\$ 158	\$ 577	\$ 456	\$ 255	\$ 198	\$ 1,013

⁽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;
- Buy/sell arrangements with future committed volumes;
- Short-term contracts and those with variable consideration, due to the election of practical expedients;
- Contracts within the scope of ASC Topic 842, *Leases*; and
- Contracts within the scope of ASC Topic 815, *Derivatives and Hedging*.

Trade Accounts Receivable and Other Receivables, Net

At September 30, 2023 and December 31, 2022, 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.

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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, 2023	December 31, 2022
Trade accounts receivable arising from revenues from contracts with customers	\$ 4,449	\$ 4,141
Other trade accounts receivables and other receivables ⁽¹⁾	8,278	7,216
Impact due to contractual rights of offset with counterparties	(8,474)	(7,450)
Trade accounts receivable and other receivables, net	<u>\$ 4,253</u>	<u>\$ 3,907</u>

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

Note 3—Net Income Per Common Unit

We calculate basic and diluted net income per common unit by dividing net income attributable to PAA (after deducting amounts allocated to the preferred unitholders and participating securities) by the basic and diluted weighted average number of common units outstanding during the period.

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. See Note 12 and Note 18 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for a discussion of our Series A preferred units and 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 per common unit for each of the three and nine months ended September 30, 2023 and 2022 as the effect was antidilutive. 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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Basic and Diluted Net Income per Common Unit				
Net income attributable to PAA	\$ 203	\$ 384	\$ 918	\$ 774
Distributions to Series A preferred unitholders	(44)	(37)	(129)	(112)
Distributions to Series B preferred unitholders	(19)	(12)	(56)	(37)
Amounts allocated to participating securities	(1)	(2)	(8)	(4)
Other	1	—	3	—
Net income allocated to common unitholders ⁽¹⁾	<u>\$ 140</u>	<u>\$ 333</u>	<u>\$ 728</u>	<u>\$ 621</u>
Basic and diluted weighted average common units outstanding	700	698	699	702
Basic and diluted net income per common unit	<u>\$ 0.20</u>	<u>\$ 0.48</u>	<u>\$ 1.04</u>	<u>\$ 0.89</u>

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- (1) We calculate net income 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 4—Inventory, Linefill and Long-term Inventory

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

	September 30, 2023				December 31, 2022			
	Volumes	Unit of Measure	Carrying Value	Price/Unit ⁽¹⁾	Volumes	Unit of Measure	Carrying Value	Price/Unit ⁽¹⁾
Inventory								
Crude oil	4,491	barrels	\$ 366	\$ 81.50	6,713	barrels	\$ 452	\$ 67.33
NGL	9,107	barrels	242	\$ 26.57	7,285	barrels	270	\$ 37.06
Other	N/A		9	N/A	N/A		7	N/A
Inventory subtotal			<u>617</u>				<u>729</u>	
Linefill								
Crude oil	15,255	barrels	891	\$ 58.41	15,480	barrels	906	\$ 58.53
NGL	2,195	barrels	66	\$ 30.07	1,876	barrels	55	\$ 29.32
Linefill subtotal			<u>957</u>				<u>961</u>	
Long-term inventory								
Crude oil	3,254	barrels	290	\$ 89.12	3,102	barrels	246	\$ 79.30
NGL	1,326	barrels	37	\$ 27.90	1,066	barrels	38	\$ 35.65
Long-term inventory subtotal			<u>327</u>				<u>284</u>	
Total			<u>\$ 1,901</u>				<u>\$ 1,974</u>	

- (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.

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Note 5—Debt

Debt consisted of the following (in millions):

	September 30, 2023	December 31, 2022
SHORT-TERM DEBT		
Senior notes:		
2.85% senior notes due January 2023	\$ —	\$ 400
3.85% senior notes due October 2023	700	700
Other	10	59
Total short-term debt	710	1,159
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of \$42 and \$46, respectively	7,241	7,237
Other	55	50
Total long-term debt	7,296	7,287
Total debt ⁽¹⁾	\$ 8,006	\$ 8,446

⁽¹⁾ Our fixed-rate senior notes had a face value of approximately \$8.0 billion and \$8.4 billion as of September 30, 2023 and December 31, 2022, respectively. We estimated the aggregate fair value of these notes as of September 30, 2023 and December 31, 2022 to be approximately \$7.1 billion and \$7.6 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. The fair value estimate for our senior notes is based upon observable market data and is classified in Level 2 of the fair value hierarchy.

Credit Facilities

In August 2023, we extended the maturity dates of our senior secured hedged inventory facility and senior unsecured revolving credit facility by one year to August 2026 and August 2028, respectively, for each extending lender. The maturity date with respect to the non-extending lender under our senior unsecured revolving credit facility (which represents a commitment of approximately \$64 million out of total commitments of \$1.35 billion from all lenders) remains August 2027.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the nine months ended September 30, 2023 and 2022 were approximately \$4.9 billion and \$19.3 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately \$4.9 billion and \$19.3 billion for the nine months ended September 30, 2023 and 2022, 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.

On January 31, 2023, we redeemed our 2.85%, \$400 million senior notes due January 2023. On October 16, 2023, we redeemed our 3.85%, \$700 million senior notes due October 2023.

Letters of Credit

In connection with our merchant activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil and NGL. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At September 30, 2023 and December 31, 2022, we had outstanding letters of credit of \$147 million and \$102 million, respectively.

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Note 6—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, 2022	71,090,468	800,000	698,354,498
Issuances of common units under equity-indexed compensation plans	—	—	35,508
Outstanding at March 31, 2023 and June 30, 2023	71,090,468	800,000	698,390,006
Issuances of common units under equity-indexed compensation plans	—	—	2,602,506
Outstanding at September 30, 2023	71,090,468	800,000	700,992,512
	Limited Partners		
	Series A Preferred Units	Series B Preferred Units	Common Units
Outstanding at December 31, 2021	71,090,468	800,000	704,991,540
Repurchase and cancellation of common units under the Common Equity Repurchase Program	—	—	(2,375,299)
Issuances of common units under equity-indexed compensation plans	—	—	51,937
Outstanding at March 31, 2022	71,090,468	800,000	702,668,178
Repurchase and cancellation of common units under the Common Equity Repurchase Program	—	—	(4,876,062)
Issuances of common units under equity-indexed compensation plans	—	—	147,830
Outstanding at June 30, 2022	71,090,468	800,000	697,939,946
Issuances of common units under equity-indexed compensation plans	—	—	392,739
Outstanding at September 30, 2022	71,090,468	800,000	698,332,685

Distributions

Series A Preferred Unit Distributions. After the fifth anniversary of the January 28, 2016 issuance date of our Series A preferred units, the holders of our Series A preferred units, acting by majority vote, had the option to make a one-time election to reset the Series A preferred unit distribution rate to equal the then applicable rate of ten-year U.S. Treasury Securities plus 5.85% (the “Preferred Distribution Rate Reset Option”). In January 2023, the Series A preferred unitholders elected the Preferred Distribution Rate Reset Option which resulted in an increase in the quarterly distribution rate to approximately \$0.615 per unit. This new distribution rate was effective on January 31, 2023. The quarterly distribution paid in May 2023 reflected a pro-rated amount of approximately \$0.585 per unit. The following table details distributions to our Series A preferred unitholders paid during or pertaining to the first nine months of 2023 (in millions, except per unit data):

Distribution Payment Date	Series A Preferred Unitholders	
	Cash Distribution	Distribution per Unit
November 14, 2023 ⁽¹⁾	\$ 44	\$ 0.615
August 14, 2023	\$ 44	\$ 0.615
May 15, 2023	\$ 42	\$ 0.585
February 14, 2023	\$ 37	\$ 0.525

⁽¹⁾ Payable to unitholders of record at the close of business on October 31, 2023 for the period from July 1, 2023 through September 30, 2023. At September 30, 2023, such amount was accrued as distributions payable in “Other current liabilities” on our Condensed Consolidated Balance Sheet.

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Series B Preferred Unit Distributions. Distributions on the Series B preferred units accumulate and are payable quarterly in arrears on the 15th day of February, May, August and November. From November 15, 2022 through August 14, 2023, distributions on the Series B preferred units accumulated for each distribution period at a percentage of the liquidation preference of \$1,000 per unit equal to the applicable three-month LIBOR plus a spread of 4.11% per annum. Beginning August 15, 2023, distributions on the Series B preferred units accumulate based on the applicable three-month SOFR, plus a credit spread adjustment of 0.26121%, plus 4.11% per annum. See Note 12 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for additional information regarding our Series B preferred unit distributions. The following table details distributions paid or to be paid to our Series B preferred unitholders (in millions, except per unit data):

Distribution Payment Date	Series B Preferred Unitholders	
	Cash Distribution	Distribution per Unit
November 15, 2023 ⁽¹⁾	\$ 20	\$ 24.88
August 15, 2023	\$ 19	\$ 24.10
May 15, 2023	\$ 18	\$ 22.18
February 15, 2023	\$ 18	\$ 22.27

⁽¹⁾ Payable to unitholders of record at the close of business on November 1, 2023 for the period from August 15, 2023 through November 14, 2023. At September 30, 2023, approximately \$10 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 2023 (in millions, except per unit data):

Distribution Payment Date	Distributions				Total Cash Distribution	Cash Distribution per Common Unit
	Common Unitholders		Public	AAP		
	Public	AAP				
November 14, 2023 ⁽¹⁾	\$ 125	\$ 62	\$ 187	\$ 0.2675		
August 14, 2023	\$ 123	\$ 64	\$ 187	\$ 0.2675		
May 15, 2023	\$ 122	\$ 65	\$ 187	\$ 0.2675		
February 14, 2023	\$ 122	\$ 65	\$ 187	\$ 0.2675		

⁽¹⁾ Payable to unitholders of record at the close of business on October 31, 2023 for the period from July 1, 2023 through September 30, 2023.

Noncontrolling Interests in Subsidiaries

As of September 30, 2023, noncontrolling interests in our subsidiaries consisted of (i) a 35% interest in Plains Oryx Permian Basin LLC (the "Permian JV"), (ii) a 30% interest in Cactus II Pipeline LLC ("Cactus II") and (iii) a 33% interest in Red River Pipeline Company LLC ("Red River").

Distributions to Noncontrolling Interests

The following table details distributions paid to noncontrolling interests during the periods presented (in millions):

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Permian JV	\$ 67	\$ 68	\$ 178	\$ 179
Cactus II ⁽¹⁾	14	—	43	—
Red River	5	5	16	15
	<u>\$ 86</u>	<u>\$ 73</u>	<u>\$ 237</u>	<u>\$ 194</u>

⁽¹⁾ In November 2022, we acquired an additional interest in Cactus II which, combined with changes in the governance of this entity, resulted in our obtaining control of the entity. Subsequent to this transaction, we reflect Cactus II as a consolidated subsidiary. See Note 7 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for additional information on the Cactus II transaction.

Note 7—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 commodity price risk and interest 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 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 or interest 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, 2023 and December 31, 2022, 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 are described below.

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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, 2023, net derivative positions related to these activities included:

- A net long position of 6.3 million barrels associated with our crude oil purchases, which was unwound ratably during October 2023 to match monthly average pricing.
- A net short time spread position of 6.7 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through January 2025.
- A net crude oil basis spread position of 1.7 million barrels at multiple locations through November 2024. These derivatives allow us to lock in grade and location basis differentials.
- A net short position of 15.1 million barrels through December 2024 related to anticipated net sales of crude oil and NGL inventory.

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, 2023:

	Notional Volume (Short)/Long	Remaining Tenor
Natural gas purchases	82.1 Bcf	December 2025
Propane sales	(14.2) MMbbls	December 2024
Butane sales	(4.1) MMbbls	December 2024
Condensate sales	(3.8) MMbbls	December 2025
Fuel gas requirements ⁽¹⁾	3.5 Bcf	December 2024
Power supply requirements ⁽¹⁾	2.2 TWh	December 2030

⁽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,	
	2023	2022	2023	2022
Product sales revenues	\$ (142)	\$ 320	\$ (24)	\$ 183
Field operating costs	(17)	23	(30)	44
Net gain/(loss) from commodity derivative activity	\$ (159)	\$ 343	\$ (54)	\$ 227

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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, 2023	December 31, 2022
Initial margin	\$ 84	\$ 93
Variation margin returned	(58)	(236)
Letters of credit	(25)	(25)
Net broker receivable/(payable)	<u>\$ 1</u>	<u>\$ (168)</u>

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, 2023				December 31, 2022			
	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	\$ 134	\$ (55)	\$ 1	\$ 80	\$ 300	\$ (71)	\$ (168)	\$ 61
Other long-term assets, net	6	(1)	—	5	9	(5)	—	4
Derivative Liabilities								
Other current liabilities	5	(39)	—	(34)	2	(13)	—	(11)
Other long-term liabilities and deferred credits	2	(15)	—	(13)	—	—	—	—
Total	<u>\$ 147</u>	<u>\$ (110)</u>	<u>\$ 1</u>	<u>\$ 38</u>	<u>\$ 311</u>	<u>\$ (89)</u>	<u>\$ (168)</u>	<u>\$ 54</u>

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, 2023 (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	6/15/2026	3.09%	Cash flow hedge
Anticipated interest payments	4 forward starting swaps (30-year)	\$ 100	6/14/2024	0.74%	Cash flow hedge

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During the nine months ended September 30, 2023, we terminated \$200 million of notional interest hedging instruments previously expected to terminate in June 2023 for proceeds of \$80 million, of which \$73 million was recorded in AOCI. As of September 30, 2023, there was a net loss of \$59 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 2056 as the underlying hedged transactions impact earnings. A portion of these amounts is based on market prices as of September 30, 2023; 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,	
	2023	2022	2023	2022
Interest rate derivatives, net	\$ 38	\$ 16	\$ 40	\$ 88

At September 30, 2023, the net fair value of our interest rate hedges, which were included in “Other current assets” and “Other long-term assets, net” on our Condensed Consolidated Balance Sheet, totaled \$57 million and \$23 million, respectively. At December 31, 2022, the net fair value of these hedges totaled \$75 million and \$45 million, which were included in “Other current assets” and “Other long-term assets, net”, respectively.

Preferred Distribution Rate Reset Option

In January 2023, we received notice that the Series A preferred unitholders elected the Preferred Distribution Rate Reset Option. Prior to this election, the Preferred Distribution Rate Reset Option was accounted for as an embedded derivative. 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 embedded derivative was required to be bifurcated from the related host contract, our partnership agreement, and recorded at fair value on our Condensed Consolidated Balance Sheet. 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 Sheet, totaled \$189 million at December 31, 2022. The Preferred Distribution Rate Reset Option was settled when we received notice that the Series A preferred unitholders elected the Preferred Distribution Rate Reset Option. The fair value of the Preferred Distribution Rate Reset Option on the settlement date was \$131 million. The Preferred Distribution Rate Reset Option embedded derivative was not designated in a hedging relationship for accounting purposes and corresponding changes in fair value were recognized in “Other income/(expense), net” in our Condensed Consolidated Statements of Operations. For the three months ended September 30, 2022, we recognized a loss of \$49 million. For the nine months ended September 30, 2023 and 2022, we recognized a gain of \$58 million and a net loss of \$196 million, respectively. See Note 6 for additional information regarding 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):

Recurring Fair Value Measures ⁽¹⁾	Fair Value as of September 30, 2023				Fair Value as of December 31, 2022			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	\$ (1)	\$ 38	\$ —	\$ 37	\$ (7)	\$ 229	\$ —	\$ 222
Interest rate derivatives	—	80	—	80	—	120	—	120
Preferred Distribution Rate Reset Option	—	—	—	—	—	—	(189)	(189)
Total net derivative asset/(liability)	\$ (1)	\$ 118	\$ —	\$ 117	\$ (7)	\$ 349	\$ (189)	\$ 153

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

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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 and interest rate 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 the Preferred Distribution Rate Reset Option contained in our partnership agreement which was classified as an embedded derivative. As discussed above, the Preferred Distribution Rate Reset Option was settled on January 31, 2023. The fair value of the Preferred Distribution Rate Reset Option was based on a Monte Carlo valuation model that estimated the fair value of the Series A preferred units with and without the Preferred Distribution Rate Reset Option. This model relied on assumptions for forecasts for the ten-year U.S. Treasury rate, our common unit price, and default probabilities which impacted timing estimates as to when the option would be exercised.

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,	
	2023	2022	2023	2022
Beginning Balance	\$ —	\$ (147)	\$ (189)	\$ (2)
Net gains/(losses) for the period included in earnings	—	(49)	58	(196)
Settlements	—	—	131	2
Ending Balance	\$ —	\$ (196)	\$ —	\$ (196)
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	\$ —	\$ (49)	\$ —	\$ (196)

Note 8—Related Party Transactions

See Note 17 to our Consolidated Financial Statements included in Part IV of our 2022 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.

Promissory Notes with our General Partner

In March 2023, PAGP issued an unsecured promissory note to us with a face value of CAD\$500 million (“related party note receivable”). Concurrently, we assigned PAGP our interest in an existing unsecured promissory note for the same face value amount due from a consolidated subsidiary (“related party note payable”). Both notes are due April 2027 and bear interest at a rate of 8.25% per annum, payable semi-annually.

Accrued and unpaid interest receivable/payable was \$3 million as of September 30, 2023. Interest income/expense on the related party notes totaled \$8 million and \$18 million for the three and nine months ended September 30, 2023, respectively.

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As of September 30, 2023, our outstanding related party note receivable and related party note payable balances were as follows (in millions):

	September 30, 2023
Related party note receivable ⁽¹⁾	\$ 369
Related party note payable ⁽¹⁾	\$ 369

⁽¹⁾ We have elected to present our related party notes with the same counterparty on a net basis on our Condensed Consolidated Balance Sheet because there is a legal right to offset and we intend to offset with the counterparty.

Transactions with Other Related Parties

During the three and nine months ended September 30, 2023 and 2022, we recognized sales and transportation revenues, purchased petroleum products and utilized transportation and storage services from 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,	
	2023	2022	2023	2022
Revenues from related parties	\$ 13	\$ 11	\$ 37	\$ 33
Purchases and related costs from related parties	\$ 103	\$ 90	\$ 302	\$ 274

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

	September 30, 2023	December 31, 2022
Trade accounts receivable and other receivables, net from related parties ⁽¹⁾	\$ 85	\$ 45
Trade accounts payable to related parties ^{(1) (2)}	\$ 70	\$ 79

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

⁽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.

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Note 9—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

We currently own or lease, and in the past have owned and leased, properties where hazardous liquids, including hydrocarbons, are or have been handled. These properties and the hazardous liquids or associated wastes disposed thereon may be subject to the U.S. federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, and the U.S. federal Resource Conservation and Recovery Act, as amended, as well as state and Canadian federal and provincial laws and regulations. Under such laws and regulations, we could be required to remove or remediate hazardous liquids or associated wastes (including wastes disposed of or released by prior owners or operators) and to clean up contaminated property (including contaminated groundwater). Assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified or insured.

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. We also may discover environmental impacts from past releases that were previously unidentified. 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.

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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, 2023, our estimated undiscounted reserve for environmental liabilities (excluding liabilities related to the Line 901 incident, as discussed further below) totaled \$57 million, of which \$12 million was classified as short-term and \$45 million was classified as long-term. At December 31, 2022, our estimated undiscounted reserve for environmental liabilities (excluding liabilities related to the Line 901 incident) totaled \$55 million, of which \$10 million was classified as short-term and \$45 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 both September 30, 2023 and December 31, 2022, we had recorded receivables (excluding receivables related to the Line 901 incident) totaling \$4 million 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.

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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, which resolved all regulatory claims related to the incident, 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. On October 13, 2022, Plains sold Line 901 and the Sisquoc to Pentland portion of Line 903 to Pacific Pipeline Company, an indirect wholly owned subsidiary of Exxon Mobil Corporation. As required by the terms of the Consent Decree, such purchaser assumed responsibility for compliance with the Consent Decree as it relates to the future ownership and operation of Line 901 and the Sisquoc to Pentland portion of Line 903.

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. In September 2021, the Superior Court 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 and certain separately represented claimants have appealed the Court’s rulings.

We also received several 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. In addition to the other lawsuits disclosed herein, the following lawsuits remain: (i) a lawsuit filed in the United States District Court for the Central District of California that was remanded to the California Superior Court in Santa Barbara County 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; (ii) a lawsuit filed by the California State Land Commission in California Superior Court in Santa Barbara County, seeking lost royalties following the shut-down of Line 901, as well as costs related to the decommissioning of such platform, and (iii) lawsuits filed in California Superior Court in Santa Barbara County, by 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 remaining lawsuits and believe we have strong defenses.

Furthermore, 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.

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Additionally, a class action lawsuit was filed against us in United States District Court for the Central District of California in which the class 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. The purchaser of Line 901 and the Sisquoc to Pentland portion of Line 903 has assumed liability for these claims with respect to its interest in such acquired pipelines and Plains has been dismissed from this portion of the lawsuit. In the same proceeding, a small subset of plaintiffs are also claiming damages to compensate them for the alleged diminished value of their properties due to the stigma of the oil spill. We are vigorously defending against these stigma damages claims.

In a separate class action lawsuit that was pending in United States District Court for the Central District of California, the plaintiffs claimed 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. In 2022, in order to fully and finally resolve all claims and litigation for both classes, we reached an agreement to settle this case in exchange for a payment of \$230 million (the "Class Action Settlement"). The Class Action Settlement was formally approved by the trial court on September 20, 2022, and we made the \$230 million settlement payment on October 27, 2022 and the lawsuit was subsequently dismissed.

Plains formally submitted claims for reimbursement of the Class Action Settlement to our insurance carriers on November 7, 2022. To date, we have received payment of approximately \$3.6 million from one insurer, which represents the final payment obligation of such insurer and brings the total amount collected from all insurers under such program to \$275 million of the \$500 million policy limits as of September 30, 2023. Insurers responsible for \$185 million of the remaining \$225 million of coverage formally communicated a denial of coverage for the Class Action Settlement generally alleging that some or all damages encompassed by the Class Action Settlement are not covered by their policies and that all or some portion of the \$275 million for which Plains has already received insurance reimbursement does not properly exhaust the underlying policies that paid those sums. The insurer responsible for the final \$40 million of coverage under such insurance program has not yet responded to our reimbursement demand. We have initiated arbitration proceedings against the insurers responsible for \$175 million of coverage and intend to vigorously pursue recovery from our insurers of all amounts for which we have claimed reimbursement. We believe that our claim for reimbursement from our insurers of the Class Action Settlement payment is strong and that our ultimate recovery of such amounts is probable. Our belief is based on: (i) our analysis of the terms of the underlying insurance policies as applied to the facts and circumstances that comprise our claim for reimbursement, (ii) our experience with the cost submissions and timely collection of claims for the \$275 million collected to date for this incident under the same insurance program as the denied claims, including from some of the same insurers who are now denying claims, (iii) our extensive legal review and assessment of the insurer's claimed basis for denial of coverage, which review and assessment includes the advice of external legal counsel experienced in these type of matters and solidly supports our belief that our insurers are required to provide coverage based on the terms of the policies and the nature of our claims, and (iv) the financial strength of the insurance carriers as determined by an independent credit ratings agency. Various factors could impact the timing and amount of recovery of our insurance receivable, including future developments that adversely impact our assessment of the strength of our coverage claims, the outcome of any dispute resolution proceedings with respect to our coverage claims and the extent to which insurers may become insolvent in the future. An unfavorable resolution could have a material impact on our results of operations.

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In connection with the foregoing, including the Class Action Settlement, we have made adjustments to our total estimated Line 901 costs and the portion of such costs that we believe are probable of recovery from insurance carriers, net of deductibles. Effective as of September 30, 2023, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately \$740 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, certain third party claims settlements (including the Class Action Settlement), and estimated costs associated with our remaining Line 901 lawsuits and claims as described above, as well as estimates for certain legal fees and statutory interest where applicable. 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.

During the nine months ended September 30, 2022, we recognized costs, net of amounts probable of recovery from insurance carriers, of \$85 million. We did not recognize any such costs during the nine months ended September 30, 2023. As of September 30, 2023, we had a remaining undiscounted gross liability of approximately \$94 million related to the Line 901 incident, which aggregate amount is reflected in “Current liabilities” on our Condensed Consolidated Balance Sheet. As discussed above, we maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such liabilities. As of September 30, 2023, our incurred costs for the Line 901 incident have exceeded our insurance coverage limit of \$500 million related to our 2015 insurance program applicable to the Line 901 incident by \$240 million. Through September 30, 2023, we had collected, subject to customary reservations, approximately \$280 million out of the \$505 million of release costs that we believe are probable of recovery from insurance carriers (including the 2015 insurance program and our directors and officers (D&O) insurance policies), net of deductibles. Therefore, as of September 30, 2023, we have recognized a long-term receivable of approximately \$225 million for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles and amounts already collected. We anticipate that the process to enforce our coverage claims with respect to the Class Action Settlement will take time and, accordingly, have recognized such amount as a long-term asset in “Other assets” 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 legal, professional and regulatory costs during future periods. Taking into account the costs that we have included in our total estimate of costs for the Line 901 incident and considering what we regard as very strong defenses to the claims made in our remaining Line 901 lawsuits, we do not believe the ultimate resolution of such remaining lawsuits will have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

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Other Litigation Matters. On July 19, 2022 Hartree Natural Gas Storage, LLC (“Hartree”) filed a lawsuit under seal in the Superior Court for the State of Delaware asserting claims against PAA Natural Gas Storage, L.P. and PAA arising out of a Membership Interest Purchase Agreement relating to the 2021 sale of the Pine Prairie Energy Center natural gas storage facility to Hartree. We believe the claims are without merit and that the outcome of the lawsuit will not have a material adverse effect on our financial condition, results of operations or cash flows. We intend to vigorously defend against the claims asserted in this lawsuit.

Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident, natural disaster, terrorist attack, cyber event or other event. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. We maintain various types and varying levels of insurance coverage to cover our operations and properties, and we self-insure certain risks, including gradual pollution, cybersecurity and named windstorms. To the extent we do maintain insurance coverage, such insurance does not cover every potential risk that might occur, associated with operating pipelines, terminals and other facilities and equipment, including the potential loss of significant revenues and cash flows.

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

Note 10—Segment Information

We manage our operations through two operating segments, which are also our reportable segments: Crude Oil and NGL. See Note 20 to our Consolidated Financial Statements included in Part IV of our 2022 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.

The measure of Segment Adjusted EBITDA forms the basis of our internal financial reporting and is the primary performance measure used by our CODM in assessing performance and allocating resources among our operating segments. We define Segment Adjusted EBITDA as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses, plus (d) our proportionate share of the depreciation and amortization expense (including write-downs related to cancelled projects and impairments) of unconsolidated entities, further adjusted (e) 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 either related to investing activities (such as the purchase of linefill) or purchases of long-term inventory, 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 and (f) to exclude the portion of all preceding items that is attributable to noncontrolling interests (“Adjusted EBITDA attributable to noncontrolling interests”).

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

	Crude Oil	NGL	Intersegment Revenues Elimination	Total
Three Months Ended September 30, 2023				
Revenues ⁽¹⁾ :				
Product sales	\$ 11,481	\$ 201	\$ (101)	\$ 11,581
Services	453	41	(4)	490
Total revenues	<u>\$ 11,934</u>	<u>\$ 242</u>	<u>\$ (105)</u>	<u>\$ 12,071</u>
Equity earnings in unconsolidated entities	<u>\$ 99</u>	<u>\$ —</u>		<u>\$ 99</u>
Segment Adjusted EBITDA	<u>\$ 553</u>	<u>\$ 99</u>		<u>\$ 652</u>
Maintenance capital expenditures	<u>\$ 39</u>	<u>\$ 21</u>		<u>\$ 60</u>
Three Months Ended September 30, 2022				
Revenues ⁽¹⁾ :				
Product sales	\$ 13,367	\$ 735	\$ (101)	\$ 14,001
Services	308	35	(8)	335
Total revenues	<u>\$ 13,675</u>	<u>\$ 770</u>	<u>\$ (109)</u>	<u>\$ 14,336</u>
Equity earnings in unconsolidated entities	<u>\$ 105</u>	<u>\$ —</u>		<u>\$ 105</u>
Segment Adjusted EBITDA	<u>\$ 536</u>	<u>\$ 86</u>		<u>\$ 622</u>
Maintenance capital expenditures	<u>\$ 35</u>	<u>\$ 41</u>		<u>\$ 76</u>
Nine Months Ended September 30, 2023				
Revenues ⁽¹⁾ :				
Product sales	\$ 33,815	\$ 1,182	\$ (271)	\$ 34,726
Services	1,173	130	(15)	1,288
Total revenues	<u>\$ 34,988</u>	<u>\$ 1,312</u>	<u>\$ (286)</u>	<u>\$ 36,014</u>
Equity earnings in unconsolidated entities	<u>\$ 277</u>	<u>\$ —</u>		<u>\$ 277</u>
Segment Adjusted EBITDA	<u>\$ 1,600</u>	<u>\$ 352</u>		<u>\$ 1,952</u>
Maintenance capital expenditures	<u>\$ 107</u>	<u>\$ 62</u>		<u>\$ 169</u>
Nine Months Ended September 30, 2022				
Revenues ⁽¹⁾ :				
Product sales	\$ 41,802	\$ 1,943	\$ (355)	\$ 43,390
Services	892	132	(24)	1,000
Total revenues	<u>\$ 42,694</u>	<u>\$ 2,075</u>	<u>\$ (379)</u>	<u>\$ 44,390</u>
Equity earnings in unconsolidated entities	<u>\$ 306</u>	<u>\$ —</u>		<u>\$ 306</u>
Segment Adjusted EBITDA	<u>\$ 1,482</u>	<u>\$ 367</u>		<u>\$ 1,849</u>
Maintenance capital expenditures	<u>\$ 80</u>	<u>\$ 66</u>		<u>\$ 146</u>

⁽¹⁾ Segment revenues include intersegment amounts that are eliminated in Purchases and related costs. 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.

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Segment Adjusted EBITDA Reconciliation

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Segment Adjusted EBITDA	\$ 652	\$ 622	\$ 1,952	\$ 1,849
Adjustments: ⁽¹⁾				
Depreciation and amortization of unconsolidated entities ⁽²⁾	(21)	(21)	(67)	(58)
Derivative activities and inventory valuation adjustments ⁽³⁾	(196)	376	(201)	363
Long-term inventory costing adjustments ⁽⁴⁾	58	(83)	27	22
Deficiencies under minimum volume commitments, net ⁽⁵⁾	(14)	(16)	(5)	(31)
Equity-indexed compensation expense ⁽⁶⁾	(10)	(9)	(28)	(24)
Foreign currency revaluation ⁽⁷⁾	15	2	—	1
Line 901 incident ⁽⁸⁾	—	—	—	(85)
Transaction-related expenses ⁽⁹⁾	(1)	—	(1)	—
Adjusted EBITDA attributable to noncontrolling interests ⁽¹⁰⁾	117	98	317	264
Depreciation and amortization	(260)	(238)	(776)	(711)
Gains/(losses) on asset sales and asset impairments, net	(7)	—	144	46
Gain on investment in unconsolidated entities	29	1	28	1
Interest expense, net	(97)	(99)	(290)	(305)
Other income/(expense), net	—	(82)	85	(237)
Income before tax	265	551	1,185	1,095
Income tax (expense)/benefit	14	(109)	(82)	(177)
Net income	279	442	1,103	918
Net income attributable to noncontrolling interests	(76)	(58)	(185)	(144)
Net income attributable to PAA	\$ 203	\$ 384	\$ 918	\$ 774

⁽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 and impairments) 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 (i) investing activities, such as the purchase of linefill, and (ii) purchases of long-term inventory. We also exclude the impact of corresponding inventory valuation adjustments, as applicable.

⁽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.

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- (5) We, and certain of our equity method investees, 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 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 or equity earnings, 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 be settled in cash is not excluded in determining Segment Adjusted EBITDA. See Note 18 to our Consolidated Financial Statements included in Part IV of our 2022 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.
- (8) Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance. See Note 9 for additional information regarding the Line 901 incident.
- (9) Includes expenses associated with the Rattler Permian Transaction. See Note 11 for information regarding this transaction.
- (10) Reflects amounts attributable to noncontrolling interests in the Permian JV, Cactus II and Red River.

Note 11— Acquisitions and Divestitures

Acquisitions

Rattler Permian Transaction. In the third quarter of 2023, we completed the “Rattler Permian Transaction” where the Permian JV acquired the remaining 43% interest in OMOG JV Holdings LLC (“OMOG”) and certain gathering assets in the Southern Delaware basin from Rattler Midstream Operating LLC (“Rattler”). The transaction had an aggregate purchase price of \$294 million (\$191 million net to our 65% interest in the Permian JV). As a result of the transaction, the Permian JV now owns 100% of OMOG and its subsidiaries and such entities are reflected as consolidated subsidiaries in our Condensed Consolidated Financial Statements. Prior to this transaction, the Permian JV's 57% interest in OMOG was accounted for as an equity method investment.

The acquisition was accounted for as a business combination using the acquisition method of accounting. In accordance with applicable accounting guidance, the fair value of the assets acquired and liabilities assumed following the acquisition was utilized as the consideration transferred for the purchase price allocation.

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As a result of us obtaining control over OMOG, the Permian JV's previously-held 57% interest in OMOG was remeasured to its fair value of \$239 million based upon a valuation of the acquired business, as of the date of acquisition. We considered multiple factors in determining the fair value of the previously-held equity method investment, including, (i) the price negotiated with Rattler for its 43% interest in OMOG and (ii) a discounted cash flow approach. The discounted cash flow approach utilized a discount rate of 10.85%, based on the estimate of the risk that a theoretical market participant would assign to the business. The remeasurement of the Permian JV's investment in OMOG to fair value resulted in a gain of \$29 million. This gain has been recognized in the line item "Gain on investment in unconsolidated entities" on our Condensed Consolidated Statement of Operations.

The determination of the fair value of the assets and liabilities assumed was estimated in accordance with applicable accounting guidance. The analysis was performed based on estimates that are reflective of market participant assumptions. While the purchase price for the Rattler Permian Transaction was \$294 million, all of the OMOG assets and liabilities were remeasured to fair value and therefore, the fair value of the assets and liabilities that are now consolidated on the balance sheet as a result of this transaction is \$532 million. The following table reflects our preliminary determination of the fair value of the Rattler Permian Transaction assets and liabilities (in millions):

Identifiable Assets Acquired and Liabilities Assumed:	Estimated Useful Lives (in years)	Recognized Amount
Property and equipment	3-30	\$ 483
Intangible assets	10	35
Working capital and other assets and liabilities	N/A	14
		\$ 532

The fair value of the tangible assets is a Level 3 measurement in the fair value hierarchy and was determined using the cost approach based on costs incurred on similar recent construction projects. The fair value of the intangible assets is also a Level 3 measurement in the fair value hierarchy and was determined by applying a discounted cash flow approach. Such approach utilized discount rates varying from 21.1% to 22.9%, based on our estimate of the risk that a theoretical market participant would assign to the respective intangible assets. The projection of future crude oil volumes transported and the estimated tariff rates for transportation were also key assumptions in the valuation of the intangible assets. Projected future volumes and estimated tariff rates were based on current contracts in place with assumptions for forecasted rate increases and contract renewals.

The fair value of intangible assets is comprised of customer relationships that will be amortized over their useful lives, which have a remaining weighted average life of approximately 10 years. The value assigned to such intangible assets will be amortized to earnings under the declining balance method of amortization. Amortization expense was approximately \$2 million during the three months ended September 30, 2023, and the future amortization expense for the fourth quarter of 2023 through 2027 is estimated as follows (in millions):

Remainder of 2023	\$	2
2024	\$	8
2025	\$	10
2026	\$	4
2027	\$	3

Pro forma financial information assuming the acquisition had occurred as of the beginning of the calendar year prior to the year of the acquisition, as well as the revenues and earnings generated during the period since the acquisition date, were not material for disclosure purposes.

Northern Delaware Basin Gathering Acquisition. On November 1, 2023, we acquired a crude oil gathering system in the Northern Delaware Basin from a subsidiary of LM Energy Partners for approximately \$135 million (approximately \$88 million net to our 65% interest in the Permian JV), subject to certain adjustments.

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Divestitures

Keyera Fort Saskatchewan Divestiture. In February 2023, we sold our 21% non-operated/undivided joint interest in the Keyera Fort Saskatchewan facility for approximately \$270 million. As of December 31, 2022, we classified the assets related to this transaction (primarily “Property and equipment” in our NGL segment), valued at the lower of the carrying amount or fair value less costs to sell, of approximately \$130 million as assets held for sale, which is reflected in “Other current assets” on our Condensed Consolidated Balance Sheet. Upon the sale of this facility, we recognized a gain of approximately \$140 million which is included in “(Gains)/losses on asset sales and asset impairments, net” on our Condensed Consolidated Statement of Operations.

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 2022 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
- Recent Accounting Pronouncements
- 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 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.

Overview of Operating Results

During the first nine months of 2023, we recognized net income attributable to PAA of \$918 million compared to \$774 million during the first nine months of 2022. Our results include the benefit of higher tariff volumes and tariff escalations on our crude oil pipelines. In addition, the 2022 comparative period was impacted by an increase in the accrual for estimated costs associated with the Line 901 incident.

Additionally, net income for the first nine months of 2023 compared to the first nine months of 2022 includes more favorable impacts from gains on asset sales and the mark-to-market adjustment of the Preferred Distribution Rate Reset Option, partially offset by unfavorable variances related to derivative mark-to-market valuations associated with our NGL operations.

See the “Results of Operations” section below for further discussion.

Results of Operations

Consolidated Results

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

	Three Months Ended September 30,		Variance		Nine Months Ended September 30,		Variance	
	2023	2022	\$	%	2023	2022	\$	%
Product sales revenues	\$ 11,581	\$ 14,001	\$ (2,420)	(17)%	\$ 34,726	\$ 43,390	\$ (8,664)	(20)%
Services revenues	490	335	155	46 %	1,288	1,000	288	29 %
Purchases and related costs	(11,106)	(13,071)	1,965	15 %	(32,972)	(41,181)	8,209	20 %
Field operating costs	(372)	(318)	(54)	(17)%	(1,062)	(971)	(91)	(9)%
General and administrative expenses	(92)	(83)	(9)	(11)%	(263)	(243)	(20)	(8)%
Depreciation and amortization	(260)	(238)	(22)	(9)%	(776)	(711)	(65)	(9)%
Gains/(losses) on asset sales and asset impairments, net	(7)	—	(7)	N/A	144	46	98	213 %
Equity earnings in unconsolidated entities	99	105	(6)	(6)%	277	306	(29)	(9)%
Gain on investment in unconsolidated entities	29	1	28	**	28	1	27	**
Interest expense, net	(97)	(99)	2	2 %	(290)	(305)	15	5 %
Other income/(expense), net	—	(82)	82	100 %	85	(237)	322	136 %
Income tax (expense)/benefit	14	(109)	123	113 %	(82)	(177)	95	54 %
Net income	279	442	(163)	(37)%	1,103	918	185	20 %
Net income attributable to noncontrolling interests	(76)	(58)	(18)	(31)%	(185)	(144)	(41)	(28)%
Net income attributable to PAA	\$ 203	\$ 384	\$ (181)	(47)%	\$ 918	\$ 774	\$ 144	19 %
Basic and diluted net income per common unit	\$ 0.20	\$ 0.48	\$ (0.28)	**	\$ 1.04	\$ 0.89	\$ 0.15	**
Basic and diluted weighted average common units outstanding	700	698	2	**	699	702	(3)	**

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

Revenues and Purchases

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

A majority of our sales and purchases are indexed to WTI. The following table presents the range of NYMEX WTI benchmark prices of crude oil (in dollars per barrel):

	NYMEX WTI Crude Oil Price		
	Low	High	Average
Three Months Ended September 30, 2023	\$ 70	\$ 94	\$ 82
Three Months Ended September 30, 2022	\$ 77	\$ 108	\$ 91
Nine Months Ended September 30, 2023	\$ 67	\$ 94	\$ 77
Nine Months Ended September 30, 2022	\$ 76	\$ 124	\$ 98

Product sales revenues and purchases decreased for the three and nine months ended September 30, 2023 compared to the same periods in 2022 primarily due to lower commodity prices in the 2023 periods.

Revenues from services increased for the three and nine months ended September 30, 2023 compared to the same periods in 2022 primarily due to higher volumes and tariff escalations in the 2023 periods, as well as the impact of acquisitions.

See further discussion of our net revenues (revenues less purchases and related costs) in the “—Analysis of Operating Segments” section below.

Field Operating Costs

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

General and Administrative Expenses

The increase in general and administrative expenses for the three and nine months ended September 30, 2023 compared to the same periods in 2022 was primarily due to (i) higher information systems costs due to ongoing systems integration work and (ii) higher employee-related costs, including an increase in equity-indexed compensation expense (a portion of which is excluded in the calculation of Adjusted EBITDA and Segment Adjusted EBITDA), partially offset by (iii) lower transition costs associated with the formation of the Permian JV and (iv) the impact of exchange rate fluctuations.

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

The net gains on asset sales and asset impairments for the nine months ended September 30, 2023 was primarily comprised of a gain of approximately \$140 million related to the sale of our Keyera Fort Saskatchewan facility in the first quarter of 2023. See Note 11 to our Condensed Consolidated Financial Statements for additional discussion of this transaction.

During the first quarter of 2022, we recognized a gain of \$40 million related to the sale of land and buildings in California.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and nine months ended September 30, 2023 compared to the same periods in 2022 was largely driven by acquisitions.

Interest Expense, Net

The decrease in interest expense for the nine months ended September 30, 2023 compared to the nine months ended September 30, 2022 was primarily due to a lower weighted average debt balance during the 2023 period largely driven by the repayment of \$750 million of senior notes in March 2022 and \$400 million of senior notes in January 2023.

Other Income/(Expense), Net

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Gain/(loss) on mark-to-market adjustment of Preferred Distribution Rate Reset Option embedded derivative ⁽¹⁾	\$ —	\$ (49)	\$ 58	\$ (196)
Net gain/(loss) on foreign currency revaluation ⁽²⁾	(10)	(34)	4	(43)
Other	10	1	23	2
	<u>\$ —</u>	<u>\$ (82)</u>	<u>\$ 85</u>	<u>\$ (237)</u>

⁽¹⁾ See Note 7 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 USD to CAD exchange rate on the portion of our intercompany net investment that is not long-term in nature.

Income Tax (Expense)/Benefit

The net favorable income tax variance for the three and nine months ended September 30, 2023, compared to the same periods in 2022 was primarily a result of lower year-over-year income within our Canadian operations as impacted by fluctuations of the derivative mark-to-market valuations. This favorable variance was partially offset for the nine-month period by the tax impact of the Keyera Fort Saskatchewan divestiture in the first quarter of 2023.

Noncontrolling Interests

The increase in amounts attributable to noncontrolling interests for the three and nine months ended September 30, 2023 compared to the same periods in 2022 was primarily due to (i) the consolidation of Cactus II in November 2022 and (ii) higher income recognized by the Permian JV in the 2023 periods. See Note 7 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for additional information on the Cactus II transaction.

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 Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied distributable cash flow (“DCF”), Free Cash Flow and Free Cash Flow after Distributions.

Adjusted EBITDA is defined as earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization, including write-downs related to cancelled projects and impairments, of unconsolidated entities), gains and losses on asset sales and asset impairments and gains on and impairments of investments in unconsolidated entities, adjusted for certain selected items impacting comparability.

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Adjusted EBITDA attributable to PAA and Implied DCF are reconciled to Net Income, 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—Non-GAAP Financial Liquidity Measures” for additional information regarding Free Cash Flow and Free Cash Flow after Distributions.

Non-GAAP Financial Performance Measures

Management believes that the presentation of Adjusted EBITDA, Adjusted EBITDA attributable to PAA and Implied DCF provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations, (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions and (iii) present measures that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These non-GAAP financial performance 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 either related to investing activities (such as the purchase of linefill) or purchases of long-term inventory, 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. We also adjust for amounts billed by our equity method investees related to deficiencies under minimum volume commitments. Such amounts are presented net of applicable amounts subsequently recognized into revenue. We have defined all such items as “selected items impacting comparability.” We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

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

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

	Three Months Ended September 30,		Variance		Nine Months Ended September 30,		Variance	
	2023	2022	\$	%	2023	2022	\$	%
Net income	\$ 279	\$ 442	\$ (163)	(37)%	\$ 1,103	\$ 918	\$ 185	20 %
Interest expense, net	97	99	(2)	(2)%	290	305	(15)	(5)%
Income tax expense/(benefit)	(14)	109	(123)	(113)%	82	177	(95)	(54)%
Depreciation and amortization	260	238	22	9 %	776	711	65	9 %
(Gains)/losses on asset sales and asset impairments, net	7	—	7	N/A	(144)	(46)	(98)	(213)%
Gain on investment in unconsolidated entities	(29)	(1)	(28)	**	(28)	(1)	(27)	**
Depreciation and amortization of unconsolidated entities ⁽¹⁾	21	21	—	— %	67	58	9	16 %
Selected Items Impacting Comparability:								
Derivative activities and inventory valuation adjustments	196	(376)	572	**	201	(363)	564	**
Long-term inventory costing adjustments	(58)	83	(141)	**	(27)	(22)	(5)	**
Deficiencies under minimum volume commitments, net	14	16	(2)	**	5	31	(26)	**
Equity-indexed compensation expense	10	9	1	**	28	24	4	**
Foreign currency revaluation	(15)	(2)	(13)	**	—	(1)	1	**
Line 901 incident	—	—	—	**	—	85	(85)	**
Transaction-related expenses	1	—	1	**	1	—	1	**
Selected Items Impacting Comparability - Segment Adjusted EBITDA ⁽²⁾								
Mark-to-market adjustment of Preferred Distribution Rate Reset Option embedded derivative ⁽³⁾	—	49	(49)	**	(58)	196	(254)	**
Foreign currency revaluation ⁽⁴⁾	10	34	(24)	**	(4)	43	(47)	**
Selected Items Impacting Comparability - Adjusted EBITDA ⁽⁵⁾								
Adjusted EBITDA ⁽⁵⁾	\$ 779	\$ 721	\$ 58	8 %	\$ 2,292	\$ 2,115	\$ 177	8 %
Adjusted EBITDA attributable to noncontrolling interests ⁽⁶⁾	(117)	(98)	(19)	(19)%	(318)	(264)	(54)	(20)%
Adjusted EBITDA attributable to PAA	\$ 662	\$ 623	\$ 39	6 %	\$ 1,974	\$ 1,851	\$ 123	7 %

	Three Months Ended September 30,		Variance		Nine Months Ended September 30,		Variance	
	2023	2022	\$	%	2023	2022	\$	%
Adjusted EBITDA ⁽⁵⁾	\$ 779	\$ 721	\$ 58	8 %	\$ 2,292	\$ 2,115	\$ 177	8 %
Interest expense, net of certain non-cash items ⁽⁷⁾	(92)	(96)	4	4 %	(275)	(295)	20	7 %
Maintenance capital ⁽⁸⁾	(60)	(76)	16	21 %	(169)	(146)	(23)	(16)%
Investment capital of noncontrolling interests ⁽⁹⁾	(23)	(20)	(3)	(15)%	(63)	(50)	(13)	(26)%
Current income tax expense	(22)	(12)	(10)	(83)%	(104)	(60)	(44)	(73)%
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings ⁽¹⁰⁾	(2)	(22)	20	**	(21)	(48)	27	**
Distributions to noncontrolling interests ⁽¹¹⁾	(86)	(73)	(13)	(18)%	(237)	(194)	(43)	(22)%
Implied DCF	\$ 494	\$ 422	\$ 72	17 %	\$ 1,423	\$ 1,322	\$ 101	8 %
Preferred unit distributions ⁽¹¹⁾	(63)	(37)	(26)	(70)%	(178)	(137)	(41)	(30)%
Implied DCF Available to Common Unitholders	\$ 431	\$ 385	\$ 46	12 %	\$ 1,245	\$ 1,185	\$ 60	5 %
Common unit cash distributions ⁽¹¹⁾	(187)	(152)			(560)	(432)		
Implied DCF Excess ⁽¹²⁾	\$ 244	\$ 233			\$ 685	\$ 753		

** 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 and impairments) of unconsolidated entities when reviewing Adjusted EBITDA, similar to our consolidated assets.
- (2) For a more detailed discussion of these selected items impacting comparability, see the footnotes to the Segment Adjusted EBITDA Reconciliation table in Note 10 to our Condensed Consolidated Financial Statements.
- (3) The Preferred Distribution Rate Reset Option of our Series A preferred units was 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 7 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) Other income/(expense), net on 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.
- (6) Reflects amounts attributable to noncontrolling interests in the Permian JV, Cactus II and Red River.
- (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) Investment capital expenditures attributable to noncontrolling interests that reduce Implied DCF available to PAA common unitholders.
- (10) 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).

- (11) Cash distributions paid during the period presented.
- (12) Excess DCF is retained to establish reserves for debt repayment, future distributions, common equity repurchases, capital expenditures and other partnership purposes.

Analysis of Operating Segments

We manage our operations through two operating segments: Crude Oil and NGL. Our CODM (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Adjusted EBITDA, segment volumes and maintenance capital investment. See Note 10 to our Condensed Consolidated Financial Statements for our definition of Segment Adjusted EBITDA and a reconciliation of Segment Adjusted EBITDA to Net income attributable to PAA. See Note 20 to our Consolidated Financial Statements included in Part IV of our 2022 Annual Report on Form 10-K for our definition of maintenance capital.

Crude Oil Segment

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

Our Crude Oil segment generates revenue through a combination of tariffs, pipeline capacity agreements and other transportation fees, month-to-month and multi-year storage and terminalling agreements and the sale of gathered and bulk-purchased crude oil. Tariffs and other fees on our pipeline systems are typically based on volumes transported and vary by receipt point and delivery point. Fees for our terminalling and storage services are based on capacity leases and throughput volumes. Generally, results from our merchant activities are primarily impacted by (i) increases or decreases in our lease gathering crude oil purchases volumes and (ii) volatility in commodity prices, as well as grade and regional price differentials and time spreads. The segment results also include the direct fixed and variable field costs of operating the crude oil assets, as well as an allocation of indirect operating costs.

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

Operating Results ⁽¹⁾ (in millions)	Three Months Ended September 30,		Variance		Nine Months Ended September 30,		Variance	
	2023	2022	\$	%	2023	2022	\$	%
Revenues	\$ 11,934	\$ 13,675	\$ (1,741)	(13)%	\$ 34,988	\$ 42,694	\$ (7,706)	(18)%
Purchases and related costs	(11,069)	(12,938)	1,869	14 %	(32,499)	(40,495)	7,996	20 %
Field operating costs	(266)	(235)	(31)	(13)%	(779)	(749)	(30)	(4)%
Segment general and administrative expenses ⁽²⁾	(71)	(64)	(7)	(11)%	(203)	(186)	(17)	(9)%
Equity earnings in unconsolidated entities	99	105	(6)	(6)%	277	306	(29)	(9)%
Adjustments ⁽³⁾ :								
Depreciation and amortization of unconsolidated entities	21	21	—	**	67	58	9	**
Derivative activities and inventory valuation adjustments	76	(33)	109	**	69	(3)	72	**
Long-term inventory costing adjustments	(67)	80	(147)	**	(36)	(18)	(18)	**
Deficiencies under minimum volume commitments, net	14	16	(2)	**	5	31	(26)	**
Equity-indexed compensation expense	10	9	1	**	27	24	3	**
Foreign currency revaluation	(12)	(2)	(10)	**	—	(1)	1	**
Line 901 incident	—	—	—	**	—	85	(85)	**
Transaction-related expenses	1	—	1	**	1	—	1	**
Adjusted EBITDA attributable to noncontrolling interests	(117)	(98)	(19)	**	(317)	(264)	(53)	**
Segment Adjusted EBITDA	\$ 553	\$ 536	\$ 17	3 %	\$ 1,600	\$ 1,482	\$ 118	8 %
Maintenance capital expenditures	\$ 39	\$ 35	\$ 4	11 %	\$ 107	\$ 80	\$ 27	34 %
Average Volumes								
	Three Months Ended September 30,		Variance		Nine Months Ended September 30,		Variance	
	2023	2022	Volumes	%	2023	2022	Volumes	%
Crude oil pipeline tariff (by region) ⁽⁴⁾								
Permian Basin ⁽⁵⁾	6,114	5,698	416	7 %	6,237	5,450	787	14 %
Other ⁽⁵⁾	2,145	1,883	262	14 %	2,073	1,937	136	7 %
Total crude oil pipeline tariff	8,259	7,581	678	9 %	8,310	7,387	923	12 %
Commercial crude oil storage capacity ⁽⁵⁾⁽⁶⁾	72	72	—	— %	72	72	—	— %
Crude oil lease gathering purchases ⁽⁴⁾	1,455	1,390	65	5 %	1,430	1,373	57	4 %

** 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 10 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.
- (4) Average volumes in thousands of barrels per day calculated as the total volumes (attributable to our interest for assets owned by unconsolidated entities or through undivided joint interests) for the period divided by the number of days in the period. Volumes associated with assets acquired during the periods represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.
- (5) Includes volumes (attributable to our interest) from assets owned by unconsolidated entities.
- (6) Average monthly capacity in millions of barrels calculated as total volumes for the period divided by the number of months in the period.

Segment Adjusted EBITDA

Crude Oil Segment Adjusted EBITDA increased for the three and nine months ended September 30, 2023 compared to the same periods in 2022 primarily due to higher tariff volumes, tariff escalations and contributions from acquisitions. These items were partially offset by fewer market-based opportunities.

The following is a more detailed discussion of the significant factors impacting Segment Adjusted EBITDA for the three and nine months ended September 30, 2023 compared to the same periods in 2022.

Net Revenues and Equity Earnings. Our results were favorably impacted by (i) higher volumes across our pipeline systems, primarily driven by increased production and new well connections, (ii) tariff escalations and (iii) contributions from acquisitions. These benefits were partially offset by the impact of minimum volume commitment deficiency payments received in 2022.

Our results for the three months ended September 30, 2023 reflect fewer crude oil market-based opportunities compared to the three months ended September 30, 2022. For the full nine months of 2023 compared to 2022, more favorable results from Canadian crude oil market-based opportunities in 2023 were offset by the favorable impact to the 2022 period of the sale of excess linefill in a higher crude oil price environment.

Field Operating Costs. For the three and nine months ended September 30, 2023 compared to the same periods in 2022, we had higher expenses associated with (i) utilities costs due to a combination of higher volumes and prices and an increase in the amount of drag reducing agents used, (ii) incremental consolidated operating costs in connection with acquisitions, (iii) employee-related costs primarily resulting from higher average headcount and salaries, (iv) chemical treatment costs and (v) unrealized mark-to-market losses on power hedges for the three- and nine-month period (which impact our field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above). The unfavorable variance for the nine months ended September 30, 2023 compared to 2022 was partially offset by the recognition of additional estimated costs associated with the Line 901 incident in the first quarter of 2022 (which impact field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above).

Maintenance Capital

The increase in maintenance capital spending for the three and nine months ended September 30, 2023 compared to the same periods in 2022 was primarily due to timing of routine integrity and tank maintenance, as well as vehicle lease buyouts.

NGL Segment

Our NGL segment operations involve natural gas processing and NGL fractionation, storage, transportation and terminalling. Our NGL revenues are primarily derived from a combination of (i) providing gathering, fractionation, storage, and/or terminalling services to third-party customers for a fee, and (ii) extracting NGL mix from the gas stream processed at our Empress straddle plant facility as well as acquiring NGL mix, which is then transported, stored and fractionated into finished products and sold to customers. Our management of our commodity exposure is subject to our risk management policies and may include the use of derivative instruments to mitigate the risk of such exposure and, at times, to provide upside opportunities.

Generally, our segment results are impacted by (i) increases or decreases in our NGL sales volumes, (ii) volatility in commodity prices, the differential between the price of natural gas and the extracted NGL (“frac spread”), as well as location differentials and time spreads, and (iii) the volume of natural gas transported on third-party assets through our Empress straddle plant.

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

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

Operating Results ⁽¹⁾ (in millions)	Three Months Ended September 30,		Variance		Nine Months Ended September 30,		Variance	
	2023	2022	\$	%	2023	2022	\$	%
Revenues	\$ 242	\$ 770	\$ (528)	(69)%	\$ 1,312	\$ 2,075	\$ (763)	(37)%
Purchases and related costs	(142)	(242)	100	41 %	(759)	(1,065)	306	29 %
Field operating costs	(106)	(83)	(23)	(28)%	(283)	(222)	(61)	(27)%
Segment general and administrative expenses ⁽²⁾	(21)	(19)	(2)	(11)%	(60)	(57)	(3)	(5)%
Adjustments ⁽³⁾ :								
Derivative activities	120	(343)	463	**	132	(360)	492	**
Long-term inventory costing adjustments	9	3	6	**	9	(4)	13	**
Equity-indexed compensation expense	—	—	—	N/A	1	—	1	**
Foreign currency revaluation	(3)	—	(3)	**	—	—	—	**
Segment Adjusted EBITDA	\$ 99	\$ 86	\$ 13	15 %	\$ 352	\$ 367	\$ (15)	(4)%
Maintenance capital expenditures	\$ 21	\$ 41	\$ (20)	(49)%	\$ 62	\$ 66	\$ (4)	(6)%
Average Volumes (in thousands of barrels per day) ⁽⁴⁾								
			Volumes	%			Volumes	%
NGL fractionation	107	121	(14)	(12)%	111	131	(20)	(15)%
NGL pipeline tariff	193	182	11	6 %	178	182	(4)	(2)%
Propane and butane sales ⁽⁵⁾	44	56	(12)	(21)%	73	83	(10)	(12)%

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

- (1) Revenues and costs and expenses include intersegment amounts.
- (2) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.
- (3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 10 to our Condensed Consolidated Financial Statements for additional discussion of such adjustments.
- (4) Average daily volumes are calculated as total volumes (attributable to our interest for assets owned through undivided joint interests) for the period divided by the number of days in the period.
- (5) During the fourth quarter of 2022, we modified our sales volumes reported to include only propane and butane sales. Prior to the fourth quarter of 2022, our reported sales volumes included other NGL products, primarily ethane, that represented a significant portion of our total NGL sales volumes but did not contribute significantly to Segment Adjusted EBITDA. Sales volumes for earlier periods presented herein have been recast to include only propane and butane.

Segment Adjusted EBITDA

NGL Segment Adjusted EBITDA increased for the three months ended September 30, 2023 compared to the same period in 2022 primarily due to (i) favorable NGL basis differentials and spot opportunities, partially offset by (ii) the impact of lower propane sales volumes as a result of deferring sales due to market structure, and (iii) increased field operating costs.

These net favorable impacts were more than offset for the nine months ended September 30, 2023 compared to the same period in 2022 by (i) the impact of lower NGL sales volumes during the second quarter of 2023 as a result of turnarounds, (ii) the sale of our ownership interest in the Keyera Fort Saskatchewan facility in the first quarter of 2023, combined with (iii) further increases in field operating costs.

Significant variances in the components of Segment Adjusted EBITDA are discussed in more detail below.

Net Revenues. Net revenues include the impact of derivative activities and long-term inventory costing adjustments, which are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above. Excluding such impacts, net revenues increased for the three and nine months ended September 30, 2023 compared to the same period in 2022 primarily due to (i) favorable NGL basis differentials and spot opportunities and (ii) higher processing revenues at our Empress straddle plants resulting from a commercial agreement executed in conjunction with the increase in our Empress ownership in the fourth quarter of 2022. This was partially offset by lower propane sales volumes as a result of deferring sales due to market structure, and further for the nine month period by the impact of (i) lower NGL sales volumes during the second quarter of 2023 as a result of turnarounds, (ii) higher gains at certain of our NGL facilities in 2022, and (iii) the sale of our ownership interest in the Keyera Fort Saskatchewan facility in the first quarter of 2023.

Field Operating Costs. The increase in field operating costs for the three and nine months ended September 30, 2023 compared to the same periods in 2022 was primarily due to (i) an increase in unrealized mark-to-market losses on power hedges (which impact our field operating costs but are excluded from Segment Adjusted EBITDA and thus are reflected as an "Adjustment" in the table above), (ii) increased utilities-related costs largely as a result of higher prices, and the increase in our Empress ownership in the fourth quarter of 2022, along with (iii) higher regulatory costs. The increase in utilities-related costs was partially offset by the benefit to net revenues of operating cost recoveries realized through commercial agreements.

Maintenance Capital

The decrease in maintenance capital spending for the three and nine months ended September 30, 2023 compared to the same periods in 2022 was primarily due to a scheduled turnaround at our Empress, Alberta facility during 2022, partially offset by an increase in routine integrity activities.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities and (ii) borrowings under our credit facilities or commercial paper program. In addition, we may supplement these primary sources of liquidity with proceeds from asset sales, and in the past have utilized funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to, (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products, payment of 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 and noncontrolling interests. 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 credit facilities or commercial paper program. In addition, we generally expect to fund our long-term needs, such as those resulting from investment capital activities, acquisitions or refinancing our long-term debt, through a variety of sources, which may include any or a combination of the sources listed above.

As of September 30, 2023, although we had a working capital deficit of \$275 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, 2023
Availability under senior unsecured revolving credit facility ⁽¹⁾⁽²⁾	\$ 1,272
Availability under senior secured hedged inventory facility ⁽¹⁾⁽²⁾	1,281
Amounts outstanding under commercial paper program	—
Subtotal	2,553
Cash and cash equivalents ⁽³⁾	258
Total	\$ 2,811

⁽¹⁾ Represents availability prior to giving effect to borrowings outstanding under our commercial paper program, which reduce available capacity under our credit 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 \$78 million and \$69 million, respectively.

⁽³⁾ Excludes restricted cash of \$2 million.

In August 2023, we extended the maturity dates of our senior secured hedged inventory facility and senior unsecured revolving credit facility by one year to August 2026 and August 2028, respectively, for each extending lender. The maturity date with respect to the non-extending lender under our senior unsecured revolving credit facility (which represents a commitment of approximately \$64 million out of total commitments of \$1.35 billion from all lenders) remains August 2027.

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. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We were in compliance with the covenants contained in our credit agreements and indentures as of September 30, 2023.

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, including actions by the 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 2022 Annual Report on Form 10-K for further discussion regarding risks that may impact our liquidity and capital resources.

Non-GAAP Financial Liquidity Measures

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

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

	Nine Months Ended September 30,	
	2023	2022
Net cash provided by operating activities	\$ 1,716	\$ 2,074
Adjustments to reconcile Net cash provided by operating activities to Free Cash Flow:		
Net cash used in investing activities	(444)	(291)
Cash contributions from noncontrolling interests	53	26
Cash distributions paid to noncontrolling interests ⁽¹⁾	(237)	(194)
Free Cash Flow	\$ 1,088	\$ 1,615
Cash distributions ⁽²⁾	(738)	(569)
Free Cash Flow after Distributions	<u>\$ 350</u>	<u>\$ 1,046</u>

⁽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 2022 Annual Report on Form 10-K.

Net cash provided by operating activities for the first nine months of 2023 and 2022 was \$1.716 billion and \$2.074 billion, respectively, and primarily resulted from earnings from our operations. However, the 2023 period was impacted by net negative changes in working capital items, largely associated with higher margin balances required as part of our hedging activities during the period.

Investing Activities**Capital Expenditures**

In addition to our operating needs, we also use cash for our investment capital projects, maintenance capital activities and acquisition activities. We fund these expenditures with cash generated by operating activities, financing activities and/or proceeds from asset sales. The following table summarizes our investment and maintenance capital expenditures (in millions):

	Nine Months Ended September 30,	
	2023	2022
Investment capital ⁽¹⁾ ⁽²⁾ ⁽³⁾	\$ 285	\$ 262
Maintenance capital ⁽¹⁾ ⁽³⁾	169	146
Acquisition capital ⁽²⁾ ⁽⁴⁾	295	74
	<u>\$ 749</u>	<u>\$ 482</u>

⁽¹⁾ Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as “Investment capital”. Capital expenditures made to replace and/or refurbish 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⁾ Investment capital and maintenance capital, net to our interest, was approximately \$221 million and \$158 million, respectively, for the nine months ended September 30, 2023, and approximately \$212 million and \$140 million, respectively, for the nine months ended September 30, 2022.

⁽⁴⁾ Acquisition capital for the 2023 period primarily includes the Rattler Permian Transaction (\$191 million net to our 65% interest in the Permian JV). See Note 11 to our Condensed Consolidated Financial Statements for additional information.

2023 Investment and Maintenance Capital. Total investment capital for the year ending December 31, 2023 is projected to be approximately \$420 million (\$325 million net to our interest). Approximately half of our projected investment capital expenditures are expected to be invested in the Permian JV assets. Additionally, maintenance capital for 2023 is projected to be \$225 million (\$210 million net to our interest). We expect to fund our 2023 investment and maintenance capital expenditures primarily with retained cash flow.

Divestitures

Proceeds from the sale of assets have generally been used to fund our investment capital projects and reduce debt levels. The following table summarizes the proceeds received during the first nine months of 2023 and 2022 from sales of assets (in millions):

	Nine Months Ended September 30,	
	2023	2022
Proceeds from divestitures ⁽¹⁾	\$ 286	\$ 58

⁽¹⁾ Represents proceeds, including working capital adjustments, net of transaction costs. The proceeds from divestitures for the nine months ended September 30, 2023 are primarily from the sale of our 21% non-operated/undivided joint interest in the Keyera Fort Saskatchewan facility in February 2023. See Note 11 to our Condensed Consolidated Financial Statements for additional discussion of this transaction.

Ongoing Activities Related to Strategic Transactions

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

We typically do not announce a transaction until after we have executed a definitive agreement. In certain cases, in order to protect our business interests or for other reasons, we may defer public announcement of a transaction until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential transaction can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive agreement may be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future efforts with respect to any such transactions will be successful, and we can provide no assurance that our financial expectations with respect to such transactions will ultimately be realized. See Item 1A. “Risk Factors—Risks Related to Our Business—Acquisitions and divestitures involve risks that may adversely affect our business” included in our 2022 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 Agreements

We had no net borrowings or repayments under our credit facilities or commercial paper program during the nine months ended September 30, 2023 and 2022.

Repayment of Senior Notes

On January 31, 2023, we redeemed our 2.85%, \$400 million senior notes due January 2023. We utilized a combination of cash on hand and borrowings under our commercial paper program to repay these senior notes.

On October 16, 2023, we redeemed our 3.85%, \$700 million senior notes due October 2023. We utilized a combination of cash on hand and borrowings under our commercial paper program to repay these senior notes.

Common Equity Repurchase Program

We repurchased 7.3 million common units under the Common Equity Repurchase Program (the “Program”) during the nine months ended September 30, 2022 for a total purchase price of \$74 million, including commissions and fees. There were no repurchases under the Program during the nine months ended September 30, 2023. The remaining available capacity under the Program as of September 30, 2023 was \$198 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 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, 2023. 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, 2023.

Distributions to Our Unitholders

Series A preferred unitholders. On November 14, 2023, we will pay a quarterly cash distribution of approximately \$0.615 per unit to Series A preferred unitholders of record at the close of business on October 31, 2023 for the period from July 1, 2023 through September 30, 2023.

Series B preferred unitholders. On November 15, 2023, we will pay a quarterly cash distribution of approximately \$24.88 per unit to Series B preferred unitholders of record at the close of business on November 1, 2023 for the period from August 15, 2023 through November 14, 2023.

Common Unitholders. On November 14, 2023, we will pay a quarterly cash distribution of \$0.2675 per common unit (\$1.07 per unit on an annualized basis) to common unitholders of record at the close of business on October 31, 2023 for the period from July 1, 2023 through September 30, 2023, which is unchanged from the distribution per unit paid in August of 2023.

See Note 6 to our Condensed Consolidated Financial Statements for details of distributions paid during or pertaining to the first nine months of 2023, including distributions to our preferred unitholders.

Capital Allocation Framework Update

On November 3, 2023, we provided updates to our capital allocation framework and announced our intention to recommend to the Board of Directors a \$0.20 per unit (annualized) increase to our distribution payable to holders of our common units with respect to the fourth quarter of 2023. If approved and declared by the Board of Directors, such increased distribution would be paid in February 2024.

Distributions to Noncontrolling Interests

Distributions to noncontrolling interests represent amounts paid on interests in consolidated entities that are not owned by us. As of September 30, 2023, noncontrolling interests in our subsidiaries consisted of (i) a 35% interest in the Permian JV, (ii) a 30% interest in Cactus II and (iii) a 33% interest in Red River. See Note 6 to our Condensed Consolidated Financial Statements for details of distributions paid to noncontrolling interests during the nine months ended September 30, 2023.

Contingencies

For a discussion of contingencies that may impact us, see Note 9 to our Condensed Consolidated Financial Statements.

Commitments

Purchase Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to 11 years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

The following table includes our best estimate of the amount and timing of these payments as of September 30, 2023 (in millions):

	Remainder of 2023	2024	2025	2026	2027	2028 and Thereafter	Total
Crude oil, NGL and other purchases ⁽¹⁾	\$ 7,737	\$ 24,223	\$ 22,214	\$ 20,309	\$ 17,857	\$ 47,448	\$ 139,788

⁽¹⁾ Amounts are primarily based on estimated volumes and market prices based on average activity during September 2023. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our merchant activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil, NGL and natural gas. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product is purchased. Generally, these letters of credit are issued for periods of up to 70 days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs, derivative transactions, including hedging-related margin obligations, and construction activities. At September 30, 2023 and December 31, 2022, we had outstanding letters of credit of approximately \$147 million and \$102 million, respectively.

Recent Accounting Pronouncements

See Note 1 to our Condensed Consolidated Financial Statements.

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:

- 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, the risk of persistently high inflation and continued supply chain issues, the impact of pandemics on demand and growth, and the timing, pace and extent of economic recovery) that impact (i) demand for crude oil, drilling and production activities and therefore the demand for the midstream services we provide and (ii) commercial opportunities available to us;
- declines in global crude oil demand and crude oil prices (whether due to pandemics or other factors) or other factors that correspondingly lead to a significant reduction of North American crude oil and natural gas liquids (“NGL”) 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 the margins we can earn or the commercial opportunities that might otherwise be available to us;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil and NGL and resulting changes in pricing conditions or transportation throughput requirements;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- the effects of competition and capacity overbuild in areas where we operate, including downward pressure on rates and margins, 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;
- environmental liabilities, litigation or other events that are not covered by an indemnity, insurance or existing reserves;
- 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 impact of current and future laws, rulings, governmental regulations, executive orders, trade policies, accounting standards and statements, and related interpretations, including legislation, executive orders 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, or that negatively impact our ability to develop, operate or repair midstream assets;
- loss of key personnel and inability to attract and retain new talent;
- disruptions to futures markets for crude oil, NGL and other petroleum products, which may impair our ability to execute our commercial or hedging strategies;
- the effectiveness of our risk management activities;
- shortages or cost increases of supplies, materials or labor;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- 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;
- the availability of, and our ability to consummate, divestitures, joint ventures, acquisitions or other strategic opportunities;
- 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, supply chain issues, legal constraints (including governmental orders or guidance), or other factors or events;
- the incurrence of costs and expenses related to unexpected or unplanned capital expenditures, third-party claims or other factors;
- 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;
- 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 acquisitions, investment capital projects, working capital requirements and the repayment or refinancing of indebtedness;
- 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;
- 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 2022 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 commodity price risk and interest rate risk. We use various derivative instruments to manage such risks and, in certain circumstances, to realize incremental margin during volatile market conditions. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our exchange-cleared and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

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

- Crude oil

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

- Natural gas

We utilize natural gas derivatives to hedge commodity price risk inherent in our natural gas processing assets (natural gas purchase component of the frac spread). Additionally, we utilize natural gas derivatives to hedge anticipated operational fuel gas requirements related to our natural gas processing and NGL fractionation plants. 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 commercial activities, including the sale of the individual specification products extracted in our natural gas processing assets (sale of specification NGL products component of the frac spread), as well as other net sales of NGL inventory, held mainly at our owned NGL storage terminals. 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 7 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, 2023 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	\$ (17)	\$ (40)	\$ 41
Natural gas	(31)	\$ 17	\$ (17)
NGL and other	85	\$ (67)	\$ 67
Total fair value	<u>\$ 37</u>		

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

Debt. 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, 2023. The average interest rate on variable rate debt that was outstanding during the nine months ended September 30, 2023 was 5.6%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a net asset of \$80 million as of September 30, 2023. A 10% increase in the forward SOFR curve as of September 30, 2023 would have resulted in an increase of \$19 million to the fair value of our interest rate derivatives. A 10% decrease in the forward SOFR curve as of September 30, 2023 would have resulted in a decrease of \$19 million to the fair value of our interest rate derivatives. See Note 7 to our Condensed Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Series B Preferred Units. Distributions on the Series B preferred units accumulate and are payable quarterly in arrears on the 15th day of February, May, August and November. Beginning August 15, 2023, distributions on the Series B preferred units accumulate based on the applicable three-month SOFR, plus certain adjustments. Based upon the Series B preferred units outstanding at September 30, 2023 and the liquidation preference of \$1,000 per unit, a change of 100 basis points in interest rates would increase or decrease the annual distributions on the Series B preferred units by approximately \$8 million. See Note 6 to our Condensed Consolidated Financial Statements for additional information on the Series B preferred units.

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, 2023, 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 2023 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 9 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 2022 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, 2023, we issued 139,350 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

None.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Item 5. OTHER INFORMATION

During the quarter ended September 30, 2023, none of our directors or officers (as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934) adopted or terminated a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K).

Item 6. EXHIBITS

Exhibit No.	Description
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	— Amendment No. 3 dated August 17, 2023 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 August 21, 2023).
3.15	— 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).

- 3.16 — [Bylaws of PAA Finance Corp. \(f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.\) \(incorporated by reference to Exhibit 3.11 to our Annual Report on Form 10-K for the year ended December 31, 2006\).](#)
- 3.17 — [Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 \(incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed January 4, 2008\).](#)
- 3.18 — [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\).](#)
- 3.19 — [Second Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P. dated November 15, 2016 \(incorporated by reference to Exhibit 3.2 to PAGP's Current Report on Form 8-K filed November 21, 2016\).](#)
- 3.20 — [Amendment No. 1 dated April 6, 2020 to the Second Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P. \(incorporated by reference to Exhibit 3.1 to PAGP's Current Report on Form 8-K filed April 9, 2020\).](#)
- 3.21 — [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\).](#)
- 3.22 — [Fourth Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC dated effective as of August 19, 2021 \(incorporated by reference to Exhibit 3.21 to our Annual Report on Form 10-K for the year ended December 31, 2021\).](#)
- 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 — [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 \(incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed March 26, 2012\).](#)
- 4.5 — [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 \(incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 12, 2012\).](#)
- 4.6 — [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 \(incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 15, 2013\).](#)
- 4.7 — [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 \(incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 29, 2014\).](#)
- 4.8 — [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 \(incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 11, 2014\).](#)

4.9	—	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).
4.1	—	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).
4.11	—	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).
4.12	—	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).
4.13	—	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).
4.14	—	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).
4.15	—	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).
4.16	—	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).
4.17	—	Description of Our Securities (incorporated by reference to Exhibit 4.18 to our Annual Report on Form 10-K for the year ended December 31, 2022).
10.1* †	—	Form of LTIP Grant Letter dated August 17, 2023 (Named Executive Officers)
10.2* †	—	Form of LTIP Grant Letter dated August 17, 2023 (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.

* 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 7, 2023

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

November 7, 2023

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

November 7, 2023



2023 Regular Annual LTIP Grant
Section 16 Officers

August 17, 2023

«Name»

«Address»

Re: Grant of Phantom Units

Dear «Name»:

I am pleased to inform you that, subject to the terms hereof, you have been granted a target number of Phantom Units equal to «Amount» 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 2026 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 2026 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 2023 Distribution Date and will continue to accrue until the August 2024 Distribution Date, on which date such accrued but unpaid DERs will vest and be paid in a lump sum. Beginning on the November 2024 Distribution Date, such vested DERs will be paid quarterly until the associated Phantom Units vest or are forfeited pursuant to the terms hereof.

333 Clay Street, Suite 1600 (77002) ■ P.O. Box 4648 ■ Houston, Texas 77210-4648 ■ 713-646-4100

- b. The DERs associated with Tranches 2 and 3 will begin accruing on the November 2023 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 2023 Distribution Date. All accrued and unpaid DERs associated with Tranche 2 and Tranche 3 shall be paid on the August 2026 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 2026 Distribution Date (1,093). 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, except that in connection with a Change in Status that involves a Change of Control, the Compensation Committee shall have the discretion to adjust the payout level for any Tranche 2 or Tranche 3 Phantom Units based on the performance of the Company under the applicable performance metric taking into account such Change of Control transaction, in each case as reasonably determined by the Compensation Committee) 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”)¹;
- (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).

¹ For the avoidance of doubt, the ownership by a Person of PAGP Class A or Class B shares (or combination thereof) that represent 50% or more of the outstanding Class A and B shares of PAGP (in the aggregate) constitutes indirect ownership of 50% or more of the membership interests in PAGP GP for so long as PAGP directly owns 50% or more of such membership interests in PAGP GP.

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, as it may be amended from time to time, 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

«Name»

Target Number of Phantom Units: «Amount»

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, 2026 (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 and/or indices 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 equal to or greater than 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%
2	186%
3	171%
4	157%
5	143%
6	129%
7	114%
8	100%
9	86%
10	71%
11	57%
12	43%
13	29%
14	14%
15	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	200% / 2,000 units
#4	157% / 1,570 units

#4, but PAA's absolute TSR is less than 0%	132% / 1,320 units (TSR Payout Percentage reduced by 25 gross percentage points)
#7	114% / 1,140 units
#7, but PAA's absolute TSR is less than 0%	100% / 1,000 units (TSR Payout Percentage reduced from 114% to 100%)
#8	100% / 1,000 units (performance at Target)
#12	43% / 430 units
#15	0% / 0 units

3. PAA Peer Group (2023-2026 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
Genesis Energy LP	GEL
Crestwood Equity Partners LP	CEQP
Targa Resources Corp.	TRGP
Western Midstream Partners LP	WES
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. In all cases involving the acquisition, merger, reorganization or other material change in ownership, legal structure or business operations of any member of the PAA Peer Group before the end of the Performance Period, the Compensation Committee shall have authority to retain, remove or replace such member, as applicable, 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)

- 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").
- Vesting and Payout.** As soon as administratively feasible following the close of the three-year period ending on June 30, 2026 (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. In addition, the DCF Payout Percentage will be reduced by 25 gross percentage points (the "Leverage Modifier") if PAA's leverage ratio (long-term debt to adjusted EBITDA as calculated pursuant to PAA's senior unsecured revolving credit facility, modified to include customary adjustments deemed appropriate by the Compensation Committee (for example, a "net debt" adjustment to account for certain cash balances reflected on PAA's balance sheet as of the applicable measurement date)) as of June 30, 2026 is higher than the leverage ratio that equals the upper end of PAA's then applicable guidance range (such guidance range is 3.0x to 3.5x as of the date hereof); if PAA's leverage ratio as of June 30, 2026 is equal to or lower than the leverage ratio that equals the upper end of PAA's then applicable guidance range, there will be no adjustment to the DCF Payout Percentage.

Cumulative DCF Per CUE Over the Performance Period	DCF Payout Percentage
\$8.38125 (112.5% of target)	200%
\$8.1484375	175%
\$7.915625	150%
\$7.6828125	125%
\$7.45 (target)	100%
\$7.26375	75%
\$7.0775	50%
\$6.89125	25%
\$6.705 (90% of target)	0%

Note: Both the cumulative DCF per CUE targets set forth in the table above and the leverage ratio 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:

- 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.). In addition, the Compensation Committee shall have the ability to make adjustments to the leverage ratio calculation to the extent deemed appropriate in connection with leverage attributable to a transaction or project approved by the Company's Board of Directors. 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 and based on an assumed leverage ratio of 3.5x, which is the leverage ratio that is equal to the upper end of PAA's current guidance range of 3.0x to 3.5x):

PAA Cumulative DCF per CUE Over the Performance Period	Leverage Ratio as of June 30, 2026	DCF Payout Percentage / Number of Units Vesting (Impact of Leverage Modifier)
\$8.38125	3.5x or lower	200% / 2,000 units (no adjustment to DCF Payout Percentage)
\$8.38125	3.6x	175% / 1,750 units (DCF Payout Percentage reduced by 25 gross percentage points)
\$7.45	3.5x or lower	100% / 1,000 units (no adjustment to DCF Payout Percentage)
\$7.45	3.6x	75% / 750 units (DCF Payout Percentage reduced by 25 gross percentage points)
\$6.89125	3.5x or lower	25% / 250 units (no adjustment to DCF Payout Percentage)
\$6.89125	3.6x	0% / 0 units (DCF Payout Percentage reduced by 25 gross percentage points)
\$6.705	3.5x or lower	0% / 0 units (DCF Payout Percentage equal to zero based on DCF performance)
\$6.705	3.6x	0% / 0 units (DCF Payout Percentage equal to zero based on DCF performance)

**2023 ANNUAL DIRECTOR GRANT**

August 17, 2023

<Name>
<Address>

Re: Grant of Phantom Class A Shares

Dear <Name>:

I am pleased to inform you that you have been granted 8,050 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 2024 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.

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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 Fourth Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC (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

<Name>

No. of Phantom Class A Shares: 8,050

Dated: _____

Beneficiary Designation

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

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 7, 2023

/s/ Willie Chiang

Willie Chiang

Chief Executive Officer

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 7, 2023

/s/ Al Swanson

Al Swanson

Chief Financial Officer

**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, 2023 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 7, 2023

**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, 2023 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 7, 2023