PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 08, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2017

OR

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

Commission File Number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.
(Exact name of registrant as specified in its charter)

Delaware	76-0582150
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 646-4100
(Registrant's telephone number, including area code)

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. ý Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). ý Yes o 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 ý	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company) Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o Yes o No

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

As of July 31, 2017, there were 724,696,735 Common Units outstanding.

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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)

	June 30, 2017 (unaudited)	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$47	$47
Trade accounts receivable and other receivables, net	2,088	2,279
Inventory	936	1,343
Other current assets	457	603
Total current assets	3,528	4,272
PROPERTY AND EQUIPMENT	16,850	16,220
Accumulated depreciation	(2,528)	(2,348)
Property and equipment, net	14,322	13,872
OTHER ASSETS		
Goodwill	2,596	2,344
Investments in unconsolidated entities	2,626	2,343
Linefill and base gas	894	896
Long-term inventory	117	193
Other long-term assets, net	921	290
Total assets	$25,004	$24,210
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$2,349	$2,588
Short-term debt	1,114	1,715
Other current liabilities	294	361
Total current liabilities	3,757	4,664
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discounts and debt issuance costs	9,878	9,874
Other long-term debt	162	250
Other long-term liabilities and deferred credits	706	606
Total long-term liabilities	10,746	10,730
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS' CAPITAL		
Series A preferred unitholders (66,990,153 and 64,388,853 units outstanding, respectively)	1,507	1,508

Common unitholders (724,696,735 and 669,194,419 units outstanding, respectively)	8,937	7,251
Total partners' capital excluding noncontrolling interests	10,444	8,759
Noncontrolling interests	57	57
Total partners' capital	10,501	8,816
Total liabilities and partners' capital	$25,004	$24,210

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 June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$5,781	$4,648	$12,176	$8,467
Transportation segment revenues	161	170	299	323
Facilities segment revenues	136	132	270	270
Total revenues	6,078	4,950	12,745	9,060
COSTS AND EXPENSES				
Purchases and related costs	5,320	4,224	10,912	7,571
Field operating costs	304	303	593	603
General and administrative expenses	68	73	142	140
Depreciation and amortization	129	204	250	319
Total costs and expenses	5,821	4,804	11,897	8,633
OPERATING INCOME	257	146	848	427
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	68	40	121	87
Interest expense (net of capitalized interest of $9, $12, $15 and $26, respectively)	(127)	(114)	(256)	(227)
Other income/(expense), net	1	25	(4)	30
INCOME BEFORE TAX	199	97	709	317
Current income tax expense	(1)	(9)	(11)	(40)
Deferred income tax benefit/(expense)	(9)	14	(65)	27
NET INCOME	189	102	633	304
Net income attributable to noncontrolling interests	(1)	(1)	(1)	(2)
NET INCOME ATTRIBUTABLE TO PAA	$188	$101	$632	$302
NET INCOME/(LOSS) PER COMMON UNIT (NOTE 3):				
Net income/(loss) allocated to common unitholders — Basic	$148	$(81)	$555	$(53)
Basic weighted average common units outstanding	725	398	708	398
Basic net income/(loss) per common unit	$0.21	$(0.20)	$0.78	$(0.13)
Net income/(loss) allocated to common unitholders — Diluted	$148	$(81)	$555	$(53)
Diluted weighted average common units outstanding	727	398	710	398
Diluted net income/(loss) per common unit	$0.21	$(0.20)	$0.78	$(0.13)

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(unaudited)		(unaudited)	
Net income	$189	$102	$633	$304
Other comprehensive income/(loss)	75	(73)	111	45
Comprehensive income	264	29	744	349
Comprehensive income attributable to noncontrolling interests	(1)	(1)	(1)	(2)
Comprehensive income attributable to PAA	$263	$28	$743	$347

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, 2016	$(228)	$ (782)	$ 1	$(1,009)
Reclassification adjustments	9	—	—	9
Deferred loss on cash flow hedges	(12)	—	—	(12)
Currency translation adjustments	—	114	—	114
Total period activity	(3)	114	—	111
Balance at June 30, 2017	$(231)	$ (668)	$ 1	$(898)

	Derivative Instruments	Translation Adjustments	Total
	(unaudited)		
Balance at December 31, 2015	$(203)	$ (878)	$(1,081)
Reclassification adjustments	6	—	6
Deferred loss on cash flow hedges	(158)	—	(158)
Currency translation adjustments	—	197	197
Total period activity	(152)	197	45
Balance at June 30, 2016	$(355)	$ (681)	$(1,036)

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)

	Six Months Ended June 30,	
	2017	2016
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$633	$304
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	250	319
Equity-indexed compensation expense	22	26
Inventory valuation adjustments	35	3
Deferred income tax (benefit)/expense	65	(27)
Gain on foreign currency revaluation	(11)	(2)
Settlement of terminated interest rate hedging instruments	(29)	(50)
Change in fair value of Preferred Distribution Rate Reset Option (Note 10)	2	(25)
Equity earnings in unconsolidated entities	(121)	(87)
Distributions on earnings from unconsolidated entities	136	101
Other	14	6
Changes in assets and liabilities, net of acquisitions	465	(181)
Net cash provided by operating activities	1,461	387
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(1,281)	(85)
Investments in unconsolidated entities	(250)	(120)
Additions to property, equipment and other	(549)	(699)
Proceeds from sales of assets	389	391
Return of investment from unconsolidated entities	21	—
Other investing activities	16	(9)
Net cash used in investing activities	(1,654)	(522)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) under commercial paper program (Note 8)	25	(844)
Net borrowings/(repayments) under senior secured hedged inventory facility (Note 8)	(450)	252
Repayments of senior notes (Note 8)	(400)	—
Net proceeds from the sale of Series A preferred units	—	1,569
Net proceeds from the sale of common units (Note 9)	1,664	—
Contributions from general partner	—	33
Distributions paid to common unitholders (Note 9)	(770)	(557)
Distributions paid to general partner	—	(309)
Other financing activities	123	(6)
Net cash provided by financing activities	192	138
Effect of translation adjustment on cash	1	4
Net increase in cash and cash equivalents	—	7

Cash and cash equivalents, beginning of period	47	27
Cash and cash equivalents, end of period	$47	$34
Cash paid for:		
Interest, net of amounts capitalized	$252	$225
Income taxes, net of amounts refunded	$34	$51

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

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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
	Series A Preferred Unitholders	Common Unitholders			
	(unaudited)				
Balance at December 31, 2016	$1,508	$ 7,251	$ 8,759	$ 57	$8,816
Net income	—	632	632	1	633
Cash distributions to partners	—	(770)	(770)	(1)	(771)
Sales of common units	—	1,664	1,664	—	1,664
Acquisition of interest in Advantage Joint Venture (Note 6)	—	40	40	—	40
Other comprehensive income	—	111	111	—	111
Other	(1)	9	8	—	8
Balance at June 30, 2017	$1,507	$ 8,937	$ 10,444	$ 57	$10,501

	Limited Partners		General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
	Series A Preferred Unitholders	Common Unitholders				
	(unaudited)					
Balance at December 31, 2015	$—	$ 7,580	$ 301	$ 7,881	$ 58	$7,939
Net income	—	11	291	302	2	304
Cash distributions to partners	—	(557)	(309)	(866)	(2)	(868)
Sale of Series A preferred units	1,509	—	33	1,542	—	1,542
Other comprehensive income	—	44	1	45	—	45
Other	—	7	1	8	—	8
Balance at June 30, 2016	$1,509	$ 7,085	$ 318	$ 8,912	$ 58	$8,970

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

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

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.

We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids ("NGL"), natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 13 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 June 30, 2017, AAP also owned an approximate 36% limited partner interest in us represented by approximately 288.3 million of our common units. 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 June 30, 2017, owned, directly and indirectly, an approximate 53% 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 ("PMC").

References to the "PAGP Entities" include PAGP GP, PAGP, GP LLC, AAP and PAA GP. References to our "general partner," as the context requires, include any or all of the PAGP Entities. References to the "Plains Entities" include us, our subsidiaries and the PAGP Entities.

Simplification Transactions

On November 15, 2016, the Plains Entities closed a series of transactions and executed several organizational and ancillary documents (the "Simplification Transactions") intended to simplify our capital structure, better align the interests of our stakeholders and improve our overall credit profile. The Simplification Transactions included, among other things:

- the permanent elimination of our incentive distribution rights ("IDRs") and the economic rights associated with our 2% general partner interest in exchange for the issuance by us to AAP of 245.5 million PAA common units (including approximately 0.8 million units to be issued in the future) and the assumption by us of all of AAP's outstanding debt ($642 million);
-

the implementation of a unified governance structure pursuant to which the board of directors of GP LLC was eliminated and an expanded board of directors of PAGP GP assumed oversight responsibility over both us and PAGP;

- the provision for annual PAGP shareholder meetings beginning in 2018 for the purpose of electing certain directors with expiring terms in 2018, and the participation of our common unitholders and Series A preferred unitholders in such elections through our ownership of newly issued Class C shares in PAGP, which provide us, as the sole holder of such Class C shares, the right to vote in elections of eligible PAGP directors together with the holders of PAGP Class A and Class B shares;

- the execution by AAP of a reverse split to adjust the number of AAP Class A units ("AAP units") such that the number of outstanding AAP units (assuming the conversion of AAP Class B units (the "AAP Management Units") into AAP units) equaled the number of our common units received by AAP at the closing of the Simplification Transactions. Simultaneously, PAGP executed a reverse split to adjust the number of PAGP Class A and Class B shares outstanding

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to equal the number of AAP units it owns following AAP's reverse unit split. These reverse splits, along with the Omnibus Agreement, resulted in economic alignment between our common unitholders and PAGP's Class A shareholders, such that the number of outstanding PAGP Class A shares equals the number of AAP units owned by PAGP, which in turn equals the number of our common units held by AAP that are attributable to PAGP's interest in AAP. The Plains Entities also entered into an Omnibus Agreement, pursuant to which such one-to-one relationship will be maintained subsequent to the closing of the Simplification Transactions; and

- the creation of a right for certain holders of the AAP units to cause AAP to redeem such AAP units in exchange for an equal number of our common units held by AAP.

The Simplification Transactions were between and among consolidated subsidiaries of PAGP that are considered entities under common control. These equity transactions did not result in a change in the carrying value of the underlying assets and liabilities.

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
DERs	=	Distribution equivalent rights
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
LIBOR	=	London Interbank Offered Rate
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
NGL	=	Natural gas liquids, including ethane, propane and butane
NYMEX	=	New York Mercantile Exchange
Oxy	=	Occidental Petroleum Corporation or its subsidiaries
PLA	=	Pipeline loss allowance
SEC	=	United States Securities and Exchange Commission
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 2016 Annual Report on Form 10-K. The accompanying condensed consolidated financial statements include the accounts of PAA and all of its wholly owned subsidiaries and those entities that it controls. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We apply proportionate consolidation for pipelines and other assets in which we own undivided joint interests. The financial statements have been prepared in accordance with the instructions for interim reporting as set forth by the SEC. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. The condensed consolidated balance sheet data as of December 31, 2016 was derived from audited financial statements, but does not include all disclosures required by GAAP. The results of operations for the three and six months ended June 30, 2017 should not be taken as indicative of results to be expected for the entire year.

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

Note 2—Recent Accounting Pronouncements

Except as discussed below and in our 2016 Annual Report on Form 10-K, there have been no new accounting pronouncements that have become effective or have been issued during the six months ended June 30, 2017 that are of significance or potential significance to us.

Accounting Standards Updates Adopted During the Period

In March 2016, the FASB issued ASU 2016-09, Compensation — Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which simplified several aspects of the accounting for share-based payment
transactions, including the income tax consequences, forfeitures, classification of awards as either equity or liabilities and classification of certain related payments on the statement of cash flows. This guidance was effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We adopted the applicable provisions of the ASU on January 1, 2017 and (i) elected to account for forfeitures as they occur, utilizing the modified retrospective approach of adoption, and (ii) will classify units directly withheld for tax-withholding purposes as a financing activity on our Condensed Consolidated Statement of Cash Flows for all periods presented. Our adoption did not have a material impact on our financial position, results of operations or cash flows for the periods presented.

In January 2017, the FASB issued ASU 2017-04, Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment. The amendments within this ASU eliminate Step 2 from the goodwill impairment test, which currently requires an entity to determine goodwill impairment by calculating the implied fair value of goodwill by hypothetically assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Under the amended standard, goodwill impairment will instead be measured using Step 1 of the goodwill impairment test with goodwill impairment being equal to the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying value of goodwill. This guidance is effective for annual periods beginning after December 15, 2019, and interim periods within those annual periods, with early adoption permitted. We early adopted this ASU in the first quarter of 2017 and applied the amendments therein to our 2017 annual goodwill impairment test.

Accounting Standards Updates Issued During the Period

In January 2017, the FASB issued ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business, which improves the guidance for determining whether a transaction involves the purchase or disposal of a business or an asset. This guidance becomes effective for fiscal years and interim periods beginning after December 15, 2017, with early adoption permitted, and prospective application required. We plan to adopt this guidance on January 1, 2018 and will apply the new guidance to applicable transactions occurring after that date.

In February 2017, the FASB issued ASU 2017-05, Other Income — Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. The update includes the following clarifications: (i) nonfinancial assets within the scope of Subtopic 610-20 may include nonfinancial assets transferred within a legal entity to a counterparty, (ii) an entity should allocate consideration to each distinct asset by applying the guidance in Topic 606 on allocating the transaction price to performance obligations and (iii) requires entities to derecognize a distinct nonfinancial asset or distinct in substance nonfinancial asset in a partial sale transaction when it (1) does not have (or ceases to have) a controlling financial interest in the legal entity that holds the asset in accordance with Subtopic 810-10 and (2) transfers control of the asset in accordance with Topic 606. This guidance is effective beginning after December 15, 2017, including interim periods within those periods and must be adopted at the same time as ASC 606. We will adopt this guidance on January 1, 2018 and are currently evaluating the impact of the adoption on our financial position, results of operations and cash flows.

In May 2017, the FASB issued ASU 2017-09, Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting to provide guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. Under the new guidance, modification accounting is required only if the fair value (or calculated value or intrinsic value, if such alternative method is used), the vesting conditions, or the classification of the award (equity or liability) changes as a result of the change in terms or conditions. This guidance will become effective for

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interim and annual periods beginning after December 31, 2017, with early adoption permitted, and prospective application required. We expect to adopt this guidance on January 1, 2018, and we do not currently anticipate that our adoption will have a material impact on our financial position, results of operations and cash flows.

Other Accounting Standards Updates

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) with the underlying principle that an entity will recognize revenue to reflect amounts expected to be received in exchange for the provision of goods and services to customers upon the transfer of those goods or services. This ASU also requires additional disclosures. This ASU can be adopted either with a full retrospective approach or a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption and is effective for interim and annual periods beginning after December 15, 2017. We implemented a process to evaluate the impact of adopting this ASU on each type of revenue contract entered into with customers and our implementation team is in the process of determining appropriate changes to our business processes, systems and controls to support recognition and disclosure under the new standard. We have not identified any significant revenue recognition timing differences for types of revenue streams assessed to date; however, our evaluation is not complete. In addition, we are assessing the impact of changes to disclosures and expect an increase in disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. We will adopt this guidance on January 1, 2018, and currently anticipate that we will apply the modified retrospective approach.

Note 3—Net Income Per Common Unit

We calculate basic and diluted net income/(loss) per common unit by dividing net income attributable to PAA (after deducting amounts allocated to the preferred unitholders and participating securities, and for periods prior to the closing of the Simplification Transactions, the 2% general partner's interest and IDRs) by the basic and diluted weighted-average number of common units outstanding during the period. Participating securities include LTIP awards that have vested DERs, which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

Diluted net income/(loss) per common unit 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, (ii) our LTIP awards and (iii) common units that are issuable to AAP when certain AAP Management Units become earned. When applying the if-converted method prescribed by FASB guidance, the possible conversion of our Series A preferred units was excluded from the calculation of diluted net income/(loss) per common unit for the three and six months ended June 30, 2017 and 2016 as the effect was antidilutive. Our LTIP awards that contemplate the issuance of common units and certain AAP Management Units that contemplate the issuance of common units to AAP when such AAP Management Units become earned are considered dilutive unless (i) they become vested or earned only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that were deemed to be dilutive were 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. LTIP awards were excluded from the computation of diluted net loss per common unit for the three and six months ended June 30, 2016 as the effect was antidilutive. As none of the necessary conditions for the remaining AAP Management Units to become earned had been satisfied by June 30, 2017, no common units issuable to AAP were contemplated in the calculation of diluted net income/(loss) per common unit. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2016 Annual Report on Form 10-K for a complete discussion of our LTIP awards including specific discussion regarding DERs.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Basic Net Income per Common Unit				
Net income attributable to PAA	$188	$101	632	302
Distributions to Series A preferred units [1]	(35)	(33)	(69)	(55)
Distributions to general partner [1]	—	(155)	—	(310)
Distributions to participating securities [1]	(1)	(1)	(1)	(2)
Undistributed loss allocated to general partner [1]	—	7	—	12
Other	(4)	—	(7)	—
Net income/(loss) allocated to common unitholders	$148	$(81)	$555	$(53)
Basic weighted average common units outstanding	725	398	708	398
Basic net income/(loss) per common unit	$0.21	$(0.20)	$0.78	$(0.13)
Diluted Net Income per Common Unit				
Net income attributable to PAA	$188	$101	$632	$302
Distributions to Series A preferred units [1]	(35)	(33)	(69)	(55)
Distributions to general partner [1]	—	(155)	—	(310)
Distributions to participating securities [1]	(1)	(1)	(1)	(2)
Undistributed loss allocated to general partner [1]	—	7	—	12
Other	(4)	—	(7)	—
Net income/(loss) allocated to common unitholders	$148	$(81)	$555	$(53)
Basic weighted average common units outstanding	725	398	708	398
Effect of dilutive securities:				
LTIP units	2	—	2	—
Diluted weighted average common units outstanding	727	398	710	398
Diluted net income/(loss) per common unit	$0.21	$(0.20)	$0.78	$(0.13)

(1) We calculate net income/(loss) allocated to common unitholders based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings ("undistributed loss"), if any, are allocated to the general partner, 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. The Simplification Transactions, which closed on November 15, 2016, simplified our governance structure and permanently eliminated our IDRs and the economic rights associated with our 2% general partner interest. Therefore, beginning with the distribution pertaining to the fourth quarter of 2016, our general partner is no longer entitled to receive distributions or allocations on such interests.

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Note 4—Accounts Receivable, Net

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL and natural gas. To mitigate credit risk related to our accounts receivable, we utilize a rigorous credit review process. We closely monitor market conditions to make a determination with respect to the amount, if any, of open credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of advance cash payments, standby letters of credit or parental guarantees. As of June 30, 2017 and December 31, 2016, we had received $92 million and $89 million, respectively, of advance cash payments from third parties to mitigate credit risk. We also received $50 million and $66 million as of June 30, 2017 and December 31, 2016, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. Additionally, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Furthermore, we also enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet) for a majority of net-cash settled arrangements.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At June 30, 2017 and December 31, 2016, substantially all of our trade accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $3 million at both June 30, 2017 and December 31, 2016. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

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

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

	June 30, 2017				December 31, 2016			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]
Inventory								
Crude oil	14,854	barrels	$ 675	$45.44	23,589	barrels	$ 1,049	$44.47
NGL	11,507	barrels	245	$21.29	13,497	barrels	242	$17.93
Natural gas	316	Mcf	1	$3.16	14,540	Mcf	32	$2.20
Other	N/A		15	N/A	N/A		20	N/A
Inventory subtotal			936				1,343	
Linefill and base gas								
Crude oil	12,834	barrels	741	$57.74	12,273	barrels	710	$57.85
NGL	1,625	barrels	45	$27.69	1,660	barrels	45	$27.11
Natural gas	24,976	Mcf	108	$4.32	30,812	Mcf	141	$4.58
Linefill and base gas subtotal			894				896	
Long-term inventory								
Crude oil	1,922	barrels	77	$40.06	3,279	barrels	163	$49.71
NGL	1,863	barrels	40	$21.47	1,418	barrels	30	$21.16
Long-term inventory subtotal			117				193	

Total	$ 1,947	$ 2,432

(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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At the end of each reporting period, we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. Any resulting adjustments are a component of “Purchases and related costs” on our accompanying Condensed Consolidated Statements of Operations. We recorded a charge of $35 million during the three and six months ended June 30, 2017 primarily related to the writedown of our crude oil inventory due to a decline in prices. Substantially all of this inventory valuation adjustment was offset by the recognition of gains on derivative instruments being utilized to hedge future sales of our crude oil inventory. Such gains were recorded to “Supply and Logistics segment revenues” in our accompanying Condensed Consolidated Statements of Operations. See Note 10 for discussion of our derivative and risk management activities. We recorded an inventory valuation adjustment of $3 million during the six months ended June 30, 2016.

Note 6—Acquisitions and Dispositions

Acquisitions

The following acquisitions were accounted for using the acquisition method of accounting and the determination of the fair value of the assets and liabilities acquired has been estimated in accordance with the applicable accounting guidance.

Alpha Crude Connector Acquisition

On February 14, 2017, we acquired all of the issued and outstanding membership interests in Alpha Holding Company, LLC for cash consideration of approximately $1.217 billion, subject to working capital and other adjustments (the “ACC Acquisition”). The ACC Acquisition was initially funded through borrowings under our senior unsecured revolving credit facility. Such borrowings were subsequently repaid with proceeds from our March 2017 issuance of common units to AAP pursuant to the Omnibus Agreement and in connection with a PAGP underwritten equity offering. See Note 9 for additional information.

Upon completion of the ACC Acquisition, we became the owner of a crude oil gathering system known as “Alpha Crude Connector” (the “ACC System”) located in the Northern Delaware Basin in Southeastern New Mexico and West Texas. The ACC System comprises 515 miles of gathering and transmission lines and five market interconnects, including to our Basin Pipeline at Wink. We intend to make additional interconnects to our existing Northern Delaware Basin systems as well as additional enhancements intended to increase the ACC System capacity to approximately 350,000 barrels per day, depending on the level of volume at each delivery point. The ACC System is supported by acreage dedications covering approximately 315,000 gross acres, and include a significant acreage dedication from one of the largest producers in the region. The ACC System complements our other Permian Basin assets and enhances the services available to the producers in the Northern Delaware Basin.

The determination of the acquisition-date fair value of the assets acquired and liabilities assumed is preliminary. We expect to finalize our fair value determination in 2017. The following table reflects the preliminary fair value determination (in millions):

Identifiable assets acquired and liabilities assumed:	Estimated Useful Lives (Years)	Recognized amount
Property and equipment	3 - 70	$ 299
Intangible assets	20	646
Goodwill	N/A	271
Other assets and liabilities, net (including $4 million of cash acquired)	N/A	1
		$ 1,217

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Intangible assets are included in "Other long-term assets, net" on our Condensed Consolidated Balance Sheets. The preliminary determination of fair value to intangible assets above is comprised of five acreage dedication contracts and associated customer relationships that will be amortized over a remaining weighted average useful life of approximately 20 years. The value assigned to such intangible assets will be amortized to earnings using methods that closely resemble the pattern in which the economic benefits will be consumed. Amortization expense was approximately $4 million for the period from February 14, 2017 through June 30, 2017, and the future amortization expense is estimated as follows for the next five years (in millions):

Remainder of 2017	$6
2018	$25
2019	$34
2020	$42
2021	$48

Goodwill is an intangible asset representing the future economic benefits expected to be derived from other assets acquired that are not individually identified and separately recognized. The goodwill arising from the ACC Acquisition, which is tax deductible, represents the anticipated opportunities to generate future cash flows from undedicated acreage and the synergies created between the ACC System and our existing assets. The assets acquired in the ACC Acquisition, as well as the associated goodwill, are primarily included in our Transportation segment.

During the three and six months ended June 30, 2017, we incurred approximately $1 million and $6 million of acquisition-related costs associated with the ACC Acquisition. Such costs are reflected as a component of general and administrative expenses in our Condensed Consolidated Statements of Operations.

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

Other Acquisitions

In February 2017, we acquired a propane marine terminal for cash consideration of approximately $41 million. The assets acquired are included in our Facilities segment. We did not recognize any goodwill related to this acquisition.

Investment Acquisition

On April 3, 2017, we and an affiliate of Noble Midstream Partners LP ("Noble") completed the acquisition of Advantage Pipeline, L.L.C. ("Advantage") for a purchase price of $133 million through a newly formed 50/50 joint venture (the "Advantage Joint Venture"). For our 50% share ($66.5 million), we contributed approximately 1.3 million common units with a value of approximately $40 million and approximately $26 million in cash. We account for our interest in the Advantage Joint Venture under the equity method of accounting.

Advantage owns a 70-mile, 16-inch crude oil pipeline located in the southern Delaware Basin (the "Advantage Pipeline"). Noble will serve as operator and will construct a pipeline to deliver crude oil to the Advantage Pipeline from its central gathering facility in the southern Delaware Basin. We will construct a pipeline to connect our Wolfbone Ranch facility to the Advantage Pipeline near Highway 285 in Reeves County, Texas. The connections are estimated to be completed in 2017. The Advantage Pipeline is contractually supported by a third-party acreage dedication and a volume commitment from our wholly-owned marketing subsidiary.

Dispositions, Divestitures and Assets Held for Sale

During the six months ended June 30, 2017, we sold certain non-core assets for proceeds of approximately $389 million. These sales primarily included (i) our Bluewater natural gas storage facility located in Michigan, (ii) a non-core pipeline segment located in the Midwestern United States and (iii) a 40% undivided interest in a segment of our Red River Pipeline extending from Cushing, Oklahoma to the Hewitt Station near Ardmore, Oklahoma (the “Hewitt Segment”) for our net book value. We retained a 60% undivided interest in the Hewitt Segment and a 100% interest in the remaining portion of the Red River Pipeline that extends from Ardmore to Longview, Texas.

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We recognized a net gain of $36 million during the six months ended June 30, 2017 related to the sale of the non-core pipeline segment, including the write-off of a portion of the remaining book value. In addition, during the six months ended June 30, 2017, we recognized a loss of $35 million related to assets that were classified as held for sale prior to the closing of the transactions. Such gains and losses are included in "Depreciation and amortization" on our Condensed Consolidated Statements of Operations.

As of June 30, 2017, we classified approximately $275 million of Facilities segment assets, primarily property and equipment, as held for sale on our Condensed Consolidated Balance Sheet (in "Other current assets") related to definitive agreements to sell such assets. We expect these transactions to close during 2017.

During the third quarter of 2017, we entered into a definitive agreement to sell our interests in certain non-core pipelines in the Rocky Mountains for proceeds of approximately $250 million.

Note 7—Goodwill

Goodwill by segment and changes in goodwill are reflected in the following table (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Balance at December 31, 2016	$ 806	$ 1,034	$ 504	$ 2,344
Acquisitions [1]	271	—	—	271
Foreign currency translation adjustments	8	4	2	14
Dispositions and reclassifications to assets held for sale	—	(33)	—	(33)
Balance at June 30, 2017	$ 1,085	$ 1,005	$ 506	$ 2,596

(1) Goodwill is recorded at the acquisition date based on a preliminary fair value determination. This preliminary goodwill balance may be adjusted when the fair value determination is finalized.

We completed our goodwill impairment test as of June 30, 2017 using a qualitative assessment. We determined that it was more likely than not that the fair value of each reporting unit was greater than its respective book value; therefore, additional impairment testing was not necessary and goodwill was not considered impaired.

Note 8—Debt

Debt consisted of the following (in millions):

	June 30, 2017	December 31, 2016
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 2.0% and 1.6%, respectively [1]	$ 677	$ 563
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 2.3% and 1.8%, respectively [1]	300	750
Senior notes:		
6.13% senior notes due January 2017	—	400
Other	137	2
Total short-term debt [2]	1,114	1,715
LONG-TERM DEBT		
Senior notes, net of unamortized discounts and debt issuance costs of $72 and $76, respectively [3]	9,878	9,874
Commercial paper notes, bearing a weighted-average interest rate of 2.0% and 1.6%, respectively [3]	159	247

Other	3	3
Total long-term debt	10,040	10,124
Total debt [4]	$ 11,154	$ 11,839

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(1) We classified these commercial paper notes and credit facility borrowings as short-term as of June 30, 2017 and December 31, 2016, as these notes and borrowings were primarily designated as working capital borrowings, were required to be repaid within one year and were primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

(2) As of June 30, 2017 and December 31, 2016, balance includes borrowings of $12 million and $410 million, respectively, for cash margin deposits with NYMEX and ICE, which are associated with financial derivatives used for hedging purposes.

(3) As of June 30, 2017, we have classified our $600 million, 6.50% senior notes due May 2018 as long-term and as of June 30, 2017 and December 31, 2016, we have classified a portion of our commercial paper notes as long-term based on our ability and intent to refinance such amounts on a long-term basis.

(4) Our fixed-rate senior notes (including current maturities) had a face value of approximately $9.9 billion and $10.3 billion as of June 30, 2017 and December 31, 2016, respectively. We estimated the aggregate fair value of these notes as of June 30, 2017 and December 31, 2016 to be approximately $10.1 billion and $10.4 billion, respectively. Our fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near the end of the reporting period. We estimate that the carrying value of outstanding borrowings under our credit facilities and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities and commercial paper program are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

Borrowings and Repayments

Total borrowings under our credit facilities and commercial paper program for the six months ended June 30, 2017 and 2016 were approximately $36.8 billion and $23.0 billion, respectively. Total repayments under our credit facilities and commercial paper program were approximately $37.2 billion and $23.6 billion for the six months ended June 30, 2017 and 2016, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs, derivative transactions and construction activities. At June 30, 2017 and December 31, 2016, we had outstanding letters of credit of $105 million and $73 million, respectively.

Senior Notes Repayments

Our $400 million, 6.13% senior notes were repaid in January 2017. We utilized cash on hand and available capacity under our commercial paper program and credit facilities to repay these notes.

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Note 9—Partners' Capital and Distributions

Units Outstanding

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

	Limited Partners	
	Preferred Units	Common Units
Outstanding at December 31, 2016	64,388,853	669,194,419
Issuances of Series A preferred units in connection with in-kind distributions	2,601,300	—
Sales of common units	—	54,119,893
Issuance of common units in connection with acquisition of interest in Advantage Joint Venture (Note 6)	—	1,252,269
Issuances of common units under LTIP	—	130,154
Outstanding at June 30, 2017	66,990,153	724,696,735

	Limited Partners	
	Preferred Units	Common Units
Outstanding at December 31, 2015	—	397,727,624
Sale of Series A preferred units	61,030,127	—
Issuance of Series A preferred units in connection with in-kind distribution	858,439	—
Issuance of common units under LTIP	—	9,104
Outstanding at June 30, 2016	61,888,566	397,736,728

Sales of Common Units

The following table summarizes our sales of common units during the six months ended June 30, 2017 (net proceeds in millions):

Type of Offering	Common Units Issued		Net Proceeds [1]	
Continuous Offering Program	4,033,567		$ 129	(2)
Omnibus Agreement [3]	50,086,326	(4)	1,535	
	54,119,893		$ 1,664	

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

(2) We pay commissions to our sales agents in connection with common units issuances under our Continuous Offering Program. We paid $1 million of such commissions during the six months ended June 30, 2017.

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

(4) Includes (i) approximately 1.8 million common units issued to AAP in connection with PAGP's issuance of Class A shares under its Continuous Offering Program and (ii) 48.3 million common units issued to AAP in connection with PAGP's March 2017 underwritten offering.

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Distributions

Cash Distributions. The following table details the distributions paid in cash during or pertaining to the first six months of 2017 (in millions, except per unit data):

Distribution Payment Date	Distributions Common Unitholders Public	AAP	Total Cash Distribution	Cash Distribution per Common Unit
August 14, 2017 [(1)]	$240	$159	$ 399	$ 0.55
May 15, 2017	$240	$159	$ 399	$ 0.55
February 14, 2017	$237	$134	$ 371	$ 0.55

(1) Payable to unitholders of record at the close of business on July 31, 2017 for the period April 1, 2017 through June 30, 2017.

On August 7, 2017, we announced that we were engaged in discussions with our Board of Directors regarding a reassessment of our approach to distributions, with a focus on resetting PAA's common unit distribution to a level supported by the distributable cash flow from our fee-based Transportation and Facilities segments. As of such date, no final decisions had been made regarding such potential change, but we indicated that we intended to complete our reassessment and finalize any changes over the course of the ensuing sixty day period.

In-Kind Distributions. On February 14, 2017, we issued 1,287,773 Series A preferred units in lieu of a cash distribution of $34 million on our Series A preferred units outstanding as of the record date for such distribution. On May 15, 2017, we issued 1,313,527 Series A preferred units in lieu of a cash distribution of $34 million on our Series A preferred units outstanding as of the record date for such distribution.

On August 14, 2017, we will issue 1,339,796 Series A preferred units in lieu of a cash distribution of $35 million on our Series A preferred units outstanding as of July 31, 2017, the record date for such distribution. Since the August 14, 2017 Series A preferred unit distribution was declared as payment-in-kind, this distribution payable was accrued to partners’ capital as of June 30, 2017 and thus had no net impact on the Series A preferred unitholders’ capital account.

Note 10—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. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on hydrocarbon commodity (referred to herein as “commodity”) price changes. We use various derivative instruments to manage our exposure to (i) commodity price risk, as well as to optimize our profits, (ii) interest rate risk and (iii) currency exchange rate risk. Our commodity price risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our derivative positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and currency exchange rate risk management policies and procedures are designed to monitor our derivative positions and ensure that those positions are consistent with our objectives and approved strategies. 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. Both at the inception of the hedge and throughout the hedging relationship, we assess whether the derivatives employed are highly effective in offsetting changes in cash flows of anticipated hedged transactions.

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 market, (ii) structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be divided into the following general categories:

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Commodity Purchases and Sales — In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of June 30, 2017, net derivative positions related to these activities included:

- A net long position of 1.4 million barrels associated with our crude oil purchases, which was unwound ratably during July 2017 to match monthly average pricing.
- A net short time spread position of 2.5 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through October 2018.
- A crude oil grade basis position of 37.5 million barrels through December 2019. These derivatives allow us to lock in grade basis differentials.
- A net short position of 16.7 million barrels through December 2020 related to anticipated net sales of our crude oil and NGL inventory.

Pipeline Loss Allowance Oil — As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the loss allowance oil that is to be collected under our tariffs. As of June 30, 2017, our PLA hedges included a long call option position of 0.7 million barrels through December 2018.

Natural Gas Processing/NGL Fractionation — We purchase natural gas for processing and operational needs. Additionally, we purchase NGL mix for fractionation and sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. As of June 30, 2017, we had a long natural gas position of 56.6 Bcf which hedges our natural gas processing and operational needs through December 2020. We also had a short propane position of 8.5 million barrels through December 2018, a short butane position of 2.6 million barrels through December 2018 and a short WTI position of 0.7 million barrels through December 2018. In addition, we had a long power position of 0.5 million megawatt hours, which hedges a portion of our power supply requirements at our Canadian natural gas processing and fractionation plants through December 2019.

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.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge the benchmark interest rate risk 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 payments associated with the underlying debt.

The following table summarizes the terms of our outstanding interest derivatives as of June 30, 2017 (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	16 forward starting swaps (30-year)	$ 400	6/15/2018	2.86 %	Cash flow hedge

Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/14/2019	2.83 %	Cash flow hedge

Currency Exchange Rate Risk Hedging

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

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As of June 30, 2017, our outstanding foreign currency derivatives include derivatives we use to hedge currency exchange risk (i) associated with USD-denominated commodity purchases and sales in Canada and (ii) created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

The following table summarizes our open forward exchange contracts as of June 30, 2017 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2017	$154	$205	$1.00 - $1.33
Forward exchange contracts that exchange USD for CAD:				
	2017	$346	$457	$1.00 - $1.32

Preferred Distribution Rate Reset Option

A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value on our Condensed Consolidated Balance Sheets. Corresponding changes in fair value are recognized in “Other income/(expense), net” in our Condensed Consolidated Statement of Operations. At June 30, 2017 and December 31, 2016, the fair value of this embedded derivative was a liability of approximately $35 million and $32 million, respectively. We recognized a gain of approximately $2 million during the three months ended June 30, 2017 and a net loss of approximately $2 million during the six months ended June 30, 2017. We recognized a gain of $25 million during the three and six months ended June 30, 2016. See Note 11 to our Consolidated Financial Statements included in Part IV of our 2016 Annual Report on Form 10-K for additional information regarding the Preferred Distribution Rate Reset Option.

Summary of Financial Impact

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 that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions are recognized in earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items 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.

A summary of the impact of our derivative activities recognized in earnings is as follows (in millions):

Location of Gain/(Loss)	Three Months Ended June 30, 2017 Derivatives in Hedging Relationships (1)	Derivatives Not Designated as a Hedge	Total	Three Months Ended June 30, 2016 Derivatives in Hedging Relationships (1)	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ —	$ 99	$ 99	$ (1)	$ (159)	$ (160)
Transportation segment revenues	—	—	—	—	1	1
Field operating costs	—	(1)	(1)	—	2	2
Depreciation and amortization	(3)	—	(3)	—	—	—
Interest Rate Derivatives						