PLAINS GP HOLDINGS LP
Form 10-Q
November 06, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2015

OR

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

Commission File Number: 1-36132

PLAINS GP HOLDINGS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	90-1005472
(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. Yes 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). Yes No

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

Large accelerated filer	Accelerated filer
Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

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 30, 2015, there were 227,204,958 Class A Shares outstanding.

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PART I. FINANCIAL INFORMATION

Item 1.UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share data)

	September 30, 2015 (unaudited)	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 25	$ 404
Trade accounts receivable and other receivables, net	1,844	2,615
Inventory	837	891
Other current assets	255	271
Total current assets	2,961	4,181
PROPERTY AND EQUIPMENT	15,492	14,219
Accumulated depreciation	(2,123)	(1,927)
Property and equipment, net	13,369	12,292
OTHER ASSETS		
Goodwill	2,417	2,465
Investments in unconsolidated entities	1,954	1,735
Deferred tax asset	1,849	1,705
Linefill and base gas	910	930
Long-term inventory	166	186
Other long-term assets, net	462	489
Total assets	$ 24,088	$ 23,983
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,365	$ 2,987
Short-term debt	681	1,287

Other current liabilities	434	482
Total current liabilities	3,480	4,756
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $18 and $18, respectively	9,757	8,757
Other long-term debt	772	541
Other long-term liabilities and deferred credits	553	548
Total long-term liabilities	11,082	9,846
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
PARTNERS' CAPITAL		
Class A Shareholders (227,204,958 and 206,933,274 shares outstanding, respectively)	1,797	1,657
Class B Shareholders (378,845,615 and 399,096,499 shares outstanding, respectively)	—	—
Noncontrolling interests	7,729	7,724
Total partners' capital	9,526	9,381
Total liabilities and partners' capital	$ 24,088	$ 23,983

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 5,247	$ 10,788	$ 17,225	$ 32,988
Transportation segment revenues	172	198	538	574
Facilities segment revenues	132	141	393	443
Total revenues	5,551	11,127	18,156	34,005
COSTS AND EXPENSES				
Purchases and related costs	4,701	10,166	15,591	31,116
Field operating costs	348	382	1,111	1,078
General and administrative expenses	60	79	219	260
Depreciation and amortization	110	97	327	294
Total costs and expenses	5,219	10,724	17,248	32,748
OPERATING INCOME	332	403	908	1,257
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	45	29	134	73
Interest expense (net of capitalized interest of $14, $12, $42 and $33, respectively)	(110)	(88)	(322)	(254)
Other expense, net	(4)	(4)	(7)	(2)
INCOME BEFORE TAX	263	340	713	1,074
Current income tax expense	(11)	(10)	(72)	(62)
Deferred income tax expense	(24)	(19)	(48)	(54)
NET INCOME	228	311	593	958
Net income attributable to noncontrolling interests	(196)	(295)	(500)	(913)
NET INCOME ATTRIBUTABLE TO PAGP	$ 32	$ 16	$ 93	$ 45
BASIC AND DILUTED NET INCOME PER CLASS A SHARE	$ 0.14	$ 0.12	$ 0.42	$ 0.33
BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING	225	136	220	136

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(unaudited)		(unaudited)	
Net income	$ 228	$ 311	$ 593	$ 958
Other comprehensive loss	(311)	(167)	(518)	(211)
Comprehensive income/(loss)	(83)	144	75	747
Comprehensive (income)/loss attributable to noncontrolling interests	113	(129)	14	(703)
Comprehensive income attributable to PAGP	$ 30	$ 15	$ 89	$ 44

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

PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN

ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

(in millions)

	Derivative Instruments	Translation Adjustments	Total
	(unaudited)		
Balance at December 31, 2014	$ (159)	$ (308)	$ (467)
Reclassification adjustments	(21)	—	(21)
Deferred loss on cash flow hedges, net of tax	(28)	—	(28)
Currency translation adjustments	—	(469)	(469)
Total period activity	(49)	(469)	(518)

Balance at September 30, 2015	$ (208)	$ (777)	$ (985)

	Derivative Instruments	Translation Adjustments	Total
	(unaudited)		
Balance at December 31, 2013	$ (77)	$ (20)	$ (97)
Reclassification adjustments	16	—	16
Deferred loss on cash flow hedges, net of tax	(57)	—	(57)
Currency translation adjustments	—	(170)	(170)
Total period activity	(41)	(170)	(211)
Balance at September 30, 2014	$ (118)	$ (190)	$ (308)

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Nine Months Ended September 30,	
	2015	2014
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 593	$ 958
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	327	294
Equity-indexed compensation expense	27	91
Inventory valuation adjustments	25	37
Deferred income tax expense	48	54
Gain on sales of linefill and base gas	—	(8)
(Gain)/loss on foreign currency revaluation	(20)	10
Settlement of terminated interest rate hedging instruments	(48)	(7)
Equity earnings in unconsolidated entities	(134)	(73)
Distributions from unconsolidated entities	159	74
Other	(12)	10
Changes in assets and liabilities, net of acquisitions	248	(174)
Net cash provided by operating activities	1,213	1,266
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(104)	(10)
Additions to property, equipment and other	(1,617)	(1,424)
Investment in unconsolidated entities	(213)	(98)
Cash received for sales of linefill and base gas	—	24
Cash paid for purchases of linefill and base gas	(131)	(159)
Proceeds from sales of assets	4	2
Other investing activities	(8)	1
Net cash used in investing activities	(2,069)	(1,664)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) under PAA commercial paper program (Note 6)	151	(683)
Net borrowings/(repayments) under AAP senior secured revolving credit facility (Note 6)	(27)	16
Proceeds from AAP term loan (Note 6)	50	—
Proceeds from the issuance of PAA senior notes (Note 6)	998	1,447
Repayments of PAA senior notes (Note 6)	(549)	—
Net proceeds from the issuance of common units by subsidiaries (Note 7)	1,099	655
Distributions paid to Class A shareholders (Note 7)	(143)	(65)
Distributions paid to noncontrolling interests (Note 7)	(1,086)	(959)

Costs incurred in connection with financing arrangements	(11)	(15)
Other financing activities	(2)	(5)
Net cash provided by financing activities	480	391
Effect of translation adjustment on cash	(3)	(1)
Net decrease in cash and cash equivalents	(379)	(8)
Cash and cash equivalents, beginning of period	404	43
Cash and cash equivalents, end of period	$ 25	$ 35
Cash paid for:		
Interest, net of amounts capitalized	$ 295	$ 245
Income taxes, net of amounts refunded	$ 43	$ 135

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL

(in millions)

	Partners' Capital (Excluding Noncontrolling Interests)		Noncontrolling Interests	Total Partners' Capital
	Class A	Class B		
	(unaudited)			
Balance at December 31, 2014	$ 1,657	$ —	$ 7,724	$ 9,381
Net income	93	—	500	593
Distributions	(143)	—	(1,086)	(1,229)
Deferred tax asset	198	—	—	198
Change in ownership interest in connection with Exchange Right exercises (Note 7)	(4)		4	—
Issuance of common units by subsidiaries	—	—	1,099	1,099
Settlement of employee income tax withholding obligations under LTIP	—	—	(13)	(13)
Equity-indexed compensation expense	—	—	20	20
Distribution equivalent right payments	—	—	(5)	(5)
Other comprehensive loss	(4)	—	(514)	(518)
Balance at September 30, 2015	$ 1,797	$ —	$ 7,729	$ 9,526

	Partners' Capital (Excluding Noncontrolling Interests)		Noncontrolling Interests	Total Partners' Capital
	Class A	Class B		
	(unaudited)			
Balance at December 31, 2013	$ 1,035	$ —	$ 7,244	$ 8,279
Net income	45	—	913	958
Distributions	(65)	—	(959)	(1,024)
Deferred tax asset	23	—	—	23
Change in ownership interest in connection with Exchange Right exercises (Note 7)	(1)	—	1	—
Issuance of common units by subsidiaries	—	—	655	655
Issuance of PAA common units under LTIP	—	—	1	1
Settlement of employee income tax withholding obligations under LTIP	—	—	(19)	(19)
Equity-indexed compensation expense	1	—	30	31
Distribution equivalent right payments	—	—	(5)	(5)
Other comprehensive loss	(1)	—	(210)	(211)
Other	—	—	(1)	(1)

Balance at September 30, 2014	$ 1,037	$ —	$ 7,650	$ 8,687

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

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1—Organization and Basis of Consolidation and Presentation

Organization

Plains GP Holdings, L.P. (“PAGP”) is a Delaware limited partnership formed on July 17, 2013 to own an interest in the general partner and incentive distribution rights (“IDRs”) of Plains All American Pipeline, L.P. (“PAA”), a publicly traded Delaware limited partnership. PAGP has elected to be treated as a corporation for U.S. federal income tax purposes. As used in this Form 10-Q and unless the context indicates otherwise (taking into account the fact that PAGP has no operating activities apart from those conducted by PAA and its subsidiaries), the terms “Partnership,” “we,” “us,” “our,” “ours” and similar terms refer to PAGP and its subsidiaries.

As of September 30, 2015, our sole assets consisted of (i) a 100% managing member interest in Plains All American GP LLC (“GP LLC”) and (ii) an approximate 37% limited partner interest in Plains AAP, L.P. (“AAP”) through our ownership of 227,204,958 Class A units of AAP (“AAP units”). GP LLC is a Delaware limited liability company that holds the general partner interest in AAP. AAP is a Delaware limited partnership that directly owns all of PAA’s IDRs and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP LLC (“PAA GP”), a Delaware limited liability company that directly holds the 2% general partner interest in PAA. Plains GP Holdings LLC, a Delaware limited liability company, is our general partner.

GP LLC manages the business and affairs of PAA and AAP. Except for certain matters relating to PAA that require the approval of the limited partners of PAA, and certain matters relating to AAP that require the approval of the limited partners of AAP or of us as the sole member of GP LLC, either pursuant to the governing documents of PAA, AAP or GP LLC, or as may be required by non-waivable provisions of applicable law, GP LLC has full and complete authority, power and discretion to manage and control the business, affairs and property of PAA and AAP, to make all decisions regarding those matters and to perform any and all other acts or activities customary or incident to the management of PAA and AAP’s business, including the execution of contracts and management of litigation. GP LLC employs all domestic officers and personnel involved in the operation and management of PAA and AAP. PAA’s Canadian officers and personnel are employed by Plains Midstream Canada ULC (“PMC”).

PAA is a publicly traded master limited partnership that owns and operates midstream energy infrastructure and provides logistics services for crude oil, natural gas liquids (“NGL”), natural gas and refined products. PAA owns 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 11 for further discussion of our operating segments.

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Definitions

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

AOCI	=	Accumulated other comprehensive income/(loss)
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
DERs	=	Distribution equivalent rights
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 2014 Annual Report on Form 10-K. The accompanying condensed consolidated financial statements include the accounts of PAGP and all of its wholly owned subsidiaries and those entities that it controls. Under GAAP, we consolidate PAA, AAP and GP LLC. Amounts associated with the interests in these entities not owned by us are reflected in our results of operations as net income attributable to noncontrolling interests and on our balance sheet in the partners' capital section as noncontrolling interests. Investments in entities over which we have significant influence but not control are accounted for by the equity method. 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. These reclassifications do not affect net income attributable to PAGP. The condensed consolidated balance sheet data as of December 31, 2014 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, 2015 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

In September 2015, the FASB issued guidance to simplify the accounting for measurement-period adjustments for provisional amounts recognized in a business combination by eliminating the requirement for an acquirer to retrospectively account for measurement-period adjustments. Under the updated guidance, the acquirer must recognize adjustments in the reporting period in which the adjustment amounts are determined and the effect on earnings as a result of the change to the provisional amounts must be calculated as if the accounting had been completed at the acquisition date. This guidance will become effective for interim and annual periods beginning after December 15, 2015, with early

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adoption permitted, and must be applied prospectively. We expect to adopt this guidance on January 1, 2016, and our adoption is not expected to have a material impact on our financial position, results of operations or cash flows.

In July 2015, the FASB issued guidance to simplify the measurement of inventory. This updated guidance requires entities to measure inventory at the lower of cost and net realizable value; however, inventory measured using last-in, first-out and the retail inventory method is unchanged by this update. This guidance will become effective for interim and annual periods beginning after December 15, 2016, with prospective application required. Early adoption is permitted, including adoption in an interim period. We expect to adopt this guidance on January 1, 2017, and we are currently evaluating the impact that adopting this guidance will have on our financial position, results of operations and cash flows.

In April 2015, the FASB issued guidance to simplify the presentation of debt issuance costs in entities' financial statements. This updated guidance requires entities to present such costs as a direct deduction from the related debt liability, consistent with debt discounts. Additionally, amortization of the debt issuance costs will be required to be reported as interest expense. This guidance will become effective for interim and annual periods beginning after December 15, 2015, with retrospective application required for all prior periods presented. Early adoption is permitted for financial statements that have not been previously issued. We expect to adopt this guidance during the fourth quarter of 2015. We do not believe our adoption will have a material impact on our financial position, results of operations or cash flows.

In February 2015, the FASB issued guidance that revises the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. All legal entities are subject to reevaluation under the revised consolidation model. Among other things, this guidance (i) modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities, (ii) eliminates the presumption that a general partner should consolidate a limited partnership and (iii) affects the consolidation analysis of reporting entities that are involved with variable interest entities, particularly those that have fee arrangements and related party relationships. This guidance will become effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted, including adoption in an interim period. We will adopt this guidance on January 1, 2016. We do not believe our adoption will have a material impact on our financial position, results of operations or cash flows.

In January 2015, as part of its initiative to reduce complexity in accounting standards, the FASB issued guidance to eliminate the concept of extraordinary items from GAAP. This guidance will become effective for interim and annual periods beginning after December 15, 2015. We will adopt this guidance on January 1, 2016. We do not believe our adoption will have a material impact on our financial position, results of operations or cash flows.

In May 2014, the FASB issued guidance regarding the recognition of revenue from contracts with customers 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. The guidance also

requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. This guidance 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. In August 2015, the FASB issued guidance deferring the effective date to interim and annual periods beginning after December 15, 2017. Therefore, we expect to adopt this guidance on January 1, 2018, and we are currently evaluating which transition approach to apply and the impact that adopting this guidance will have on our financial position, results of operations and cash flows.

In April 2014, the FASB issued guidance that modifies the criteria under which assets to be disposed of are evaluated to determine if such assets qualify as a discontinued operation and requires new disclosures for both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This guidance is effective prospectively for annual and interim reporting periods beginning after December 15, 2014. We adopted this guidance on January 1, 2015. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

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Note 3—Net Income Per Class A Share

Basic net income per Class A share is determined by dividing net income attributable to PAGP by the weighted-average number of Class A shares outstanding during the period. Class B shares do not share in the earnings of the Partnership. Accordingly, basic and diluted net income per Class B share has not been presented.

Diluted net income per Class A share is determined by dividing net income attributable to PAGP by the diluted weighted-average number of Class A shares outstanding during the period. For purposes of calculating diluted net income per Class A share, both the net income attributable to PAGP and the diluted weighted-average number of Class A shares outstanding consider the impact of possible future exchanges of (i) AAP units and the associated Class B shares into our Class A shares and (ii) certain Class B units of AAP (referred to herein as "AAP Management Units") into our Class A shares. In addition, the calculation of the diluted weighted-average number of Class A shares outstanding considers the effect of potentially dilutive awards under the Plains GP Holdings, L.P. Long-Term Incentive Plan (the "PAGP LTIP").

All AAP Management Units that have satisfied the applicable performance conditions are considered potentially dilutive. Exchanges of potentially dilutive AAP units and AAP Management Units are assumed to have occurred at the beginning of the period and the incremental income attributable to PAGP resulting from the assumed exchanges is representative of the incremental income that would have been attributable to PAGP if the assumed exchanges occurred on that date. Our outstanding PAGP LTIP awards that contemplate the issuance of Class A shares are considered dilutive and are reduced by a hypothetical share repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

For the three and nine months ended September 30, 2015, and the same periods in 2014, the possible exchange of any AAP units and certain AAP Management Units would not have had a dilutive effect on basic net income per Class A share. For the three and nine months ended September 30, 2015 and 2014, our PAGP LTIP awards were dilutive. However, there were less than 0.1 million dilutive LTIP awards for each of the three and nine months ended September 30, 2015 and 2014, which did not change the presentation of weighted average Class A shares outstanding or net income per Class A share. The following table illustrates the calculation of basic and diluted net income per Class A share for the three and nine months ended September 30, 2015 and 2014 (in millions, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Basic and Diluted Net Income per Class A Share				
Net income attributable to PAGP	$ 32	$ 16	$ 93	$ 45
Basic and diluted weighted average Class A shares outstanding	225	136	220	136

Basic and diluted net income per Class A share	$ 0.14	$ 0.12	$ 0.42	$ 0.33

Note 4—Accounts Receivable

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

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 September 30, 2015 and December 31, 2014, we had received $110 million and $180 million, respectively, of advance cash payments from third parties to mitigate credit risk. We also received $46 million and $198

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million, as of September 30, 2015 and December 31, 2014, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. The decrease in standby letters of credit and advance cash payments from third parties as of September 30, 2015 compared to December 31, 2014 is largely due to a decrease in exposure to various customers requiring letters of credit. 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 such 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 September 30, 2015 and December 31, 2014, 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 $4 million as of both September 30, 2015 and December 31, 2014. 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 as of the dates indicated (barrels and natural gas volumes in thousands and carrying value in millions):

	September 30, 2015				December 31, 2014			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)
Inventory								
Crude oil	11,796	barrels	$ 475	$ 40.27	6,465	barrels	$ 304	$ 47.02
NGL	18,461	barrels	272	$ 14.73	13,553	barrels	454	$ 33.50
Natural gas	17,923	Mcf	48	$ 2.68	32,317	Mcf	102	$ 3.16
Other	N/A		42	N/A	N/A		31	N/A
Inventory subtotal			837				891	
Linefill and base gas								
Crude oil	12,327	barrels	724	$ 58.73	11,810	barrels	744	$ 63.00
NGL	1,348	barrels	45	$ 33.38	1,212	barrels	52	$ 42.90

Natural gas	30,812	Mcf	141	$ 4.58	28,612	Mcf	134	$ 4.68
Linefill and base gas subtotal			910				930	
Long-term inventory								
Crude oil	3,434	barrels	143	$ 41.64	2,582	barrels	136	$ 52.67
NGL	1,652	barrels	23	$ 13.92	1,681	barrels	50	$ 29.74
Long-term inventory subtotal			166				186	
Total			$ 1,913				$ 2,007	

(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.

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 $25 million during the nine months ended September 30, 2015, which primarily related to the writedown of our NGL inventory due to declines in prices during the first quarter of 2015. The loss was substantially offset by a portion of the derivative mark-to-market gain that was recognized in the fourth quarter of 2014. See Note 8 for

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discussion of our derivative and risk management activities. During the nine months ended September 30, 2014, we recorded a charge of $37 million related to the writedown of our natural gas inventory that was purchased in conjunction with managing natural gas storage deliverability requirements during the extended period of severe cold weather in the first quarter of 2014.

Note 6—Debt

Debt consisted of the following as of the dates indicated (in millions):

	September 30, 2015	December 31, 2014
SHORT-TERM DEBT		
PAA commercial paper notes, bearing a weighted-average interest rate of 0.43% and 0.46%, respectively (1)	$ 678	$ 734
PAA senior notes:		
5.25% senior notes due June 2015	—	150
3.95% senior notes due September 2015	—	400
Other	3	3
Total short-term debt	681	1,287
LONG-TERM DEBT		
PAA senior notes, net of unamortized discount of $18 and $18, respectively (2)	9,757	8,757
PAA commercial paper notes, bearing a weighted-average interest rate of 0.43% (2)	208	—
AAP term loan, bearing a weighted-average interest rate of 1.8% and 1.8%, respectively	550	500
AAP senior secured revolving credit facility, bearing a weighted-average interest rate of 1.8% and 1.8%, respectively	9	36
Other	5	5
Total long-term debt	10,529	9,298
Total debt (3)	$ 11,210	$ 10,585

(1) We classified these PAA commercial paper notes as short-term at September 30, 2015 and December 31, 2014 as these notes 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 September 30, 2015, we have classified PAA's $175 million, 5.88% senior notes due August 2016 and a portion of PAA's commercial paper notes as long-term based on PAA's ability and intent to refinance such amounts

on a long-term basis.

(3) PAA's fixed-rate senior notes (including current maturities) had a face value of approximately $9.8 billion and $9.3 billion as of September 30, 2015 and December 31, 2014, respectively. We estimated the aggregate fair value of these notes as of September 30, 2015 and December 31, 2014 to be approximately $9.7 billion and $9.9 billion, respectively. PAA's 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 credit facilities and the PAA commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for the PAA senior notes, credit facilities and the PAA commercial paper program are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

Credit Facilities

In January 2015, PAA entered into an agreement for a 364-day senior unsecured revolving credit facility with a borrowing capacity of $1.0 billion. Borrowings accrue interest based, at PAA's election, on either the Eurocurrency Rate

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or the Base Rate, as defined in the agreement, in each case plus a margin based on PAA's credit rating at the applicable time. In August 2015, PAA amended this agreement to extend the maturity date to August 2016.

In August 2015, PAA also extended the maturity dates of its senior secured hedged inventory facility and its senior unsecured revolving credit facility to August 2018 and August 2020, respectively.

In August 2015, AAP amended its credit agreement to, among other things, (i) increase its term loan commitments from $500 million to $550 million, (ii) increase the aggregate commitments under its senior secured revolving credit facility from $75 million to $125 million and (iii) extend the maturity date of the term loan and senior secured revolving credit facility to August 2020. In addition, the amendment provides for a $50 million accordion feature, which may be used to expand the term loan and/or revolving credit facility commitments.

Borrowings and Repayments

Total borrowings under credit agreements and the PAA commercial paper program for the nine months ended September 30, 2015 and 2014 were approximately $37.1 billion and $55.7 billion, respectively. Total repayments under credit agreements and the PAA commercial paper program were approximately $36.9 billion and $56.3 billion for the nine months ended September 30, 2015 and 2014, 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 September 30, 2015 and December 31, 2014, we had outstanding letters of credit of $44 million and $87 million, respectively.

Senior Notes Issuances

In August 2015, PAA completed the issuance of $1.0 billion, 4.65% senior notes due 2025 at a public offering price of 99.846%. Interest payments are due on April 15 and October 15 of each year, commencing on April 15, 2016.

Senior Notes Repayments

The PAA $150 million, 5.25% senior notes and $400 million, 3.95% senior notes were repaid in June 2015 and September 2015, respectively. We utilized cash on hand and available capacity under the PAA commercial paper program to repay these notes.

Note 7—Partners' Capital and Distributions

Distributions

The following table details the distributions paid to Class A shareholders during or pertaining to the first nine months of 2015 (in millions, except per share data):

Date Declared	Distribution Date	Distributions to Class A Shareholders	Distributions per Class A Share
October 7, 2015	November 13, 2015 (1)	$ 52	$ 0.231
July 7, 2015	August 14, 2015	$ 51	$ 0.227
April 7, 2015	May 15, 2015	$ 50	$ 0.222
January 8, 2015	February 13, 2015	$ 42	$ 0.203

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(1) Payable to shareholders of record at the close of business on October 30, 2015 for the period July 1, 2015 through September 30, 2015.

Exchange Rights

Holders of AAP units and their permitted transferees each have the right to exchange all or a portion of their AAP units for Class A shares at an exchange ratio of one Class A share for each AAP unit exchanged (referred to herein as their "Exchange Right"). This Exchange Right may be exercised only if, simultaneously therewith, an equal number of Class B shares and general partner units are transferred by the exercising party to us. For additional information regarding Exchange Rights, see Note 11 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K. During the nine months ended September 30, 2015, certain holders of AAP units and their permitted transferees exercised their Exchange Right, which resulted in the exchange of AAP units, general partner units and our Class B shares for our Class A shares. The impact of such Exchange Right exercises on our Class A and Class B shares outstanding is reflected in the table below.

Shares Outstanding

The following table presents the activity for our Class A shares and Class B shares for the nine months ended September 30, 2015:

	Class B Shares	Class A Shares
Balance at December 31, 2014	399,096,499	206,933,274
Shares (exchanged)/issued in connection with Exchange Right exercises	(20,250,884)	20,250,884
Shares issued in connection with PAGP LTIP award vestings	—	20,800
Balance at September 30, 2015	378,845,615	227,204,958

Consolidated Subsidiaries

Noncontrolling Interests in Subsidiaries

As of September 30, 2015, noncontrolling interests in our subsidiaries consisted of (i) a 98% limited partner interest in PAA, (ii) an approximate 63% limited partner interest in AAP that consists of Class A units and AAP Management

Units (a profits interest) and (iii) a 25% interest in SLC Pipeline LLC.

Subsidiary Distributions

PAA Distributions. The following table details the distributions to PAA's partners paid during or pertaining to the first nine months of 2015, net of incentive distribution reductions (in millions, except per unit data):

		Distributions to PAA's Partners				Distributions per limited
Date Declared	Distribution Date	Limited Partners	AAP 2%	Incentive	Total	partner unit
October 7, 2015	November 13, 2015 (1)	$ 279	$ 6	$ 148	$ 433	$ 0.7000
July 7, 2015	August 14, 2015	$ 276	$ 6	$ 146	$ 428	$ 0.6950
April 7, 2015	May 15, 2015	$ 272	$ 6	$ 142	$ 420	$ 0.6850
January 8, 2015	February 13, 2015	$ 254	$ 5	$ 131	$ 390	$ 0.6750

(1) Payable to unitholders of record at the close of business on October 30, 2015 for the period July 1, 2015 through September 30, 2015.

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AAP Distributions. The following table details the distributions to AAP's partners from distributions received from PAA paid during or pertaining to the first nine months of 2015 (in millions):

			Distributions to AAP's Partners		
Distribution Date	Distributions Received by AAP from PAA	Cash Reserves	Total	Noncontrolling Interests	PAGP
November 13, 2015 (1)	$ 154	$ (3)	$ 151	$ 98	$ 53
August 14, 2015	$ 152	$ (5)	$ 147	$ 96	$ 51
May 15, 2015	$ 148	$ (3)	$ 145	$ 95	$ 50
February 13, 2015	$ 136	$ (3)	$ 133	$ 91	$ 42

(1) Payable to unitholders of record at the close of business on October 30, 2015 for the period July 1, 2015 through September 30, 2015.

Other Distributions. During the nine months ended September 30, 2015, distributions of $2 million were paid to noncontrolling interests in SLC Pipeline LLC.

Sales of Common Units by Subsidiaries

PAA Continuous Offering Program. During the nine months ended September 30, 2015, PAA issued an aggregate of approximately 1.1 million common units under its continuous offering program, generating proceeds of $58 million, net of offering costs.

PAA Underwritten Offering. In March 2015, PAA completed an underwritten public offering of 21.0 million common units, generating proceeds of approximately $1.0 billion, net of costs associated with the offering.

Note 8—Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. 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 (i) manage our exposure to commodity price risk, as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange rate risk. Our commodity 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 on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

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 September 30, 2015, net derivative positions related to these activities included:

- An average of 159,000 barrels per day net long position (total of 4.9 million barrels) associated with our crude oil purchases, which was unwound ratably during October 2015 to match monthly average pricing.

- A net short time spread position averaging 12,900 barrels per day (total of 5.9 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through December 2016.

- An average of 8,200 barrels per day (total of 2.2 million barrels) of crude oil grade spread positions through June 2016. These derivatives allow us to lock in grade basis differentials.

- A net short position of 15.8 Bcf through May 2016 related to anticipated sales of natural gas inventory and base gas requirements.

- A net short position of 22.7 million barrels through June 2017 related to anticipated net sales of our crude oil and NGL inventory.

Storage Capacity Utilization — We own a significant amount of crude oil, NGL and refined products storage capacity other than that used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk in a backwardated market structure. As of September 30, 2015, we used derivatives to manage the risk of potentially not utilizing an average of approximately 2.0 million barrels per month of storage capacity through January 2018. These positions involve no outright price exposure, but instead enable us to profit in the event it is not economic to store oil.

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 allowance oil that is to be collected under our tariffs. As of September 30, 2015, our PLA hedges included a net short position consisting of crude oil futures and swaps for an average of approximately 400 barrels per day (total of 0.2 million barrels) and a long call option position of approximately 1.7 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

September 30, 2015, we had a long natural gas position of 9.7 Bcf through December 2016, a short propane position of 2.2 million barrels through December 2016, a short butane position of 0.6 million barrels through December 2016 and a short WTI position of 0.2 million barrels through December 2016. 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 2018.

To the extent they qualify and we decide to make the election, all of our commodity derivatives for which we elect hedge accounting are designated as cash flow hedges. 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 purchase and sale agreements qualify for the normal purchases and normal sales scope exception.

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Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated and outstanding 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. As of September 30, 2015, AOCI includes deferred losses of $192 million that relate to open and terminated interest rate derivatives that were designated as cash flow hedges. The terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

We have entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted interest payments through 2049. The following table summarizes the terms of our forward starting interest rate swaps as of September 30, 2015 (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	6/15/2016	3.06	%	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2017	3.14	%	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/15/2018	3.20	%	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/14/2019	2.83	%	Cash flow hedge

In June 2015, we made a cash payment of approximately $31 million in connection with the termination of ten forward starting swaps that had an aggregate notional amount of $250 million and an average fixed rate of 3.60%. In August 2015, we made a cash payment of approximately $21 million in connection with the termination of seven forward starting swaps that had an aggregate notional amount of $250 million and an average fixed rate of 3.03%. In conjunction with these terminations, we recognized a loss of $4 million in interest expense attributable to an anticipated hedged transaction that is no longer probable of occurring.

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 and forwards.

As of September 30, 2015, our outstanding foreign currency derivatives include derivatives we use to (i) hedge currency exchange risk associated with USD-denominated commodity purchases and sales in Canada and (ii) hedge currency exchange risk created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

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The following table summarizes our open forward exchange contracts as of September 30, 2015 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD		
Forward exchange contracts that exchange CAD for USD:						
	2015	$ 152	$ 202	$ 1.00	-	$ 1.33
	2016	57	76	$ 1.00	-	$ 1.33
		$ 209	$ 278			
Forward exchange contracts that exchange USD for CAD:						
	2015	$ 173	$ 222	$ 1.00	-	$ 1.28
	2016	57	73	$ 1.00	-	$ 1.28
		$ 230	$ 295			

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 for the periods indicated is as follows (in millions):

	Three Months Ended September 30, 2015		
	Derivatives in Hedging Relationships		
	Gain/(Loss) Reclassified	Gain/(Loss) Recognized	Other Derivatives Not

Location of Gain/(Loss)	Reclassified from AOCI into Income (2)	Recognized in Income (3)(1)	Designated as a Hedge	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ 42	$ —	$ 14	$ 56
Transportation segment revenues	—	—	2	2
Field operating costs	—	—	(9)	(9)
Interest Rate Derivatives				
Interest expense	(2)	(2)	—	(4)
Foreign Currency Derivatives				
Supply and Logistics segment revenues	—	—	(9)	(9)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 40	$ (2)	$ (2)	$ 36

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	Three Months Ended September 30, 2014			
Location of Gain/(Loss)	Derivatives in Hedging Relationships Gain/(Loss) Reclassified from AOCI into Income (2)	Other Gain/(Loss) Recognized in Income (3)	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ (4)	$ —	$ (17)	$ (21)
Field operating costs	—	—	(2)	(2)
Interest Rate Derivatives				
Interest expense	(1)	—	—	(1)
Foreign Currency Derivatives				
Supply and Logistics segment revenues	—	—	(17)	(17)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (5)	$ —	$ (36)	$ (41)

	Nine Months Ended September 30, 2015			
Location of Gain/(Loss)	Derivatives in Hedging Relationships Gain/(Loss) Reclassified from AOCI into Income (2)	Other Gain/(Loss) Recognized in Income (3)	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				

Supply and Logistics segment revenues	$ 30	$ —	$ 24	$ 54
Transportation segment revenues	—	—	6	6
Field operating costs	—	—	(11)	(11)
Interest Rate Derivatives				
Interest expense	(9)	—	—	(9)
Foreign Currency Derivatives				
Supply and Logistics segment revenues	—	—	(26)	(26)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 21	$ —	$ (7)	$ 14

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	Nine Months Ended September 30, 2014			
	Derivatives in Hedging Relationships			
Location of Gain/(Loss)	Gain/(Loss) Reclassified from AOCI into Income (1) (2)	Other Gain/(Loss) Recognized in Income (3)	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ (12)	$ —	$ (17)	$ (29)
Field operating costs	—	—	(3)	(3)
Interest Rate Derivatives				
Interest expense	(4)	—	—	(4)
Foreign Currency Derivatives				
Supply and Logistics segment revenues	—	—	(17)	(17)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (16)	$ —	$ (37)	$ (53)

(1) Represents gains/(losses) on cash flow hedges reclassified from AOCI to income during the period.

(2) During the nine months ended September 30, 2015 we reclassified a loss of approximately $4 million from AOCI to Interest expense as a result of an anticipated hedged transaction that is no longer probable of occurring. All of our anticipated hedged transactions were deemed probable of occurring during the three months ended September 30, 2015 and the three and nine months ended September 30, 2014.

(3) Amounts represent ineffective portion of cash flow hedges.

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The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheets on a gross basis as of September 30, 2015 (in millions):

	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 7	Other current assets	$ (1)
	Other long-term assets, net	1		
Interest rate derivatives			Other current liabilities	(19)
			Other long-term liabilities and deferred credits	(38)
Total derivatives designated as hedging instruments		$ 8		$ (58)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 220	Other current assets	$ (33)
	Other long-term assets, net	16	Other long-term assets, net	(5)
			Other current liabilities	(19)
			Other long-term liabilities and deferred credits	(3)
Foreign currency derivatives			Other current liabilities	(9)
Total derivatives not designated as hedging instruments		$ 236		$ (69)
Total derivatives		$ 244		$ (127)

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The following table summarizes the derivative assets and liabilities on our Condensed Consolidated Balance Sheets on a gross basis as of December 31, 2014 (in millions):

	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 23	Other current assets	$ (12)
	Other long-term assets, net	8	Other long-term assets, net	(1)
Interest rate derivatives			Other current liabilities	(44)
			Other long-term liabilities and deferred credits	(26)
Total derivatives designated as hedging instruments		$ 31		$ (83)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 439	Other current assets	$ (246)
	Other long-term assets, net	23	Other long-term assets, net	(3)
			Other current liabilities	(35)
			Other long-term liabilities and deferred credits	(5)
Foreign currency derivatives			Other current liabilities	(12)
Total derivatives not designated as hedging instruments		$ 462		$ (301)
Total derivatives		$ 493		$ (384)

Our derivative transactions are governed through ISDA (International Swaps and Derivatives Association) 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.

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. As of September 30, 2015, we had a net broker payable of $121 million (consisting of initial margin of $70 million reduced by $191 million of variation margin that had been returned to us). As of December 31, 2014, we had a net broker payable of $133 million (consisting of initial margin of $126 million reduced by $259 million of variation margin that had been returned to us).

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The following table presents information about derivatives and financial assets and liabilities that are subject to offsetting, including enforceable master netting arrangements as of the dates indicated (in millions):

	September 30, 2015		December 31, 2014	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 244	$ (127)	$ 493	$ (384)
Netting adjustment	(39)	39	(262)	262
Cash collateral paid/(received)	(121)	—	(133)	—
Net position - asset/(liability)	$ 84	$ (88)	$ 98	$ (122)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 72	$ —	$ 71	$ —
Other long-term assets, net	12	—	27	—
Other current liabilities	—	(47)	—	(91)
Other long-term liabilities and deferred credits	—	(41)	—	(31)
	$ 84	$ (88)	$ 98	$ (122)

As of September 30, 2015, there was a net loss of $208 million deferred in AOCI. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at September 30, 2015, we do not expect to reclassify a material amount to earnings in the next twelve months. A deferred loss of $16 million is expected to be reclassified to earnings through 2018 and the remainder is expected to be reclassified through 2049. A portion of these amounts is based on market prices as of September 30, 2015; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The net deferred gain/(loss), including tax effects, recognized in AOCI for derivatives for the periods indicated was as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014

Commodity derivatives, net	$ 37	$ 2	$ 12	$ (10)
Interest rate derivatives, net	(85)	(8)	(40)	(47)
Total	$ (48)	$ (6)	$ (28)	$ (57)

At September 30, 2015 and December 31, 2014, 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 cleared derivatives as described above, we do not require our non-cleared derivative counterparties to post collateral with us.

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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 as of the dates indicated (in millions):

	Fair Value as of September 30, 2015				Fair Value as of December 31, 2014			
Recurring Fair Value Measures (1)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$ 90	$ 82	$ 11	$ 183	$ (85)	$ 261	$ 15	$ 191
Interest rate derivatives	—	(57)	—	(57)	—	(70)	—	(70)
Foreign currency derivatives	—	(9)	—	(9)	—	(12)	—	(12)
Total net derivative asset/(liability)	$ 90	$ 16	$ 11	$ 117	$ (85)	$ 179	$ 15	$ 109

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

Level 1

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

Level 2

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity, interest rate and foreign currency derivatives that are traded in active markets. In addition, it includes certain physical commodity contracts. The fair value of these derivatives is based on broker price quotations which are corroborated with market observable inputs.

Level 3

Level 3 of the fair value hierarchy includes certain physical commodity contracts. The fair value of our Level 3 physical commodity contracts is based on a valuation model utilizing broker-quoted forward commodity prices, and timing estimates, which involve management judgment. The significant unobservable inputs used in the fair value measurement of our Level 3 derivatives are forward prices obtained from brokers. A significant increase or decrease in these forward prices could result in a material change in fair value to our Level 3 derivatives. We report unrealized gains and losses associated with Level 3 commodity derivatives in our Condensed Consolidated Statements of Operations as Supply and Logistics segment revenues.

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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 for the periods indicated (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Beginning Balance	$ 9	$ 1	$ 15	$ (3)
Gains for the period included in earnings	2	1	1	—
Settlements	(2)	—	(13)	3
Derivatives entered into during the period	2	1	8	3
Ending Balance	$ 11	$ 3	$ 11	$ 3
Change in unrealized gains included in earnings relating to Level 3 derivatives still held at the end of the period	$ 4	$ 2	$ 9	$ 3

Note 9—Equity-Indexed Compensation Plans

We refer to the PAGP LTIP, PAA LTIPs and AAP Management Units collectively as our “equity-indexed compensation plans.” For additional discussion of our equity-indexed compensation plans and awards, see Note 16 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K.

PAGP LTIP Awards

Activity for awards under the PAGP LTIP is summarized in the following table (shares in millions):

	PAGP Shares	Weighted Average Grant Date Fair Value per Share
Outstanding at December 31, 2014	0.1	$ 27.84
Granted (1)	—	$ 27.84
Vested (2)	—	$ 27.84
Outstanding at September 30, 2015	0.1	$ 27.84

(1) During the nine months ended September 30, 2015, less than 0.1 million PAGP LTIP awards were issued under the automatic re-grant feature for awards issued to PAGP directors.

(2) During the nine months ended September 30, 2015, less than 0.1 million PAGP LTIP awards vested and were settled in Class A shares.

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PAA LTIP Awards

Activity for LTIP awards under our equity-indexed compensation plans denominated in PAA units is summarized in the following table (units in millions):

	PAA Units (1)	Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	7.3	$ 41.45
Granted	1.3	$ 38.91
Vested (2)	(2.1)	$ 28.91
Cancelled or forfeited	(0.3)	$ 45.68
Outstanding at September 30, 2015	6.2	$ 44.98

(1) Amounts do not include AAP Management Units.

(2) Approximately 0.5 million PAA common units were issued, net of tax withholding of 0.3 million units, during the nine months ended September 30, 2015 in connection with the settlement of vested awards. The remaining PAA awards that vested during the nine months ended September 30, 2015 (approximately 1.3 million units) were settled in cash.

AAP Management Units

Activity for AAP Management Units is summarized in the following table (in millions):

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value Of Outstanding AAP Management Units (1)
Balance at December 31, 2014	3.0	49.1	47.8	$ 64

Granted	(1.6)	1.6	—		24
Earned	N/A	N/A	0.7		N/A
Balance at September 30, 2015	1.4	50.7	48.5	$	88

(1) Of the $88 million grant date fair value, $57 million had been recognized through September 30, 2015 on a cumulative basis. Of this amount, $1 million was recognized as expense during the nine months ended September 30, 2015.

Other Consolidated Equity-Indexed Compensation Plan Information

The table below summarizes the expense recognized and the value of vested LTIP awards (settled in PAA common units, PAGP shares and cash) under our equity-indexed compensation plans and includes both liability-classified and equity-classified awards for the periods indicated (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Equity-indexed compensation expense/(benefit) (1)	$ (8)	$ 22	$ 27	$ 91
LTIP unit- or share-settled vestings (2)	$ 2	$ 1	$ 37	$ 52
LTIP cash-settled vestings (3)	$ 10	$ —	$ 66	$ 52
DER cash payments (4)	$ 2	$ 2	$ 6	$ 6

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(1) For each of the three months ended September 30, 2015 and 2014, and the nine months ended September 30, 2015, amount includes less than $1 million of expense related to PAGP LTIP awards. For the nine months ended September 30, 2014, amount includes $1 million of expense related to PAGP LTIP awards.

(2) For the nine months ended September 30, 2015, $1 million relates to awards settled in PAGP Class A shares. For the three months ended September 30, 2015 and the three and nine months ended September 30, 2014, all amounts relate to awards settled in PAA common units.

(3) All cash settled vestings for the three and nine months ended September 30, 2015 and 2014 related to PAA LTIP awards.

(4) For each of the three and nine months ended September 30, 2015 and 2014, less than $1 million of cash paid was related to DERs on PAGP LTIP awards.

Note 10—Commitments and Contingencies

Loss Contingencies — General

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

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

Legal Proceedings — General

In the ordinary course of business, we are involved in various legal proceedings, including those arising from regulatory and environmental matters. 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.

Taking into account what we believe to be all relevant known facts and circumstances, and based on what we believe to be reasonable assumptions regarding the application of those facts and circumstances to existing laws and regulations, we do not believe that the outcome of the legal proceedings in which we are currently involved (including those described below) will, individually or in the aggregate, have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Environmental — General

Although over the course of the last several years we have made significant investments in our maintenance and integrity programs, and have hired additional personnel in those areas, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail and storage operations. These releases can result from accidents or from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Damages and liabilities associated with any such releases from our

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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.

At September 30, 2015, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $197 million, of which $96 million was classified as short-term and $101 million was classified as long-term. At December 31, 2014, our estimated undiscounted reserve for environmental liabilities totaled $82 million, of which $13 million was classified as short-term and $69 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in "Accounts payable and accrued liabilities" and "Other long-term liabilities and deferred credits," respectively, on our Condensed Consolidated Balance Sheets. At September 30, 2015 and December 31, 2014, we had recorded receivables totaling $200 million and $8 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly 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 legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve is adequate, costs incurred 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. During 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 includes the United States Coast Guard, the EPA, 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 and contamination monitoring continue, and the cause of the release is currently under investigation.

Shortly after the incident, we developed an initial "worst case" estimate of the amount of oil spilled, representing the maximum volume of oil that we believed could have been spilled based on relevant facts, data and information available at the time of such calculation. Our initial worst case estimate was approximately 2,500 barrels, which was subsequently adjusted down to approximately 2,400 barrels. These estimates were based primarily on information regarding (i) an estimate of the amount of oil that flowed into Line 901 during the period between the estimated time of release and the point when the pumps were shut down and (ii) an estimate of the volume of oil that drained out of

the line due to natural forces based on the characteristics of the pipeline (i.e., length, elevation profile, diameter and location of the release point).

Utilizing information that became available in June as a result of emptying and purging Line 901, we developed an alternative worst case discharge estimate of up to 3,400 barrels. This alternative estimate did not take into account certain factors that, while difficult to quantify, could account for a meaningful portion of the difference between the two estimates. As part of our effort to reconcile the difference between these two estimates, we retained a third party engineering and consulting firm to develop an independent estimate of the worst case discharge.

Although we have not yet received such firm's final written report, we have discussed their findings with them. They have orally advised us that based on their detailed analysis of the pertinent data and materials, their estimate of the worst case discharge is approximately 3,000 barrels. Accordingly, while we have not finalized our calculation of the "worst case" discharge, based on the relatively narrow range of difference between the low and high end of the range of various worst case estimates that have been prepared, we do not anticipate that any variance between these estimates and

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the final estimate of the worst case discharge will have a material impact on our accrual (described below) for the estimated total costs that we have incurred or will incur with respect to the Line 901 incident.

As a result of the Line 901 incident, several governmental agencies and regulators have initiated investigations into the Line 901 incident, various claims have been made against us and a number of lawsuits have been filed against us. Set forth below is a brief summary of such actions and matters:

On May 21, 2015, we received a corrective action order from the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA"), the governmental agency that has jurisdiction over the operation of Line 901 as well as over a second stretch of pipeline extending from Gaviota Pump Station in Santa Barbara County to Emidio Pump Station in Kern County, California (Line 903), requiring us to shut down, purge, review, remediate and test Line 901. On June 3, 2015, the corrective action order was amended to require us to take additional corrective actions with respect to both Lines 901 and 903 (as amended, the "CAO"). Among other requirements, the CAO also obligates us to conduct a root cause failure analysis with respect to Line 901 and present remedial work plans and restart plans to PHMSA prior to returning Line 901 to service; the CAO also imposes a pressure restriction on Line 903 and requires us to take other specified actions with respect to both Lines 901 and 903. We intend to continue to comply with the CAO and to cooperate with any other governmental investigations relating to or arising out of the release. Excavation and removal of the affected section of the pipeline was completed on May 28, 2015. No timeline has been established for the restart of Line 901 or Line 903. By virtue of its statutory authority, PHMSA has the power and authority to impose fines and penalties on us and cause civil or criminal charges to be brought against us. While to date PHMSA has not imposed any such fines or penalties or pursued any such civil or criminal charges, there can be no assurance that such fines or penalties will not be imposed upon us, or that such civil or criminal charges will not be brought against us, in the future.

On September 11, 2015, we received a Notice of Probable Violation and Proposed Compliance Order from PHMSA arising out of its inspection of Lines 901 and 903 in August, September and October of 2013 (the "2013 Audit NOPV"). The 2013 Audit NOPV alleges that the Partnership committed probable violations of various federal pipeline safety regulations by failing to document, or inadequately documenting, certain activities. On October 12, 2015, the Partnership filed a response to the 2013 Audit NOPV. To date, PHMSA has not issued a final order with respect to the 2013 Audit NOPV, nor has it assessed any fines or penalties with respect thereto; however, we cannot provide any assurances that any such fines or penalties will not be assessed against us.

In late May, on behalf of the EPA, the United States Attorney for the Department of Justice, Central District of California, Environmental Crimes Section ("DOJ") began an investigation into whether there were any violations of federal criminal statutes in connection with the Line 901 incident, including potential violations of the federal Clean Water Act. We are cooperating with the DOJ's investigation by responding to their requests for documents and access to our employees. The DOJ has expressed an interest in talking to several of our employees and consistent with the terms of our governing organizational documents, we are funding their defense costs, including the costs of separate counsel engaged to represent such individuals. In addition to the DOJ, the California Attorney General's Office and the District Attorney's Office for the County of Santa Barbara are also investigating the Line 901 incident to determine whether any applicable state or local laws have been violated. On August 26, 2015, we also received a Request for

Information from the EPA relating to Line 901 and we are in the process of responding to such request. While to date no civil or criminal charges have been brought against PAA or any of its affiliates, officers or employees by the DOJ, EPA, California Attorney General or Santa Barbara County District Attorney, and no fines or penalties have been imposed by such governmental agencies, there can be no assurance that such fines or penalties will not be imposed upon us, or that such civil or criminal charges will not be brought against us, in the future.

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 have received a number of claims through the claims line and we are processing those claims as we receive them. In addition, we have also had seven class action lawsuits filed against us, all of which have been filed in the United States District Court for the Central District of California. In general, these lawsuits have been brought by various plaintiffs seeking to establish different classes of claimants that have allegedly been damaged by the release, including potential classes such as persons that derive a significant portion of their income through commercial fishing and harvesting activities in the waters adjacent to Santa

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Barbara County or from businesses that are dependent on marine resources from Santa Barbara County, retail businesses located in historic downtown Santa Barbara, certain owners of oceanfront and/or beachfront property on the Pacific Coast of California, and other classes of individuals and businesses that were allegedly impacted by the release.

There have also been two securities law class action lawsuits filed on behalf of certain purported investors in PAA and/or PAGP against PAA, PAGP and/or certain of their respective officers, directors and underwriters. Both of these lawsuits have been consolidated into a single proceeding in the United States District Court for the Southern District of Texas. In general, these lawsuits allege that the various defendants violated securities laws by misleading investors regarding the integrity of the Partnership's pipelines and related facilities through false and misleading statements, omission of material facts and concealing of the true extent of the spill. The plaintiffs claim unspecified damages as a result of the reduction in value of their investments in PAA and PAGP, which they attribute to the alleged wrongful acts of the plaintiffs. PAA and PAGP deny the allegations in these lawsuits and intend to respond accordingly.

In addition to the foregoing, 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, and we also have exposure to the payment of additional fines, penalties and costs under other applicable federal, state and local laws, statutes and regulations. To the extent any such costs are reasonably estimable, we have included an estimate of such costs in the loss accrual described below.

Taking the foregoing into account, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $257 million, which estimate includes actual and projected emergency response and clean-up costs, natural resource damage assessments and certain third party claims settlements as well as estimates for fines, penalties and certain legal fees. This estimate does not include any lost revenue associated with the shutdown of Line 901 or 903. In addition, 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 expected number of days that clean up, remediation and monitoring services will be required, the number of personnel and equipment required at the site and the rates charged by the associated service and equipment providers, (ii) the duration of the natural resource damage assessment and the ultimate amount of damages determined, (iii) 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, (iv) the determination and calculation of fines and penalties and (v) 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. 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. Our assumptions and estimates may turn out to be inaccurate and our total costs could turn out to be higher; accordingly, we can provide no assurance that we will not have to accrue additional costs in the future with respect to the Line 901 incident.

We have accrued such estimate of aggregate total costs to “Field operating costs” on our Condensed Consolidated Statement of Operations. As of September 30, 2015, we had a remaining undiscounted gross liability of $126 million related to this event, the majority of which is presented as a current liability in “Accounts payable and accrued liabilities” on our Condensed Consolidated Balance Sheets. We maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such environmental liabilities. Subject to such exclusions and deductibles, we believe that our coverage is adequate to cover the current estimated total emergency response and clean-up costs, claims settlement costs and remediation costs and we believe that this coverage is also adequate to cover any potential increase in the estimates for these costs that exceed the amounts currently identified. We therefore have recognized a receivable of $192 million as of September 30, 2015 for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles. A majority of this receivable has been recognized as a current asset in “Trade accounts receivable and other receivables, net” on our Condensed Consolidated Balance Sheets with the offset reducing “Field operating costs” on our Condensed Consolidated Statement of Operations. We have substantially completed the clean-up and remediation efforts, excluding long-term site monitoring activities; however, we expect to make payments for additional costs associated with restoration and monitoring of the area, as well as natural resource damage assessment, legal, professional and regulatory costs, in addition to fines and penalties, during future periods.

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MP29 Release. On July 10, 2015, we experienced a crude oil release of approximately 100 barrels at our Pocahontas Pump Station near the border of Bond and Madison Counties in Illinois, approximately 40 miles from St. Louis, Missouri. The Pocahontas Station is part of the Capwood pipeline that runs from our Patoka Station to Wood River, Illinois. A portion of the released crude oil was contained within our Pocahontas facility, but some of the released crude oil entered a nearby waterway where it was contained with booms. On July 14, 2015, PHMSA issued a corrective action order requiring us to take various actions in response to the release, including remediation, reporting and other actions. We are in the process of satisfying the requirements of the corrective action order. On August 10, 2015, we received a Notice of Violation from the Illinois Environmental Protection Agency alleging violations relating to the release and outlining the activities recommended by the agency to resolve the alleged violations, including the completion of an investigation and various remediation activities. PAA has submitted a work plan to the agency that describes the proposed remediation activities for any remaining hydrocarbon impacts; the agency is currently reviewing the work plan. To date, no fines or penalties have been assessed in this matter; however, it is possible that fines and penalties could be assessed in the future. In connection with this incident, we have also had one class action lawsuit filed against us in the United States District Court for the Southern District of Illinois. In this lawsuit, the plaintiff seeks unspecified money damages and other remedies on behalf of itself and other unspecified similarly situated claimants. We estimate that the aggregate total costs associated with this release will be less than $10 million.

Cushing Tank Cathodic Protection. On May 22, 2015, PHMSA issued a Final Order relating to an April 2013 Notice of Probable Violation and Proposed Compliance Order alleging that we did not maintain adequate cathodic protection for certain tanks at our Cushing Terminal. In its 2013 Notice of Probable Violation, PHMSA maintained that the proprietary cathodic protection system utilized by us for certain of our storage tanks at our Cushing, Oklahoma facility was not contemplated by applicable regulations. In response to the notice, we provided extensive documentation and supporting information regarding the effectiveness of the technology we were utilizing, including past communications with PHMSA regarding the topic. At a hearing in August 2013 we gave a formal presentation on the technology, provided empirical data confirming its effectiveness and also had a third party corrosion expert witness speak to the effectiveness of the technology. Almost two years later, PHMSA issued the Final Order and Compliance Order dated May 22, 2015 ruling against our position, assessing a penalty of $102,900 and specifying certain corrective actions to be completed by us. We chose not to further contest this matter and paid the penalty on June 5, 2015. On July 14, 2015, we submitted to PHMSA a Remediation Plan and schedule to satisfy the conditions of the Compliance Order.

In the Matter of Bakersfield Crude Terminal LLC et al. On April 30, 2015, the EPA issued a Finding and Notice of Violation (“NOV”) to Bakersfield Crude Terminal LLC, our subsidiary, for alleged violations of the Clean Air Act, as amended. The NOV, which cites 10 separate rule violations, questions the validity of construction and operating permits issued to our Bakersfield rail unloading facility in 2012 and 2014 by the San Joaquin Valley Air Pollution Control District (the “SJV District”). We believe we fully complied with all applicable regulatory requirements and that the permits issued to us by the SJV District are valid. To date, no fines or penalties have been assessed in this matter; however, it is possible that fines and penalties could be assessed in the future.

National Energy Board Audit. In the third quarter of 2014, the National Energy Board (“NEB”) of Canada notified PMC that various corrective actions from a 2010 audit had not been completed to the satisfaction of the NEB. The NEB initiated a process to assess PMC’s approach to compliance with the NEB’s Onshore Pipeline Regulations, which

process resulted in the issuance by the NEB of an order on January 15, 2015 that imposed six conditions on PMC designed to enhance PMC's ability to operate its pipelines in a manner that protects the public and the environment. The conditions include the filing of certain safety critical tasks, controls and programs with the NEB, external audits of certain PMC programs and systems, and periodic update meetings with NEB staff regarding the status and progress of corrective actions. In early February 2015, the NEB imposed a penalty on PMC of $76,000 CAD related to these issues. It is possible that additional fines and penalties may be assessed against PMC in the future related to this matter.

Kemp River Pipeline Releases. During May and June 2013, two separate releases were discovered on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the release of approximately 700 barrels of condensate and light crude oil. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. Final investigation by the Alberta Energy Regulator is not complete. To date, no charges, fines or penalties have been assessed against PMC with respect to these releases; however, it is possible that fines or penalties may be assessed against PMC in the future. We estimate that the aggregate clean-up and remediation costs

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associated with these releases will be $15 million. Through September 30, 2015, we spent $9 million in connection with clean-up and remediation activities.

Bay Springs Pipeline Release. During February 2013, we experienced a crude oil release of approximately 120 barrels on a portion of one of our pipelines near Bay Springs, Mississippi. Most of the released crude oil was contained within our pipeline right of way, but some of the released crude oil entered a nearby waterway where it was contained with booms. The EPA has issued an administrative order requiring us to take various actions in response to the release, including remediation, reporting and other actions. We have satisfied the requirements of the administrative order; however, we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was $6 million.

Note 11—Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on measures including segment profit and maintenance capital investment. We define segment profit 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. Each of the items above excludes depreciation and amortization. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets.

The following table reflects certain financial data for each segment for the periods indicated (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Three Months Ended September 30, 2015				
Revenues:				
External customers	$ 172	$ 132	$ 5,247	$ 5,551
Intersegment (1)	229	131	7	367
Total revenues of reportable segments	$ 401	$ 263	$ 5,254	$ 5,918
Equity earnings in unconsolidated entities	$ 45	$ —	$ —	$ 45
Segment profit (2) (3)	$ 254	$ 146	$ 87	$ 487
Maintenance capital	$ 34	$ 16	$ 2	$ 52
Three Months Ended September 30, 2014				
Revenues:				
External customers	$ 198	$ 141	$ 10,788	$ 11,127
Intersegment (1)	226	140	5	371

Total revenues of reportable segments	$ 424	$ 281	$ 10,793	$ 11,498
Equity earnings in unconsolidated entities	$ 29	$ —	$ —	$ 29
Segment profit (2) (3)	$ 231	$ 147	$ 152	$ 530
Maintenance capital	$ 35	$ 19	$ 2	$ 56

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	Transportation	Facilities	Supply and Logistics	Total
Nine Months Ended September 30, 2015				
Revenues:				
External customers	$ 538	$ 393	$ 17,225	$ 18,156
Intersegment (1)	665	396	13	1,074
Total revenues of reportable segments	$ 1,203	$ 789	$ 17,238	$ 19,230
Equity earnings in unconsolidated entities	$ 134	$ —	$ —	$ 134
Segment profit (2) (3)	$ 681	$ 432	$ 258	$ 1,371
Maintenance capital	$ 101	$ 48	$ 5	$ 154
Nine Months Ended September 30, 2014				
Revenues:				
External customers	$ 574	$ 443	$ 32,988	$ 34,005
Intersegment (1)	648	415	33	1,096
Total revenues of reportable segments	$ 1,222	$ 858	$ 33,021	$ 35,101
Equity earnings in unconsolidated entities	$ 73	$ —	$ —	$ 73
Segment profit (2) (3)	$ 658	$ 435	$ 534	$ 1,627
Maintenance capital	$ 111	$ 34	$ 6	$ 151

(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market. For further discussion, see “Analysis of Operating Segments” under Item 7 of our 2014 Annual Report on Form 10-K.

(2) Supply and Logistics segment profit includes interest expense (related to hedged inventory purchases) of $1 million and $4 million for the three months ended September 30, 2015 and 2014, respectively, and $4 million and $11 million for the nine months ended September 30, 2015 and 2014, respectively.

(3) The following table reconciles segment profit to net income attributable to PAGP (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Segment profit	$ 487	$ 530	$ 1,371	$ 1,627
Unallocated general and administrative expenses	—	(1)	(2)	(3)
Depreciation and amortization	(110)	(97)	(327)	(294)
Interest expense, net	(110)	(88)	(322)	(254)
Other expense, net	(4)	(4)	(7)	(2)
Income before tax	263	340	713	1,074
Income tax expense	(35)	(29)	(120)	(116)
Net income	228	311	593	958
Net income attributable to noncontrolling interests	(196)	(295)	(500)	(913)
Net income attributable to PAGP	$ 32	$ 16	$ 93	$ 45

Note 12—Related Party Transactions

See Note 15 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for a complete discussion of our related party transactions.

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Transactions with Oxy

As of September 30, 2015, Oxy owned approximately 13% of the limited partner interests in AAP and had a representative on the board of directors of GP LLC and our general partner. During the three and nine months ended September 30, 2015 and 2014, we recognized sales and transportation revenues and purchased petroleum products from Oxy. 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 those transactions is included below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues	$ 187	$ 369	$ 745	$ 812
Purchases and related costs (1)	$ (34)	$ 233	$ 112	$ 701

(1) Purchases and related costs include crude oil buy/sell transactions that are accounted for as inventory exchanges and are presented net in our Condensed Consolidated Statements of Operations.

We currently have a netting arrangement with Oxy. Our gross receivable and payable amounts with Oxy were as follows as of the dates indicated (in millions):

	September 30, 2015	December 31, 2014
Trade accounts receivable and other receivables	$ 535	$ 489
Accounts payable	$ 494	$ 441

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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 2014 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
- Acquisitions and Capital Projects
- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Forward-Looking Statements

Executive Summary

Company Overview

We are a Delaware limited partnership formed on July 17, 2013 to own an interest in the general partner and IDRs of PAA, a publicly traded Delaware limited partnership. Although we were formed as a limited partnership, we have elected to be taxed as a corporation for United States federal income tax purposes. As of September 30, 2015, we owned an approximate 37% limited partner interest in AAP, a Delaware limited partnership that directly owns all of PAA's IDRs and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP, a Delaware limited liability company that directly holds the 2% general partner interest in PAA.

Since we are the managing member of and control GP LLC, which in turn effectively controls PAA, we reflect our ownership in PAA, as well as its subsidiaries, on a consolidated basis in accordance with GAAP. Accordingly, our financial results are combined with those of GP LLC and PAA as well as with their subsidiaries. As such, our results of operations as discussed below do not differ materially from the results of operations of PAA.

PAA owns and operates midstream energy infrastructure and provides logistics services for crude oil, NGL, natural gas and refined products. PAA owns 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.

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Overview of Operating Results, Capital Investments and Other Significant Activities

For the nine months ended September 30, 2015 and 2014, we recognized net income of $593 million and $958 million, respectively. This decrease was primarily driven by less favorable results from our Supply and Logistics segment, as compressed differentials from the transitioning crude oil market and increased competition drove lower unit margins in this part of our business. In addition, our operating results for the 2015 period were impacted by costs and lost revenue associated with the Line 901 incident. See further discussion of our segment operating results in the following sections. Other items impacting net income for the first nine months of 2015 were higher depreciation and amortization expense and interest expense associated with our growing asset base and related financing activities.

We invested approximately $1.8 billion in midstream infrastructure projects during the nine months ended September 30, 2015, with a targeted expansion capital plan for the full year of 2015 of $2.2 billion. To fund such capital expansion activities, PAA executed multiple financings, including raising an aggregate of approximately $2.1 billion of long-term debt and equity capital. In addition, we paid approximately $1.2 billion of cash distributions to our Class A shareholders and noncontrolling interests during the nine months ended September 30, 2015, and we declared a quarterly distribution of $0.231 per Class A share to be paid on November 13, 2015.

Acquisitions and Capital Projects

The following table summarizes our expenditures for acquisition capital, expansion capital and maintenance capital for the periods indicated (in millions):

	Nine Months Ended September 30,	
	2015	2014
Acquisition capital (1)	$ 104	$ 10
Expansion capital (2)	1,837	1,552
Maintenance capital (2)	154	151
	$ 2,095	$ 1,713

(1) Acquisitions of initial investments or additional interests in unconsolidated entities are included in “Acquisition capital.” Subsequent contributions to unconsolidated entities related to expansion projects of such entities are recognized in “Expansion capital.”

(2) Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as expansion capital. Capital expenditures for the replacement of partially or fully depreciated assets in order to

maintain the operating and/or earnings capacity of our existing assets are classified as maintenance capital.

2015 Capital Projects

Our capital program is highlighted by a large number of small-to-medium sized projects spread across multiple geographic regions/resource plays. We believe the diversity of our program mitigates the impact of delays, cost overruns or adverse market developments with respect to a particular project or geographic region/resource play. The majority of

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our 2015 expansion capital program will be invested in our fee-based Transportation and Facilities segments. We expect that our investments will have minimal contributions to our 2015 results, but will provide growth for 2016 and beyond.

The following table summarizes our notable projects in progress during 2015 and the forecasted expenditures for the year ending December 31, 2015 (in millions):

Projects	2015
Permian Basin Area Projects	$445
Rail Terminal Projects (1)	295
Fort Saskatchewan Facility Projects / NGL Line	270
Cactus Pipeline (2)	150
Red River Pipeline (Cushing to Longview)	140
Saddlehorn Pipeline	135
Eagle Ford JV Project	80
Cowboy Pipeline (Cheyenne to Carr)	50
Eagle Ford Area Projects	45
Cushing Terminal Expansions	40
Diamond Pipeline	40
St. James Terminal Expansions	35
Line 63 Reactivation	25
Other Projects	450
	$2,200
Potential Adjustments for Timing / Scope Refinement (3)	-$100 + $100
Total Projected Expansion Capital Expenditures	$2,100 - $2,300
Maintenance Capital Expenditures	$200 - $220

(1) Includes railcar purchases and projects located in or near St. James, LA; Kerrobert, Canada; and Tampa, CO.

(2) Includes linefill costs associated with the project.

(3) Potential variation to current capital costs estimates may result from (i) changes to project design, (ii) final cost of materials and labor and (iii) timing of incurrence of costs due to uncontrollable factors such as permits, regulatory approvals and weather.

Results of Operations

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 19 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for further discussion of how we evaluate segment profit.

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

	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
	2015	2014	$	%	2015	2014	$	%
Transportation segment profit	$ 254	$ 231	$ 23	10%	$ 681	$ 658	$ 23	3%
Facilities segment profit	146	147	(1)	(1)%	432	435	(3)	(1)%
Supply and Logistics segment profit	87	152	(65)	(43)%	258	534	(276)	(52)%
Total segment profit	487	530	(43)	(8)%	1,371	1,627	(256)	(16)%
Unallocated general and administrative expenses	—	(1)	1	100%	(2)	(3)	1	33%
Depreciation and amortization	(110)	(97)	(13)	(13)%	(327)	(294)	(33)	(11)%
Interest expense, net	(110)	(88)	(22)	(25)%	(322)	(254)	(68)	(27)%
Other expense, net	(4)	(4)	—	— %	(7)	(2)	(5)	(250)%
Income tax expense	(35)	(29)	(6)	(21)%	(120)	(116)	(4)	(3)%
Net income	228	311	(83)	(27)%	593	958	(365)	(38)%
Net income attributable to noncontrolling interests	(196)	(295)	99	34%	(500)	(913)	413	45%
Net income attributable to PAGP	$ 32	$ 16	$ 16	100%	$ 93	$ 45	$ 48	107%
Basic and diluted net income per Class A share	$ 0.14	$ 0.12	$ 0.02	17%	$ 0.42	$ 0.33	$ 0.09	27%
Basic and diluted weighted average Class A shares outstanding	225	136	89	65%	220	136	84	62%

Analysis of Operating Segments

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. The Transportation segment generates revenue through a combination of tariffs, third-party pipeline capacity agreements and other transportation fees.

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The following tables set forth our operating results from our Transportation segment for the periods indicated:

Operating Results (1) (in millions, except per barrel data)	Three Months Ended September 30, 2015	2014	Favorable/ (Unfavorable) Variance $	%	Nine Months Ended September 30, 2015	2014	Favorable/ (Unfavorable) Variance $	%
Revenues								
Tariff activities	$ 364	$ 372	$ (8)	(2)%	$ 1,083	$ 1,063	$ 20	2%
Trucking	37	52	(15)	(29)%	120	159	(39)	(25)%
Total transportation revenues	401	424	(23)	(5)%	1,203	1,222	(19)	(2)%
Costs and Expenses								
Trucking costs	(26)	(38)	12	32%	(85)	(116)	31	27%
Field operating costs (2)	(147)	(153)	6	4%	(493)	(419)	(74)	(18)%
Equity-indexed compensation (expense)/benefit - operations	1	(4)	5	125%	(5)	(14)	9	64%
Segment general and administrative expenses (2) (3)	(23)	(20)	(3)	(15)%	(67)	(62)	(5)	(8)%
Equity-indexed compensation (expense)/benefit - general and administrative	3	(7)	10	143%	(6)	(26)	20	77%
Equity earnings in unconsolidated entities	45	29	16	55%	134	73	61	84%
Segment profit	$ 254	$ 231	$ 23	10%	$ 681	$ 658	$ 23	3%
Maintenance capital	$ 34	$ 35	$ 1	3%	$ 101	$ 111	$ 10	9%
Segment profit per barrel	$ 0.61	$ 0.59	$ 0.02	3%	$ 0.56	$ 0.60	$ (0.04)	(7)%

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Average Daily Volumes (in thousands of barrels per day) (4)	Three Months Ended September 30, 2015	2014	Favorable/ (Unfavorable) Variance Volumes	%	Nine Months Ended September 30, 2015	2014	Favorable/ (Unfavorable) Variance Volumes	%
Tariff activities								
Crude Oil Pipelines								
All American	—	40	(40)	(100)%	18	37	(19)	(51)%
Bakken Area Systems (5)	141	164	(23)	(14)%	146	147	(1)	(1)%
Basin / Mesa / Sunrise	815	743	72	10%	831	734	97	13%
BridgeTex	100	—	100	N/A	105	—	105	N/A
Cactus	110	—	110	N/A	58	—	58	N/A
Capline	181	178	3	2%	167	142	25	18%
Eagle Ford Area Systems (5)	321	247	74	30%	298	215	83	39%
Line 63 / Line 2000	121	126	(5)	(4)%	121	119	2	2%
Manito	43	44	(1)	(2)%	48	44	4	9%
Mid-Continent Area Systems	342	354	(12)	(3)%	356	350	6	2%
Permian Basin Area Systems	860	776	84	11%	817	765	52	7%
Rainbow	109	104	5	5%	114	111	3	3%
Rangeland	58	61	(3)	(5)%	59	65	(6)	(9)%
Salt Lake City Area Systems (5)	155	140	15	11%	136	134	2	1%
South Saskatchewan	59	62	(3)	(5)%	62	61	1	2%
White Cliffs	41	33	8	24%	43	27	16	59%
Other	777	823	(46)	(6)%	752	737	15	2%
NGL Pipelines								
Co-Ed	51	57	(6)	(11)%	56	56	—	— %
Other	149	143	6	4%	139	127	12	9%
Tariff activities total	4,433	4,095	338	8%	4,326	3,871	455	12%
Trucking	112	131	(19)	(15)%	114	129	(15)	(12)%
Transportation segment total	4,545	4,226	319	8%	4,440	4,000	440	11%

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

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) 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.

(4) Volumes associated with assets employed through acquisitions and capital expansion projects represent total volumes (attributable to our interest) for the number of days we employed the assets divided by the number of days in the period.

(5) Area systems include volumes (attributable to our interest) from our investments in unconsolidated entities.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Revenue from our pipeline capacity agreements generally reflects a negotiated amount. Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month.

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The following is a discussion of items impacting Transportation segment profit and segment profit per barrel for the periods indicated.

Net Operating Revenues and Volumes. As reflected in the tables above, our total Transportation segment revenues, net of trucking costs, increased by $12 million for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014, but decreased by $11 million for the three months ended September 30, 2015 compared to three months ended September 30, 2014. Average daily volumes increased for each of the comparative periods presented. Our Transportation segment results were impacted by the following:

- North American Crude Oil Production and Related Expansion Projects — Production growth from the development of certain North American crude oil resource plays increased throughput on our existing pipeline systems over the comparative periods presented. Additionally, we have recently completed infrastructure projects related to production growth that have generated incremental volumes through increased capacity and connections. We estimate that the impact of increased throughput, most notably on our Eagle Ford Area Systems and certain pipelines in our Permian Basin Area Systems, and incremental volumes from our recently constructed infrastructure projects, including our Cactus and Sunrise pipelines, increased our revenues by $10 million and $55 million, respectively, for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014.

- Tariff Rates — Revenues on our pipelines are impacted by various tariff rate changes that may occur during the period, which include (i) rate increases or decreases on our intrastate and Canadian pipelines and fees on related system assets, (ii) the indexing of rates on our FERC regulated pipelines or (iii) other negotiated rate changes. We estimate that the net impact of such rate changes on our pipelines increased revenues by $15 million and $45 million for the three and nine months ended September 30, 2015, respectively, compared to the three and nine months ended September 30, 2014 primarily due to tariff rate increases on certain of our Canadian crude oil pipelines and incremental fees on related system assets, and, to a lesser extent, indexing on our FERC regulated pipelines and rate increases on our intrastate pipelines.

- Foreign Exchange Impact — We estimate that tariff revenues from our Canadian pipeline systems and net revenues from our Canadian trucking operations were unfavorably impacted by $18 million and $39 million for the three and nine months ended September 30, 2015, respectively, compared to the three and nine months ended September 30, 2014 due to the depreciation of CAD relative to USD.

- Loss Allowance Revenue — As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The loss allowance revenue decreased by $11 million and $38 million, respectively, for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014 primarily due to a lower average realized price per barrel, partially offset by higher volumes.

- All American Pipeline — As a result of pipeline downtime associated with the Line 901 incident that occurred in the second quarter of 2015, tariff revenues from our All American pipeline were $9 million and $12 million lower for the three and nine months ended September 30, 2015, respectively, compared to the three and nine months ended September 30, 2014. See Note 10 to our Condensed Consolidated Financial Statements for additional information regarding this incident.

Additional noteworthy volume and revenue variances for the comparative periods presented included (i) decreased volumes and revenues from our trucking operations due to lower producer volumes, (ii) lower volumes and revenues on our San Joaquin Valley gathering system due to refinery outages, (iii) lower volumes on our Pascagoula pipeline during the third quarter of 2015 due to downtime for pipeline and refinery maintenance and (iv) increased

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volumes and revenues on the Capline Pipeline System for the nine-month comparative period due to higher refinery demand and timing of a refinery turnaround, which occurred in the second quarter of 2014.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 primarily due to a favorable foreign exchange impact of $7 million.

Field operating costs (excluding equity-indexed compensation expense) increased for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 primarily due to estimated costs of $65 million recognized during the second quarter of 2015 associated with the Line 901 incident, net of amounts we believe are probable of recovery from insurance. See Note 10 to our Condensed Consolidated Financial Statements for additional information regarding this incident. The nine-month 2015 period was also impacted by higher salary and related expenses and property tax expense primarily associated with the growth and capital expansion in the segment, partially offset by favorable foreign exchange impacts of $16 million.

General and Administrative Expenses. The increase in general and administrative expenses (excluding equity-indexed compensation expense) for the three and nine months ended September 30, 2015 over the comparable 2014 periods was primarily due to increased salaries, benefits and other costs associated with the growth in the segment.

Equity-Indexed Compensation Expense. On a consolidated basis across all segments, equity-indexed compensation expense decreased for the three and nine months ended September 30, 2015 compared to the same periods in 2014 primarily due to the impact of the decrease in PAA’s unit price during each of the 2015 periods compared to the impact of the change in PAA’s unit price during the 2014 periods.

Allocations of equity-indexed compensation expense vary over time (i) between field operating costs and general and administrative expenses and (ii) between segments and could result in variances in those expense categories or segments that differ from the consolidated variance explanations above. See Note 16 to our Consolidated Financial Statements included in Part IV of our 2014 Annual Report on Form 10-K for additional information regarding our equity-indexed compensation plans.

Equity Earnings in Unconsolidated Entities. The favorable variance in equity earnings in unconsolidated entities for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014 was primarily driven by (i) earnings from our 50% interest in BridgeTex, which we acquired in November 2014, and (ii) increased throughput on the Eagle Ford pipeline as a result of increased crude oil production in that region, as discussed in “Net Operating Revenues and Volumes” above. The nine-month comparative period was further favorably impacted by increased throughput on the White Cliffs pipeline due to an expansion of the pipeline that was placed into service in July 2014.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The decrease in maintenance capital for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 was primarily due to a reclassification of certain maintenance capital costs from our Facilities segment during the 2014 period. In addition, increased spending on integrity and repair activities was largely offset by the impact of the depreciation of CAD relative to USD.

Facilities Segment

Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. The Facilities segment generates revenue through a combination of month-to-month and multi-year agreements and processing arrangements. Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month.

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The following tables set forth our operating results from our Facilities segment for the periods indicated:

perating Results (1)	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
n millions, except per barrel data)	2015	2014	$	%	2015	2014	$	%
evenues	$ 263	$ 281	$ (18)	(6)%	$ 789	$ 858	$ (69)	(8)%
atural gas related storage costs	(7)	(9)	2	22%	(17)	(47)	30	64%
eld operating costs (2)	(96)	(104)	8	8%	(284)	(307)	23	7%
quity-indexed compensation xpense)/benefit - operations	1	(1)	2	200%	(1)	(4)	3	75%
egment general and administrative xpenses (2) (3)	(17)	(16)	(1)	(6)%	(50)	(46)	(4)	(9)%
quity-indexed compensation xpense)/benefit - general and dministrative	2	(4)	6	150%	(5)	(19)	14	74%
egment profit	$ 146	$ 147	$ (1)	(1)%	$ 432	$ 435	$ (3)	(1)%
aintenance capital	$ 16	$ 19	$ 3	16%	$ 48	$ 34	$ (14)	(41)%
egment profit per barrel	$ 0.39	$ 0.40	$ (0.01)	(3)%	$ 0.38	$ 0.40	$ (0.02)	(5)%

olumes (4)	Three Months Ended September 30, 2015	2014	Favorable/ (Unfavorable) Variance Volumes	%	Nine Months Ended September 30, 2015	2014	Favorable/ (Unfavorable) Variance Volumes	%
rude oil, refined products and GL terminalling and storage verage monthly capacity in illions of barrels)	100	95	5	5%	99	95	4	4%
ail load / unload volumes (average olumes in thousands of barrels per ay)	231	241	(10)	(4)%	223	232	(9)	(4)%
atural gas storage (average onthly working capacity in llions of cubic feet)	97	97	—	— %	97	97	—	— %
GL fractionation (average olumes in thousands of barrels per ay)	98	104	(6)	(6)%	101	94	7	7%
acilities segment total (average onthly volumes in millions of arrels) (5)	126	121	5	4%	126	121	5	4%

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

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) 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.

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(4) Volumes associated with assets employed through acquisitions and capital expansion projects represent total volumes for the number of months we employed the assets divided by the number of months in the period.

(5) Facilities segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the period and divided by the number of months in the period; (iii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

The following is a discussion of items impacting Facilities segment profit and segment profit per barrel for the periods indicated.

Net Operating Revenues and Volumes. As noted in the table above, our Facilities segment revenues, less storage related costs, decreased by $16 million and $39 million for the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014, while total volumes for each of the comparative periods presented increased. Our Facilities segment results for the comparative periods were impacted by:

- Rail Terminals — For the three and nine months ended September 30, 2015, revenues from our rail activities decreased by $6 million and $16 million, respectively, due to lower volumes and lower rail fees related to the movement of certain volumes of Bakken crude oil, partially offset by revenues from our Bakersfield rail terminal that came online in the fourth quarter of 2014.

- Natural Gas Storage — Net revenues from our natural gas storage activities decreased by $5 million and $9 million for the three and nine month comparative periods, respectively, primarily due to declines in market rates for natural gas storage during the 2015 periods resulting in lower rates on new contracts replacing expiring contracts and reduced hub services opportunities.

- Gulf Coast Gas Processing — Revenues from our Gulf Coast gas processing activities decreased by $3 million and $10 million for the three and nine months ended September 30, 2015, respectively, compared to the three and nine months ended September 30, 2014, primarily due to lower volumes and decreased margins driven by lower commodity prices.

- NGL Storage, NGL Fractionation and Canadian Gas Processing — Revenues from our NGL storage, NGL fractionation and Canadian gas processing activities decreased by $3 million and $7 million for the three and nine month comparative periods presented, respectively. Such decreases were primarily due to unfavorable foreign currency impacts of $13 million and $30 million for the three and nine month comparative periods, respectively, due to the depreciation of CAD relative to USD, which offset revenue increases from higher facility fees for the 2015 periods. These impacts were largely offset in our Supply and Logistics segment results. The nine-month comparative period was further unfavorably impacted by lower physical processing gains related to component mix at our

fractionation facilities and significantly lower NGL prices during 2015.

NGL fractionation volumes increased for the nine-month comparative period due to higher NGL supply volumes from western Canada; however, volumes decreased for the three-month comparative period due to a facility outage. Such volume variances did not have a corresponding impact on revenue as the impacted facilities charge a fixed monthly fee.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014 primarily due to a decrease in maintenance and repair costs and favorable foreign exchange impacts of $6 million and $15 million for the three and nine month comparative periods, respectively, partially offset by higher salary and related expenses. In addition, the nine month 2015 period was impacted by lower gas and power costs largely associated with our NGL fractionation and Canadian natural gas processing activities.

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Maintenance Capital. The decrease in maintenance capital for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 was primarily due to timing of tank and facility projects.

The increase in maintenance capital for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 was primarily due to various tank and facility projects and timing of equipment replacements. The nine month comparative period was also impacted by a change in classification of certain maintenance capital costs to our Transportation segment in the second quarter of 2014.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers and natural gas sales attributable to the activities performed by our natural gas storage commercial optimization group. Generally, we expect our segment profit to increase or decrease directionally with (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchase volumes and NGL sales volumes), (ii) demand for lease gathering services we provide producers and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. We do not anticipate that future changes in revenues resulting from variances in commodity prices will be a primary driver of segment profit.

The following tables set forth our operating results from our Supply and Logistics segment for the periods indicated:

perating Results (1)	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
n millions, except per barrel data)	2015	2014	$	%	2015	2014	$	%
evenues	$ 5,254	$ 10,793	$ (5,539)	(51)%	$ 17,238	$ 33,021	$ (15,783)	(48)%
urchases and related costs (2)	(5,032)	(10,488)	5,456	52%	(16,553)	(32,041)	15,488	48%
ield operating costs (3)	(110)	(122)	12	10%	(338)	(340)	2	1%
quity-indexed compensation xpense - operations	—	—	—	— %	—	(2)	2	100%
egment general and administrative xpenses (3) (4)	(26)	(25)	(1)	(4)%	(79)	(79)	—	— %
quity-indexed compensation xpense)/benefit - general and dministrative	1	(6)	7	117%	(10)	(25)	15	60%
egment profit	$ 87	$ 152	$ (65)	(43)%	$ 258	$ 534	$ (276)	(52)%
laintenance capital	$ 2	$ 2	$ —	— %	$ 5	$ 6	$ 1	17%

egment profit per barrel	$ 0.84	$ 1.47	$ (0.63)	(43)%	$ 0.81	$ 1.75	$ (0.94)	(54)%

verage Daily Volumes	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
n thousands of barrels per day)	2015	2014	Volume	%	2015	2014	Volume	%
rude oil lease gathering purchases	927	971	(44)	(5)%	958	932	26	3%
GL sales	183	153	30	20%	209	188	21	11%
Vaterborne cargos	4	—	4	N/A	1	—	1	N/A
upply and Logistics segment total	1,114	1,124	(10)	(1)%	1,168	1,120	48	4%

(1) Revenues and costs include intersegment amounts.

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(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of $1 million and $4 million for the three months ended September 30, 2015 and 2014, respectively, and $4 million and $11 million for the nine months ended September 30, 2015 and 2014, respectively.

(3) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(4) 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.

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

	NYMEX WTI Crude Oil Price	
	Low	High
Three months ended September 30, 2015	$ 38	$ 57
Three months ended September 30, 2014	$ 90	$ 106
Nine months ended September 30, 2015	$ 38	$ 61
Nine months ended September 30, 2014	$ 90	$ 108

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases decreased for the three and nine months ended September 30, 2015 due to lower crude oil and NGL prices relative to the comparative 2014 periods.

Generally, we expect a base level of earnings from our Supply and Logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. Also, 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.

The following is a discussion of items impacting Supply and Logistics segment profit and segment profit per barrel for the periods indicated.

Net Operating Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs, decreased by $83 million and $295 million for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014, respectively. The following summarizes the more significant items in the comparative periods:

· Crude Oil Operations — Net revenues from our crude oil supply and logistics activities decreased for the three and nine months ended September 30, 2015 as compared to the same periods in 2014 primarily due to the compression of certain differentials during the 2015 periods, which resulted in fewer opportunities to capture above-baseline margins as compared to 2014. Additionally, lease gathering volumes and unit margins were negatively impacted by increased competition, most notably during the three-month comparative periods. However, such unfavorable results were partially offset by revenues from opportunities created by the contango market structure during the 2015 periods.

· NGL Operations — Net revenues from our NGL operations increased for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014. These increases were

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primarily driven by (i) higher sales volumes and (ii) higher margins due to strong demand and lower supply costs in the summer months.

· Natural Gas Storage Commercial Optimization — During the first quarter of 2014, our natural gas storage commercial optimization activities were unfavorably impacted by costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather. We did not incur similar costs during 2015.

· Impact from Certain Derivative Activities, Net of Inventory Valuation Adjustments — The mark-to-market of certain of our derivative activities impacted our net revenues as shown in the table below for the periods indicated (in millions):

	Three Months Ended September 30,		Variance		Nine Months Ended September 30,		Variance	
	2015	2014	$	%	2015	2014	$	%
Gains/(losses) from certain derivative activities net of inventory valuation adjustments (1)	$ 43	$ 29	$ 14	48%	$ (116)	$ 81	$ (197)	(243)%

(1) Includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in another period (or the reversal of mark-to-market gains and losses from a prior period), gains and losses on certain derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable. See Note 8 to our Condensed Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

· Long-Term Inventory Costing Adjustments — Our operating results are impacted by changes in the weighted average cost of our crude oil and NGL inventory pools that result from price movements during the periods. Such costing adjustments resulted in unfavorable impacts of $47 million and $62 million for the three and nine months ended September 30, 2015, respectively, due to price decreases during such periods. These costing adjustments related to long-term inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that was needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future.

· Foreign Exchange — During 2015, there were fluctuations in the value of CAD to USD, resulting in net foreign exchange gains on U.S. denominated net assets within our Canadian operations of approximately $30 million for the nine months ended September 30, 2015. Our results were also favorably impacted by approximately $13 million and $26 million for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014, respectively, due to the depreciation of CAD relative to USD. This resulted in lower net USD costs that were primarily associated with intercompany facility fees and were largely offset in our Facilities segment results.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 and was relatively consistent for the nine month comparative periods. The decrease for the three month comparative periods was primarily due to lower trucking costs resulting from decreased lease gathering volumes.

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Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense increased for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014, primarily due to various internal growth projects completed since September 30, 2014.

Interest Expense

The increase in interest expense for the three and nine months ended September 30, 2015 over the three and nine months ended September 30, 2014 was due to a higher weighted average debt balance driven by PAA senior notes issuances in April, September and December of 2014 for an aggregate of $2.6 billion, as well as $1.0 billion of PAA senior notes issued in August 2015. The impact of the higher weighted average debt balance was partially offset by a favorable impact from lower weighted average interest rates on these senior notes issuances.

Income Tax Expense

Income tax expense increased for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014 primarily due to higher deferred income tax expense associated with the amortization of our deferred tax asset, an Alberta, Canada provincial tax rate increase of 2% enacted during the second quarter of 2015, as well as higher current income tax expense resulting from increased year-over-year taxable earnings from our Canadian operations. This increase was partially offset by the deferred income tax impact associated with fluctuations in the derivative mark-to-market valuation in our Canadian operations during the periods and the depreciation of CAD relative to USD.

Outlook

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays, which occurred contemporaneously with attractive crude oil and liquids prices, during the approximately three year period through the end of 2014, U.S. crude oil and liquids production in the lower 48 states increased rapidly. This was particularly true for light crudes and condensates. Similar resource development activities in Canada and ongoing oil sands development activities also led to increased Canadian crude oil production during

this period. Additionally, during this period, the crude oil market experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude oil qualities, international supply issues, and regional downstream operating issues. During 2013 and to a lesser degree 2014, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment.

However, the combination during such period of surging North American liquids production, relatively flat liquids production for the rest of the world and relatively modest growth in global liquids demand led to a supply imbalance, which in turn led to a significant and rapid reduction in petroleum prices. Additionally, the slowdown in North American production coupled with an increase in new infrastructure has led to a compression of basis differentials in a number of locations. While we believe that our business model and asset base have minimal direct exposure to petroleum prices, our performance is influenced by certain differentials and overall North American production levels, which in turn are impacted by major price movements. The meaningful decrease in crude oil price levels during the second half of 2014 and the first three quarters of 2015 relative to the levels experienced during 2013 and the first half of 2014 have led many producers, including producers that impact North American production levels, to significantly scale back capital programs. As a result, during the first three quarters of 2015, the rate of growth of North American crude oil production has slowed significantly and began to decrease in some areas as producers have taken rigs out of service and deferred completions at an increased rate. While we believe that the large North American resource base remains intact and will be developed, such production will likely take place at a slower pace and previously anticipated peak production levels will likely be reduced. This transitioning crude oil market may present challenges to our business model and asset base and may impact the rate of cash flow and distribution growth that we would have otherwise

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experienced over the next several years. In addition, increased competition and compressed differentials may drive lower volumes and lower unit margins in parts of our business, including our Supply and Logistics segment.

While we believe that these recent market developments will continue to slow down crude oil supply growth and contribute toward bringing the markets back to equilibrium, there can be no assurance that such equilibrium will be achieved or that we will not be negatively impacted by declining crude oil supply, unfavorable volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely create excess takeaway capacity in certain areas at least for the near to medium term, which could further reduce unit margins in our various segments, and underutilization of midstream assets resulting from continued production declines could have a similar unfavorable impact on volumes and unit margins. Finally, we cannot be certain that our expansion efforts will generate targeted returns or that any future acquisition activities will be successful. See “Risk Factors—Risks Related to PAA’s Business” discussed in Item 1A of our 2014 Annual Report on Form 10-K.

Liquidity and Capital Resources

General

On a consolidated basis, our primary sources of liquidity are (i) cash flow from operating activities, (ii) borrowings under credit facilities or the PAA commercial paper program and (iii) funds received from PAA’s 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 and other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on long-term debt and (v) distributions to our Class A shareholders and noncontrolling interests. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under the PAA commercial paper program or the credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional PAA equity or debt securities. As of September 30, 2015, we had a working capital deficit of $519 million and approximately $3.2 billion of liquidity available to meet our ongoing operating, investing and financing needs as noted below (in millions):

	As of September 30, 2015

Availability under PAA senior unsecured revolving credit facility (1) (2)	$	1,585
Availability under PAA senior secured hedged inventory facility (1) (2)		1,371
Availability under PAA senior unsecured 364-day revolving credit facility		1,000
Amounts outstanding under PAA commercial paper program		(886)
Subtotal		3,070
Availability under AAP senior secured revolving credit facility		116
Cash and cash equivalents		25
Total	$	3,211

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

(2) Available capacity under the senior unsecured revolving credit facility and the senior secured hedged inventory facility was reduced by outstanding letters of credit of $15 million and $29 million, respectively.

We believe that we have, and will continue to have, the ability to access the PAA 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 liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A “Risk Factors” of our 2014 Annual Report on Form 10-K for further

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discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities, certain of which provide the backstop for the PAA commercial paper program, is subject to ongoing compliance with covenants. As of September 30, 2015, PAA and AAP were in compliance with all such covenants.

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 “Liquidity and Capital Resources—Cash Flow from Operating Activities” under Item 7 of our 2014 Annual Report on Form 10-K.

Net cash provided by operating activities for the first nine months of 2015 and 2014 was approximately $1.2 billion and $1.3 billion, respectively, and primarily resulted from earnings from our operations.

Acquisitions and Capital Expenditures

In addition to operating needs discussed above, we also use cash for our acquisition activities and capital projects. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital.

2015 Capital Projects. See “—Acquisitions and Capital Projects” for detail of our projected capital expenditures for the year ending December 31, 2015. A majority of the funding for our 2015 capital program has been provided by borrowings under the PAA commercial paper program as well as through proceeds received from PAA’s March 2015 underwritten equity offering and PAA’s August 2015 debt offering.

Equity and Debt Financing Activities

On a consolidated basis, our financing activities primarily relate to funding acquisitions, expansion capital projects and refinancing of debt maturities, as well as short-term working capital and hedged inventory borrowings related to our NGL business and contango market activities. Our financing activities have primarily consisted of PAA equity offerings, PAA senior notes offerings and borrowings and repayments under credit facilities or the PAA commercial paper program, as well as payment of distributions to our Class A shareholders and noncontrolling interests.

PAA Registration Statements. PAA periodically accesses the capital markets for both equity and debt financing. PAA has filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows PAA to issue up to an aggregate of $2.0 billion of debt or equity securities ("Traditional Shelf"). All issuances of PAA equity securities associated with PAA's continuous offering program, as discussed further below, have been issued pursuant to the Traditional Shelf. As of November 5, 2015, PAA had $2.0 billion of unsold securities available under the Traditional Shelf. PAA also has access to a universal shelf registration statement ("WKSI Shelf"), which provides it with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and capital needs. PAA's March 2015 underwritten equity offering and the issuance of $1.0 billion, 4.65% PAA senior notes in August 2015, as discussed further below, were conducted under PAA's WKSI Shelf.

PAA Continuous Offering Program. During the nine months ended September 30, 2015, PAA issued an aggregate of approximately 1.1 million common units under its continuous offering program, generating proceeds of $58 million. The net proceeds from sales were used for general partnership purposes.

Underwritten Offering. In March 2015, PAA completed an underwritten public offering of 21.0 million common units generating net proceeds of approximately $1.0 billion, net of costs associated with the offering. We used a portion of the net proceeds from this offering to repay outstanding borrowings under PAA's commercial paper program and we used the remaining net proceeds for general partnership purposes, including expenditures for our 2015 capital program.

Credit Agreements, Commercial Paper Program and Indentures. The PAA credit agreements (which impact the ability to access the PAA commercial paper program because they provide the backstop that supports PAA's short-term

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credit ratings), the AAP credit agreement and the indentures governing PAA's senior notes contain cross-default provisions. A default under the credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as PAA and AAP are in compliance with the provisions in the credit agreements, their ability to make distributions of available cash is not restricted. PAA and AAP were in compliance with the covenants contained in the credit agreements and indentures as of September 30, 2015.

During the nine months ended September 30, 2015, we had net borrowings under credit agreements and the PAA commercial paper program of $174 million. Borrowings resulted primarily from funding needs for (i) internal capital projects, (ii) repayment of the PAA senior notes that matured during 2015 and (iii) other general partnership purposes, and were partially offset by repayments from cash received from PAA's debt and equity activities.

During the nine months ended September 30, 2014, we had net repayments under credit agreements and the PAA commercial paper program of $667 million. The net repayments resulted primarily from cash flow from operating activities, as well as cash received from PAA's debt and equity activities.

In January 2015, PAA entered into a new agreement for a $1.0 billion, 364-day senior unsecured revolving credit facility. Borrowings, if any, accrue interest based, at PAA's election, on either the Eurocurrency Rate or the Base Rate, as defined in the agreement, in each case plus a margin based on PAA's credit rating at the applicable time. In August 2015, PAA amended the agreement to extend the maturity date to August 2016.

In August 2015, PAA extended the maturity dates of its senior secured hedged inventory facility and its senior unsecured revolving credit facility by one year to August 2018 and August 2020, respectively.

In August 2015, AAP amended its credit agreement to, among other things, (i) increase its term loan commitments from $500 million to $550 million, (ii) increase the aggregate commitments under its senior secured revolving credit facility from $75 million to $125 million and (iii) extend the maturity date of the term loan and senior secured revolving credit facility to August 2020. In addition, the amendment provides for a $50 million accordion feature, which may be used to expand the term loan and/or revolving credit facility commitments.

In August 2015, PAA completed the issuance of $1.0 billion, 4.65% senior notes due 2025 at a public offering price of 99.846%. Interest payments are due on April 15 and October 15 of each year, commencing on April 15, 2016. PAA used the net proceeds from this offering of $990 million, after deducting the underwriting discount and offering expenses, to repay outstanding borrowings under the PAA commercial paper program and for general partnership purposes.

As mentioned above, in June 2015 and September 2015, PAA's $150 million, 5.25% senior notes and $400 million, 3.95% senior notes, respectively, matured and were repaid with cash on hand and proceeds from borrowings under the PAA commercial paper program.

PAA's $175 million, 5.88% senior notes will mature in August 2016. We intend to use borrowings under the PAA commercial paper program to repay these senior notes when they mature.

Distributions Paid to Our Class A Shareholders and Noncontrolling Interests

Distributions to our Class A shareholders. We distribute 100% of our available cash within 55 days following the end of each quarter to Class A shareholders of record. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On November 13, 2015, we will pay a quarterly distribution of $0.231 per Class A share. This distribution represents a year-over-year distribution increase of approximately 21.1%. See Note 7 to our Condensed Consolidated Financial Statements for details of distributions paid. Also, see Item 5. "Market for Registrant's Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy" included in our 2014 Annual Report on Form 10-K for additional discussion regarding distributions.

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Distributions to noncontrolling interests. Distributions to noncontrolling interests represent amounts paid on interests in consolidated entities that are not owned by us. During the nine months ended September 30, 2015 and 2014, we paid distributions of approximately $1.1 billion and $959 million, respectively, to noncontrolling interests.

We believe that we have sufficient liquid assets, cash flow from operating activities and borrowing capacity under 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. A prolonged material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

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

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to ten 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. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with our counterparties (including giving effect to netting buy/sell contracts and those subject to a net settlement arrangement). We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of September 30, 2015 (in millions):

2020 and

	Remainder of 2015	2016	2017	2018	2019	Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 330	$ 661	$ 857	$ 1,030	$ 1,245	$ 12,441	$ 16,564
Leases (2)	48	188	171	149	124	527	1,207
Other obligations (3)	127	386	100	51	39	171	874
Subtotal	505	1,235	1,128	1,230	1,408	13,139	18,645
Crude oil, natural gas, NGL and other purchases (4)	2,006	3,622	2,566	1,837	1,272	4,082	15,385
Total	$ 2,511	$ 4,857	$ 3,694	$ 3,067	$ 2,680	$ 17,221	$ 34,030

(1) Includes debt service payments, interest payments due on PAA's senior notes, interest payments on long-term borrowings outstanding under the AAP credit agreement, the commitment fee on assumed available capacity under the PAA revolving credit facilities and long-term borrowings under the PAA commercial paper program. Although there may be short-term borrowings under the PAA revolving credit facilities and the PAA commercial paper program, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the facilities or the PAA commercial paper program) in the amounts above.

(2) Leases are primarily for (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars. Includes both capital and operating leases as defined by FASB guidance.

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(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements and (iii) non-cancelable commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity-method investments. Excludes a non-current liability of approximately $39 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during September 2015. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs, derivative transactions and construction activities. At September 30, 2015 and December 31, 2014, we had outstanding letters of credit of approximately $44 million and $87 million, respectively.

Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Item 7 of our 2014 Annual Report on Form 10-K.

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” a “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:

- our ability to pay distributions to our Class A shareholders;

- our expected receipt of, and amounts of, distributions from Plains AAP, L.P.;

- failure to implement or capitalize, or delays in implementing or capitalizing, on planned growth projects;

- declines in the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets, whether due to declines in production from existing oil and gas reserves, failure to develop or slowdown in the development of additional oil and gas reserves, whether from reduced cash flow to fund drilling or the inability to access capital, or other factors;

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- the effects of competition;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the currency exchange rate of the Canadian dollar;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- maintenance of PAA's credit rating and ability to receive open credit from suppliers and trade counterparties;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from historical operations;
- increased costs, or lack of availability, of insurance;
- non-utilization of our assets and facilities;

- the effectiveness of our risk management activities;

- shortages or cost increases of supplies, materials or labor;

- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;

- fluctuations in the debt and equity markets, including the price of PAA's units at the time of vesting under its long-term incentive plans;

- risks related to the development and operation of our assets, including our ability to satisfy our contractual obligations to our customers;

- 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;

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- factors affecting demand for natural gas and natural gas storage services and rates;

- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and

- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

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 2014 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

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

- Crude oil

We utilize crude oil derivatives to hedge commodity price risk inherent in our Supply and Logistics and Transportation segments. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory, and storage capacity utilization. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

· Natural gas

We utilize natural gas derivatives to hedge commodity price risk inherent in our Supply and Logistics and Facilities segments. Our objectives for these derivatives include hedging anticipated purchases and sales and managing our anticipated base gas requirements. We manage these exposures with various instruments including exchange-traded futures, swaps and options.

· NGL and other

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

See Note 8 to our Condensed Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

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Our policy is to (i) purchase only product for which we have a market, (ii) hedge our purchase and sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or other derivative instruments for the purpose of speculating on outright commodity price changes, as these activities could expose us to significant losses.

The fair value of our commodity derivatives and the change in fair value as of September 30, 2015 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	$ 105	$ (28)	$ 28
Natural gas	(4)	$ (2)	$ 2
NGL and other	82	$ (33)	$ 33
Total fair value	$ 183		

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

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time we use interest rate derivatives to hedge interest rate risk associated with anticipated interest payments and, in certain cases, outstanding debt instruments. All of PAA's senior notes are fixed rate notes and thus are not subject to interest rate risk. The majority of our variable rate debt at September 30, 2015, approximately $1.4 billion, is subject to interest rate re-sets, which range from one day to one month. The average interest rate on variable rate debt that was outstanding during the nine months ended September 30, 2015 was 1.2%, based upon rates in effect during such period. The fair value of our interest rate derivatives was a liability of $57 million as of September 30, 2015. A 10% increase in the forward LIBOR curve as of September 30, 2015 would have resulted in an increase of $46 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of September 30, 2015 would have resulted in a decrease of $46 million to the fair value of our interest rate derivatives. See Note 8 to our Condensed Consolidated Financial Statements for a discussion of our interest rate risk hedging

activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives was a liability of $9 million as of September 30, 2015. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in a decrease of $17 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in an increase of $17 million to the fair value of our foreign currency derivatives. See Note 8 to our Condensed Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

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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, 2015, 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 2015 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.

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PART II. OTHER INFORMATION

Item 1.LEGAL PROCEEDINGS

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

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2014 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

In connection with our IPO and related transactions, the former owners of Plains All American GP LLC (the “Legacy Owners”) acquired the following interests (collectively, the “Stapled Interests”): (i) AAP units representing an economic limited partner interest in AAP; (ii) general partner units representing a non-economic membership interest in our general partner; and (iii) Class B shares representing a non-economic limited partner interest in us. The Legacy Owners and any permitted transferees of their Stapled Interests have the right to exchange (the “Exchange Right”) all or a portion of such Stapled Interests for an equivalent number of Class A shares. In connection with the exercise of the Exchange Right, the Stapled Interests are transferred to us and the applicable Class B shares are canceled. Although we issue one Class A share for each Stapled Interest that is exchanged, we also receive one AAP unit and one general partner unit. As a result, the exercise by Legacy Owners of the Exchange Right is not dilutive. During the three months ended September 30, 2015, certain Legacy Owners or their permitted transferees exercised the Exchange Right, which resulted in the issuance of 2,892,505 Class A shares. The issuance of Class A shares in connection with the exercise of the Exchange Rights was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof.

Item 3.DEFAULTS UPON SENIOR SECURITIES

None.

Item 4.MINE SAFETY DISCLOSURES

None.

Item 5.OTHER INFORMATION

None.

Item 6.EXHIBITS

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 GP HOLDINGS, L.P.

By: PAA GP HOLDINGS LLC,
its general partner

By: /s/ Greg L. Armstrong
Greg L. Armstrong,

Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)

November 6, 2015

By: /s/ Al Swanson
Al Swanson,
Executive Vice President and Chief Financial Officer (Principal Financial Officer)

November 6, 2015

By: /s/ Chris Herbold
Chris Herbold,

Vice President —Accounting and Chief Accounting Officer (Principal Accounting Officer)

November 6, 2015

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EXHIBIT INDEX

3.1	—	Certificate of Limited Partnership of Plains GP Holdings, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1 (333-190227) filed July 29, 2013).
3.2	—	Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P. dated as of October 21, 2013 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 25, 2013).
3.3	—	Certificate of Formation of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1 (333-190227) filed July 29, 2013).
3.4	—	Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC dated as of October 21, 2013 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed October 25, 2013).
3.5	—	Amendment No. 1 dated as of December 31, 2013 to the Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed December 31, 2013).
3.6	—	Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of May 17, 2012 (incorporated by reference to Exhibit 3.1 to PAA's Current Report on Form 8-K filed May 23, 2012).
3.7	—	Amendment No. 1 dated October 1, 2012 to the Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to PAA's Current Report on Form 8-K filed October 2, 2012).
3.8	—	Amendment No. 2 dated December 31, 2013 to the Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed December 31, 2013).
3.9	—	Amendment No. 3 dated May 15, 2015 to the Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to PAA's Current Report on Form 8-K filed May 15, 2015).
3.10	—	Sixth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated October 21, 2013 (incorporated by reference to Exhibit 3.4 to our Current Report on Form 8-K filed October 25, 2013).
3.11	—	Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated October 21, 2013 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed October 25, 2013).
3.12	—	Amendment No. 1 dated December 31, 2013 to Seventh 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 December 31, 2013).

3.13 — Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to PAA's Current Report on Form 8-K filed January 4, 2008).

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 PAA's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).

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4.2 — Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 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 4.5 to PAA's Registration Statement on Form S-4, File No. 333-121168).

4.3 — 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 PAA's Current Report on Form 8-K filed May 12, 2006).

4.4 — Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) 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 4.1 to PAA's Current Report on Form 8-K filed October 30, 2006).

4.5 — 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 PAA's Current Report on Form 8-K filed October 30, 2006).

4.6 — Thirteenth Supplemental Indenture (Series A and Series B 6.50% Senior Notes due 2018) dated April 23, 2008 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 4.1 to PAA's Current Report on Form 8-K filed April 23, 2008).

4.7 — Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 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 4.1 to PAA's Current Report on Form 8-K filed April 20, 2009).

4.8 — Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 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 4.1 to PAA's Current Report on Form 8-K filed September 4, 2009).

4.9 — Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 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 4.1 to PAA's Current Report on Form 8-K filed January 11, 2011).

4.10 — Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to PAA's Current Report on Form 8-K filed March 26, 2012).

4.11 — 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 PAA's Current Report on Form 8-K filed March 26, 2012).

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4.12 — Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to PAA's Current Report on Form 8-K filed December 12, 2012).

4.13 — 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 PAA's Current Report on Form 8-K filed December 12, 2012).

4.14 — 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 PAA's Current Report on Form 8-K filed August 15, 2013).

4.15 — 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).

4.16 — 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).

4.17 — Twenty-Seventh Supplemental Indenture (2.60% Senior Notes due 2019) 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 4.1 to our Current Report on Form 8-K filed December 11, 2014).

4.18 — 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).

4.19 — 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 PAA's Current Report on Form 8-K filed August 26, 2015).

4.20 — Shareholder and Registration Rights Agreement dated October 21, 2013 by and among Plains GP Holdings, L.P. and the other parties signatory thereto (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed October 25, 2013).

4.21 — 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 PAA's Registration Statement on Form S-3, File No. 333-162477).

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10.1	—	364-Day Credit Agreement dated January 16, 2015 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; Citibank, N.A., JPMorgan Chase Bank N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents; DNB Bank ASA, New York Branch and Mizuho Bank, Ltd., as Co-Documentation Agents; the other Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 20, 2015).
10.2	—	First Amendment to 364-Day Credit Agreement dated August 14, 2015 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; Citibank, N.A., JPMorgan Chase Bank N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents; DNB Bank ASA, New York Branch and Mizuho Bank, Ltd., as Co-Documentation Agents; the other Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to PAA's Current Report on Form 8-K filed August 14, 2015).
10.3	—	First Amendment to Second Amended and Restated Credit Agreement dated as of August 14, 2015 among Plains AAP, L.P., as Borrower, Citibank, N.A. as Administrative Agent, and the other Lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 14, 2015).
12.1 †	—	Computation of Ratio of Earnings to Fixed Charges
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
101.SCH†	—	XBRL Taxonomy Extension Schema Document
101.CAL†	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE†	—	XBRL Taxonomy Extension Presentation Linkbase Document

†Filed herewith.

††Furnished herewith.