UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2014

OR

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

Commission File Number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes o 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 x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of October 31, 2014, there were 372,033,831 Common Units outstanding.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except unit data)

	September 30, 2014	December 31, 2013
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 34	$ 41
Trade accounts receivable and other receivables, net	3,522	3,638
Inventory	1,314	1,065
Other current assets	290	220
Total current assets	5,160	4,964
PROPERTY AND EQUIPMENT	13,816	12,473
Accumulated depreciation	(1,851)	(1,654)
Property and equipment, net	11,965	10,819
OTHER ASSETS		
Goodwill	2,481	2,503
Linefill and base gas	903	798
Long-term inventory	270	251
Investments in unconsolidated entities	582	485
Other, net	476	540
Total assets	$ 21,837	$ 20,360
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 4,169	$ 3,983
Short-term debt	976	1,113
Other current liabilities	423	315
Total current liabilities	5,568	5,411
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $16 and $15, respectively	7,609	6,710
Long-term debt under credit facilities and other	4	5
Other long-term liabilities and deferred credits	526	531
Total long-term liabilities	8,139	7,246
COMMITMENTS AND CONTINGENCIES (NOTE 11)		

PARTNERS CAPITAL				
Common unitholders (371,468,177 and 359,133,200 units outstanding, respectively)		7,740		7,349
General partner		331		295
Total partners capital excluding noncontrolling interests		8,071		7,644
Noncontrolling interests		59		59
Total partners capital		8,130		7,703
Total liabilities and partners capital	$	21,837	$	20,360

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 10,788	$ 10,386	$ 32,988	$ 30,542
Transportation segment revenues	198	179	574	517
Facilities segment revenues	141	138	443	558
Total revenues	11,127	10,703	34,005	31,617
COSTS AND EXPENSES				
Purchases and related costs	10,166	9,909	31,116	28,733
Field operating costs	382	326	1,078	1,010
General and administrative expenses	78	79	257	276
Depreciation and amortization	97	93	293	265
Total costs and expenses	10,723	10,407	32,744	30,284
OPERATING INCOME	404	296	1,261	1,333
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	29	19	73	42
Interest expense (net of capitalized interest of $12, $11, $33 and $30, respectively)	(85)	(72)	(246)	(224)
Other income/(expense), net	(4)	3	(2)	2
INCOME BEFORE TAX	344	246	1,086	1,153
Current income tax expense	(10)	(17)	(62)	(69)
Deferred income tax benefit/(expense)	(10)	8	(28)	(10)
NET INCOME	324	237	996	1,074
Net income attributable to noncontrolling interests	(1)	(6)	(2)	(22)
NET INCOME ATTRIBUTABLE TO PAA	$ 323	$ 231	$ 994	$ 1,052
NET INCOME ATTRIBUTABLE TO PAA:				
LIMITED PARTNERS	$ 195	$ 133	$ 630	$ 764
GENERAL PARTNER	$ 128	$ 98	$ 364	$ 288
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.52	$ 0.38	$ 1.71	$ 2.23
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.52	$ 0.38	$ 1.70	$ 2.22
BASIC WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	370	343	365	340
DILUTED WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	371	345	367	342

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(unaudited)		(unaudited)	
Net income	$ 324	$ 237	$ 996	$ 1,074
Other comprehensive income/(loss)	(167)	39	(211)	(99)
Comprehensive income	157	276	785	975
Comprehensive income attributable to noncontrolling interests	(1)	(7)	(2)	(27)
Comprehensive income attributable to PAA	$ 156	$ 269	$ 783	$ 948

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME / (LOSS)

(in millions)

	Derivative Instruments	Translation Adjustments	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)

	Derivative Instruments	Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2012	$ (120)	$ 200	$ 80
Reclassification adjustments	(124)		(124)
Deferred gain on cash flow hedges, net of tax	140		140
Currency translation adjustments		(115)	(115)
Total period activity	16	(115)	(99)
Balance at September 30, 2013	$ (104)	$ 85	$ (19)

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 996	$ 1,074
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	293	265
Equity-indexed compensation expense	90	96
Inventory valuation adjustments	37	7
Deferred income tax expense	28	10
Gain on sales of linefill and base gas	(8)	(5)
(Gain)/loss on foreign currency revaluation	10	(6)
Settlement of terminated interest rate hedging instruments	(7)	8
Equity earnings in unconsolidated entities, net of distributions	1	(7)
Other	10	
Changes in assets and liabilities, net of acquisitions	(172)	152
Net cash provided by operating activities	1,278	1,594
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(10)	(28)
Additions to property, equipment and other	(1,424)	(1,217)
Cash received for sales of linefill and base gas	24	25
Cash paid for purchases of linefill and base gas	(159)	(61)
Investment in unconsolidated entities	(98)	(124)
Proceeds from sales of assets	2	62
Other investing activities	1	3
Net cash used in investing activities	(1,664)	(1,340)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments under PAA senior secured hedged inventory facility (Note 6)		(659)
Net repayments under PAA senior unsecured revolving credit facility (Note 6)		(92)
Net repayments under PNG credit agreement		(32)
Net borrowings/(repayments) under PAA commercial paper program (Note 6)	(683)	319
Proceeds from the issuance of senior notes (Note 6)	1,447	699
Net proceeds from the issuance of common units (Note 8)	655	392
Contributions from general partner	14	8
Net proceeds from the issuance of PNG common units		40
Distributions paid to common unitholders (Note 8)	(688)	(585)
Distributions paid to general partner (Note 8)	(344)	(270)
Distributions paid to noncontrolling interests	(2)	(37)
Other financing activities	(19)	(25)
Net cash provided by/(used in) financing activities	380	(242)
Effect of translation adjustment on cash	(1)	(3)
Net increase/(decrease) in cash and cash equivalents	(7)	9
Cash and cash equivalents, beginning of period	41	24

Cash and cash equivalents, end of period	$	34	$	33
Cash paid for:				
Interest, net of amounts capitalized	$	237	$	230
Income taxes, net of amounts refunded	$	135	$	19

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS CAPITAL

(in millions)

	Common Units		General	Partners Capital Excluding Noncontrolling	Noncontrolling	Total Partners
	Units	Amount	Partner	Interests	Interests	Capital
			(unaudited)			
Balance at December 31, 2013	359.1	$ 7,349	$ 295	$ 7,644	$ 59	$ 7,703
Net income		630	364	994	2	996
Distributions		(688)	(344)	(1,032)	(2)	(1,034)
Issuance of common units	11.8	655	14	669		669
Issuance of common units under LTIP, net of units tendered by employees to satisfy tax withholding obligations	0.6	(18)	1	(17)		(17)
Equity-indexed compensation expense		25	5	30		30
Distribution equivalent right payments		(5)		(5)		(5)
Other comprehensive loss		(207)	(4)	(211)		(211)
Other		(1)		(1)		(1)
Balance at September 30, 2014	371.5	$ 7,740	$ 331	$ 8,071	$ 59	$ 8,130

	Common Units		General	Partners Capital Excluding Noncontrolling	Noncontrolling	Total Partners
	Units	Amount	Partner	Interests	Interests	Capital
			(unaudited)			
Balance at December 31, 2012	335.3	$ 6,388	$ 249	$ 6,637	$ 509	$ 7,146
Net income		764	288	1,052	22	1,074
Distributions		(585)	(270)	(855)	(37)	(892)
Issuance of common units	7.2	392	8	400		400
Issuance of common units under LTIP, net of units tendered by employees to satisfy tax withholding obligations	0.5	(11)		(11)		(11)
Equity-indexed compensation expense		24	4	28	3	31
Distribution equivalent right payments		(4)		(4)		(4)
Other comprehensive income/(loss)		(102)	(2)	(104)	5	(99)
Issuance of PNG common units		8		8	32	40

Other		(1)		(1)		(1)
Balance at September 30, 2013	343.0	$ 6,873	$ 277	$ 7,150	$ 534	$ 7,684

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Basis of Consolidation and Presentation

Organization

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

We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids (NGL), natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas (LPG), such as propane and butane. When used in this Form 10-Q, NGL refers to all NGL products including LPG. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 12 for further discussion of our operating segments.

Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P. (AAP), a Delaware limited partnership. In addition to its ownership of PAA GP LLC, AAP also owns all of our incentive distribution rights (IDRs). Plains All American GP LLC (GP LLC), a Delaware limited liability company, is AAP s general partner. Plains GP Holdings, L.P. (NYSE: PAGP) is the sole member of GP LLC, and at September 30, 2014, owned a 22.4% limited partner interest in AAP. GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and personnel are employed by our subsidiary, Plains Midstream Canada ULC (PMC). References to our general partner, as the context requires, include any or all of PAA GP LLC, AAP and GP LLC.

Definitions

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

AOCI	=	Accumulated other comprehensive income
Bcf	=	Billion cubic feet
Btu	=	British thermal unit

CAD	=	Canadian dollar
DERs	=	Distribution equivalent rights
EBITDA	=	Earnings before interest, taxes, depreciation and amortization
FASB	=	Financial Accounting Standards Board
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	IntercontinentalExchange
LIBOR	=	London Interbank Offered Rate
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
NYMEX	=	New York Mercantile Exchange
PLA	=	Pipeline loss allowance
PNG	=	PAA Natural Gas Storage, L.P.
SEC	=	Securities and Exchange Commission
USD	=	United States dollar
White Cliffs	=	White Cliffs Pipeline, LLC
WTI	=	West Texas Intermediate

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Basis of Consolidation and Presentation

The accompanying unaudited condensed consolidated interim financial statements and notes thereto should be read in conjunction with our 2013 Annual Report on Form 10-K. 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. Certain reclassifications have been made to information from previous years to conform to the current presentation. The condensed consolidated balance sheet data as of December 31, 2013 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, 2014 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

Other than as discussed below and in our 2013 Annual Report on Form 10-K, no new accounting pronouncements have become effective or have been issued during the nine months ended September 30, 2014 that are of significance or potential significance to us.

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 becomes effective for interim and annual periods beginning after December 15, 2016 and 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. We are currently evaluating which transition approach to apply and the effect 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. Early adoption is permitted but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issue. We are currently evaluating the provisions of this authoritative guidance and assessing its impact, but do not believe our adoption will have a material impact on our financial position, results of operations or cash flows.

In March 2013, the FASB issued guidance regarding the release of cumulative translation adjustments into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity. This guidance became effective for interim and annual periods beginning after December 15, 2013. We adopted this guidance on January 1, 2014. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

Note 3 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 storage. 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 have in place a rigorous credit review process. We closely monitor market conditions in order to make a determination with respect to the amount, if any, of 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, 2014 and December 31, 2013, we had received $181 million and $117 million, respectively, of advance cash payments from third parties to mitigate credit risk. Furthermore, as of September 30, 2014 and December 31, 2013, we had received $278 million and $426 million, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. In addition, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis.

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Further, we 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, 2014 and December 31, 2013, substantially all of our 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 and $5 million at September 30, 2014 and December 31, 2013, respectively. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Note 4 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, 2014				December 31, 2013			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)	Volumes	Unit of Measure	Carrying Value	Price/ Unit (1)
Inventory								
Crude oil	5,665	barrels	$ 476	$ 84.02	6,951	barrels	$ 540	$ 77.69
NGL	17,392	barrels	699	$ 40.19	8,061	barrels	352	$ 43.67
Natural gas	29,245	Mcf	119	$ 4.07	40,505	Mcf	150	$ 3.70
Other	N/A		20	N/A	N/A		23	N/A
Inventory subtotal			1,314				1,065	
Linefill and base gas								
Crude oil	11,390	barrels	715	$ 62.77	10,966	barrels	679	$ 61.92
NGL	1,214	barrels	54	$ 44.48	1,341	barrels	62	$ 46.23
Natural gas	28,612	Mcf	134	$ 4.68	16,615	Mcf	57	$ 3.43
Linefill and base gas subtotal			903				798	
Long-term inventory								
Crude oil	2,557	barrels	207	$ 80.95	2,498	barrels	202	$ 80.86
NGL	1,681	barrels	63	$ 37.48	1,161	barrels	49	$ 42.20
Long-term inventory subtotal			270				251	
Total			$ 2,487				$ 2,114	

(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. We did not record any such charges during the three months ended September 30, 2014. We recorded a charge of $37 million during the nine months ended September 30, 2014 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. During the three and nine months ended September 30, 2013, we recorded a charge of $7 million, primarily related to the writedown of our crude oil inventory due to declines in prices during the period. These adjustments are a component of Purchases and related costs on our accompanying condensed consolidated statements of operations. The recognition of the adjustment in 2013 was substantially offset by the recognition of gains on derivative instruments being utilized to hedge the future sales of our crude oil inventory. Substantially all of such gains were recorded to Supply and Logistics segment revenues on our accompanying condensed consolidated statements of operations. See Note 10 for discussion of our derivatives and risk management activities.

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Note 5 Goodwill

The table below reflects our goodwill by segment and changes during the period indicated (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Balance at December 31, 2013	$ 878	$ 1,162	$ 463	$ 2,503
Foreign currency translation adjustments	(14)	(6)	(3)	(23)
Other		1		1
Balance at September 30, 2014	$ 864	$ 1,157	$ 460	$ 2,481

We completed our annual goodwill impairment test as of June 30, 2014 and determined that there was no impairment of goodwill.

Note 6 Debt

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

	September 30, 2014	December 31, 2013
SHORT-TERM DEBT		
PAA commercial paper notes, bearing a weighted-average interest rate of 0.30% and 0.33%, respectively (1)	$ 423	$ 1,109
PAA senior notes:		
5.25% senior notes due June 2015	150	
3.95% senior notes due September 2015	400	
Other	3	4
Total short-term debt	976	1,113
LONG-TERM DEBT		
PAA senior notes:		
5.25% senior notes due June 2015		150
3.95% senior notes due September 2015		400
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	350
5.75% senior notes due January 2020	500	500
5.00% senior notes due February 2021	600	600
3.65% senior notes due June 2022	750	750
2.85% senior notes due January 2023	400	400
3.85% senior notes due October 2023	700	700
3.60% senior notes due November 2024	750	
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600

5.15% senior notes due June 2042		500		500
4.30% senior notes due January 2043		350		350
4.70% senior notes due June 2044		700		
Unamortized discounts		(16)		(15)
PAA senior notes, net of unamortized discounts		7,609		6,710
Other		4		5
Total long-term debt		7,613		6,715
Total debt (2)	$	8,589	$	7,828

(1) PAA commercial paper notes are backstopped by the PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory facility, which mature in August 2019 and August 2017, respectively; as such, any borrowings under the PAA commercial paper program effectively reduce the available capacity under these facilities. At September 30, 2014 and December 31, 2013, we classified $423 million and approximately $1.1 billion, respectively, of borrowings under our commercial paper program as short-term. These borrowings are primarily designated as working capital borrowings, must be repaid within one year and are primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

(2) Our fixed-rate senior notes (including current maturities) had a face value of approximately $8.2 billion and $6.7 billion at September 30, 2014 and December 31, 2013, respectively. We estimated the aggregate fair value of these notes as of September 30, 2014 and December 31, 2013 to be approximately $8.8 billion and $7.2 billion, respectively. Our fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near quarter end. We estimate that the carrying value of outstanding borrowings under our credit facilities and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities and commercial paper program are based upon observable market data and are classified within Level 2 of the fair value hierarchy. See Note 10 for additional discussion of the fair value hierarchy.

Credit Facilities

In August 2014, we extended the maturity dates of our senior secured hedged inventory facility and our senior unsecured revolving credit facility by one year through the exercise of the option included in the current credit agreements. Our senior secured hedged inventory facility and our senior unsecured revolving credit facility now mature in August 2017 and August 2019, respectively.

Borrowings and Repayments

Total borrowings under our credit agreements and the commercial paper program for the nine months ended September 30, 2014 and 2013 were approximately $55.6 billion and $12.7 billion, respectively. Total repayments under our credit agreements and the commercial paper program for the nine months ended September 30, 2014 and 2013 were approximately $56.3 billion and $13.2 billion, 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 and construction activities. At September 30, 2014 and December 31, 2013, we had outstanding letters of credit of $66 million and $41 million, respectively.

Senior Notes Issuances

On April 23, 2014, we completed the issuance of $700 million, 4.70% senior notes due 2044 at a public offering price of 99.734%. Interest payments are due on June 15 and December 15 of each year, commencing on December 15, 2014. In anticipation of the issuance of these senior notes, we entered into $250 million notional principal amount of U.S. treasury locks in March and April 2014 to hedge the treasury rate portion of the interest rate on a portion of the notes. We terminated these treasury locks in April 2014. See Note 10 for additional disclosure.

On September 9, 2014, we completed the issuance of $750 million, 3.60% senior notes due 2024 at a public offering price of 99.842%. Interest payments are due on May 1 and November 1 of each year, commencing on May 1, 2015.

Commercial Paper Program

Effective October 20, 2014, the maximum aggregate borrowing capacity under our commercial paper program was increased from $1.5 billion to $3.0 billion.

Note 7 Net Income Per Limited Partner Unit

Basic and diluted net income per limited partner unit is determined pursuant to the two-class method for Master Limited Partnerships as prescribed in FASB guidance. The two-class method is an earnings allocation formula that is used to determine earnings to our general partner, common unitholders and participating securities according to distributions pertaining to the current period s net income and participation rights in undistributed earnings. Under this method, all earnings are allocated to our general partner, common unitholders and participating securities based on their respective rights to receive distributions, regardless of whether those earnings would actually be distributed during a particular period from an economic or practical perspective.

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The Partnership calculates basic and diluted net income per limited partner unit by dividing net income attributable to PAA (after deducting the amount allocated to the general partner s interest, IDRs and participating securities) by the basic and diluted weighted-average number of limited partner units outstanding during the period. Participating securities include LTIP awards that have vested DERs, which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

Diluted net income per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by FASB. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2013 Annual Report on Form 10-K for a complete discussion of our LTIP awards including specific discussion regarding DERs.

The following table sets forth the computation of basic and diluted net income per limited partner unit for the three and nine months ended September 30, 2014 and 2013 (in millions, except per unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	**2013**	**2014**	**2013**
Basic Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 323	$ 231	$ 994	$ 1,052
Less: General partner s incentive distribution (1)	(124)	(95)	(351)	(272)
Less: General partner 2% ownership (1)	(4)	(3)	(13)	(16)
Net income available to limited partners	195	133	630	764
Less: Undistributed earnings allocated and distributions to participating securities (1)	(1)	(1)	(5)	(5)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 194	$ 132	$ 625	$ 759
Basic weighted average limited partner units outstanding	370	343	365	340
Basic net income per limited partner unit	$ 0.52	$ 0.38	$ 1.71	$ 2.23
Diluted Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 323	$ 231	$ 994	$ 1,052
Less: General partner s incentive distribution (1)	(124)	(95)	(351)	(272)
Less: General partner 2% ownership (1)	(4)	(3)	(13)	(16)
Net income available to limited partners	195	133	630	764
Less: Undistributed earnings allocated and distributions to participating securities (1)	(1)	(1)	(5)	(4)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 194	$ 132	$ 625	$ 760
Basic weighted average limited partner units outstanding	370	343	365	340
	1	2	2	2

Effect of dilutive securities: Weighted average LTIP units								
Diluted weighted average limited partner units outstanding		371		345		367		342
Diluted net income per limited partner unit	$	0.52	$	0.38	$	1.70	$	2.22

(1) We calculate net income available to limited partners based on the distributions pertaining to the current period s net income. After adjusting for the appropriate period s distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

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Pursuant to the terms of our partnership agreement, the general partner s incentive distribution is limited to a percentage of available cash, which, as defined in the partnership agreement, is net of reserves deemed appropriate. As such, IDRs are not allocated undistributed earnings or distributions in excess of earnings in the calculation of net income per limited partner unit. If, however, undistributed earnings were allocated to our IDRs beyond amounts distributed to them under the terms of the partnership agreement, basic and diluted net income per limited partner unit as reflected in the table above would be impacted as follows:

	Three Months Ended September 30 ,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Basic net income per limited partner unit impact	$	$	$	$ (0.23)
Diluted net income per limited partner unit impact	$	$	$	$ (0.23)

Note 8 Partners Capital and Distributions

Distributions

The following table details the distributions paid during or pertaining to the first nine months of 2014, net of reductions to the general partner s incentive distributions (in millions, except per unit data):

			Distributions Paid			
		Common	General Partner			Distributions per limited
Date Declared	Distribution Date	Units	Incentive	2%	Total	partner unit
October 8, 2014	November 14, 2014 (1)	$ 245	$ 124	$ 5	$ 374	$ 0.6600
July 8, 2014	August 14, 2014	$ 238	$ 117	$ 5	$ 360	$ 0.6450
April 7, 2014	May 15, 2014	$ 229	$ 110	$ 5	$ 344	$ 0.6300
January 9, 2014	February 14, 2014	$ 221	$ 102	$ 5	$ 328	$ 0.6150

(1) Payable to unitholders of record at the close of business on October 31, 2014 for the period July 1, 2014 through September 30, 2014.

Continuous Offering Program

In August 2014, we entered into an equity distribution agreement with several financial institutions pursuant to which we may offer and sell, through sales agents, common units representing limited partner interests having an aggregate offering price of up to $900 million. During the nine months ended September 30, 2014, we issued an aggregate of approximately 11.8 million common units under our continuous offering program, generating proceeds of $669 million, including our general partner s proportionate capital contribution of $14 million, net of $7 million of commissions to our sales agents.

Noncontrolling Interests in Subsidiaries

As of September 30, 2014, noncontrolling interests in subsidiaries consisted of a 25% interest in SLC Pipeline LLC. On December 31, 2013, we purchased the noncontrolling interests in PNG, and PNG became our wholly-owned subsidiary.

Note 9 Equity-Indexed Compensation Plans

We refer to the 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 15 to our Consolidated Financial Statements included in Part IV of our 2013 Annual Report on Form 10-K.

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PAA LTIP Awards

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

	Units (1)	Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2013	8.4	$ 36.97
Granted	1.1	$ 47.27
Vested (2)	(1.9)	$ 25.54
Cancelled or forfeited	(0.3)	$ 39.63
Outstanding at September 30, 2014	7.3	$ 41.28

(1) Amounts do not include AAP Management Units.

(2) During the nine months ended September 30, 2014, approximately 0.6 million PAA common units were issued, net of approximately 0.3 million units withheld for taxes, in connection with the settlement of vested awards. The remaining PAA awards (approximately 1.0 million units) that vested during the nine months ended September 30, 2014 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, 2013	3.5	48.6	47.0	$ 51
Granted	(0.4)	0.4		11
Earned	N/A	N/A	0.8	N/A
Balance at September 30, 2014	3.1	49.0	47.8	$ 62

(1) Of the $62 million grant date fair value, approximately $54 million had been recognized through September 30, 2014. Approximately $5 million of such amount was recognized as expense during the nine months ended September 30, 2014.

Other Consolidated Equity-Indexed Compensation Plan Information

The table below summarizes the expense recognized and the value of vested LTIPs (settled both in common units and cash) under our equity-indexed compensation plans and includes both liability-classified and equity-classified awards (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Equity-indexed compensation expense	$ 22	$ 17	$ 90	$ 96
LTIP unit-settled vestings	$ 1	$ 1	$ 52	$ 47
LTIP cash-settled vestings	$	$	$ 52	$ 61
DER cash payments	$ 2	$ 2	$ 6	$ 5

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Note 10 Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on hydrocarbon commodity (referred to herein as commodity) price changes. We use various derivative instruments to (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:

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, 2014, net derivative positions related to these activities included:

- An average of 248,700 barrels per day net long position (total of 7.7 million barrels) associated with our crude oil purchases, which was unwound ratably during October 2014 to match monthly average pricing.

- A net short time spread position averaging approximately 19,900 barrels per day (total of 11.5 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through June 2016. Our use of these derivatives does not expose us to outright price risk.

- An average of 15,200 barrels per day (total of 6.5 million barrels) of crude oil grade spread positions through December 2015. These derivatives allow us to lock in grade basis differentials. Our use of these derivatives does not expose us to outright price risk.

- A net short position of approximately 25.1 Bcf through April 2016 related to anticipated sales of natural gas inventory and base gas requirements.

- A net short position of approximately 12.1 million barrels through December 2015 related to the anticipated sales of our crude oil, NGL and refined products inventory.

Pipeline Loss Allowance Oil 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 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, 2014, our PLA hedges included a net short position for an average of approximately 1,400 barrels per day (total of 1.1 million barrels) through December 2016 and a long call position of approximately 0.6 million barrels through December 2016.

Natural Gas Processing/NGL Fractionation As part of our supply and logistics activities, we purchase natural gas for processing and NGL mix for fractionation, and we 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, 2014, we had a long natural gas position of approximately 33.3 Bcf through December 2016, a short propane position of approximately 5.4 million barrels through December 2016 and a short butane position of approximately 1.6 million barrels through December 2016.

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To the extent they qualify and we decide to make the election, all of our commodity derivatives where we elect hedge accounting are designated as cash flow hedges. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase normal sale scope exception. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the normal purchase normal sale scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of September 30, 2014, AOCI includes deferred losses of $108 million that relate to open and terminated interest rate derivatives that were designated for hedge accounting. 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 debt issuances through 2015. The following table summarizes the terms of our forward starting interest rate swaps as of September 30, 2014 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	10 forward starting swaps (30-year)	$ 250	6/15/2015	3.60%	Cash flow hedge

In anticipation of our April 2014 issuance of senior notes, we entered into an aggregate of five treasury lock agreements in March and April 2014 for a combined notional amount of $250 million at a locked in rate of 3.62%. The treasury locks were designated as cash flow hedges, thus, changes in fair value are deferred in AOCI. In connection with our April 2014 senior notes issuance, these treasury locks were terminated prior to maturity for an aggregate cash payment of $7 million. The effective portion of the treasury locks was deferred in AOCI and will be amortized to interest expense over the life of the senior notes.

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, 2014, 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.

The following table summarizes our open forward exchange contracts as of September 30, 2014 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2014	$ 284	$ 319	$1.00 - $1.12
	2015	178	200	$1.00 - $1.12
		$ 462	$ 519	$1.00 - $1.12
Forward exchange contracts that exchange USD for CAD:				
	2014	$ 284	$ 313	$1.00 - $1.10
	2015	178	195	$1.00 - $1.09
		$ 462	$ 508	$1.00 - $1.10

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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 reflected as cash flows from operating activities in our condensed consolidated statements of cash flows.

A summary of the impact of our derivative activities recognized in earnings for the three and nine months ended September 30, 2014 and 2013 is as follows (in millions):

	Three Months Ended September 30, 2014				**Three Months Ended September 30, 2013**			
	Derivatives in Hedging Relationships				**Derivatives in Hedging Relationships**			
Location of gain/(loss)	**Gain/(loss) reclassified from AOCI into income (1)**	**Other gain/(loss) recognized in income**	**Derivatives Not Designated as a Hedge**	**Total**	**Gain/(loss) reclassified from AOCI into income (1)**	**Other gain/(loss) recognized in income**	**Derivatives Not Designated as a Hedge**	**Total**
Commodity Derivatives								
Supply and Logistics segment revenues	$ (4)	$	$ (17)	$ (21)	$ 109	$	$ (91)	$ 18
Facilities segment revenues					(2)			(2)
Field operating costs			(2)	(2)			2	2
Interest Rate Derivatives								
Interest expense	(1)			(1)	(2)	3		1
Foreign Currency Derivatives								
Supply and Logistics segment revenues			(17)	(17)				
Other income/(expense), net					1			1
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (5)	$	$ (36)	$ (41)	$ 106	$ 3	$ (89)	$ 20

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	Nine Months Ended September 30, 2014				Nine Months Ended September 30, 2013			
	Derivatives in Hedging Relationships				Derivatives in Hedging Relationships			
Location of gain/(loss)	**Gain/(loss) reclassified from AOCI into income (1)**	**Other gain/(loss) recognized in income**	**Derivatives Not Designated as a Hedge**	**Total**	**Gain/(loss) reclassified from AOCI into income (1)**	**Other gain/(loss) recognized in income**	**Derivatives Not Designated as a Hedge**	**Total**
Commodity Derivatives								
Supply and Logistics segment revenues	$ (12)	$	$ (17)	$ (29)	$ 139	$	$ (34)	$ 105
Facilities segment revenues					(14)			(14)
Field operating costs			(3)	(3)			7	7
Interest Rate Derivatives								
Interest expense	(4)			(4)	(5)	3		(2)
Foreign Currency Derivatives								
Supply and Logistics segment revenues			(17)	(17)				
Other income/(expense), net					4			4
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (16)	$	$ (37)	$ (53)	$ 124	$ 3	$ (27)	$ 100

(1) During the three and nine months ended September 30, 2014, all of our hedged transactions were probable of occurring. During the three months ended September 30, 2013 we reclassified losses of $2 million from AOCI to Facilities segment revenues as a result of anticipated hedged transactions that were probable of not occurring. During the nine months ended September 30, 2013, we reclassified gains of $3 million and losses of $1 million from AOCI to Supply and Logistics segment revenues and Facilities segment revenues, respectively, as a result of anticipated hedged transactions that were probable of not occurring.

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The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of September 30, 2014 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	7			
	Other long-term assets		4			
Interest rate derivatives				Other current liabilities	$	(15)
Total derivatives designated as hedging instruments		$	11		$	(15)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	65	Other current assets	$	(43)
	Other long-term assets		5	Other current liabilities		(7)
	Other current liabilities		2	Other long-term liabilities		(2)
Foreign currency derivatives				Other current liabilities		(10)
Total derivatives not designated as hedging instruments		$	72		$	(62)
Total derivatives		$	83		$	(77)

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of December 31, 2013 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	36	Other current assets	$	(24)
	Other long-term assets		5			
Interest rate derivatives	Other long-term assets		26			
Total derivatives designated as hedging instruments		$	67		$	(24)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	60	Other current assets	$	(117)
	Other long-term assets		5	Other long-term assets		(6)
	Other current liabilities		1	Other current liabilities		(5)
				Other long-term liabilities		(1)
Foreign currency derivatives				Other current liabilities		(4)
Total derivatives not designated as hedging instruments		$	66		$	(133)

Total derivatives	$	133	$	(157)

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 our 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.

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Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of September 30, 2014, we had a net broker receivable of $35 million (consisting of initial margin of $74 million reduced by $39 million of variation margin that had been returned to us). As of December 31, 2013, we had a net broker receivable of $161 million (consisting of initial margin of $85 million increased by $76 million of variation margin that had been posted by us).

The following tables present information about derivatives and financial assets and liabilities that are subject to offsetting, including enforceable master netting arrangements at September 30, 2014 and December 31, 2013 (in millions):

	September 30, 2014		December 31, 2013	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 83	$ (77)	$ 133	$ (157)
Netting adjustment	(45)	45	(148)	148
Cash collateral paid/(received)	35		161	
Net position - asset/(liability)	$ 73	$ (32)	$ 146	$ (9)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 64	$	$ 116	$
Other long-term assets	9		30	
Other current liabilities		(30)		(8)
Other long-term liabilities		(2)		(1)
	$ 73	$ (32)	$ 146	$ (9)

As of September 30, 2014, there was a net loss of $118 million deferred in AOCI including tax effects. 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, 2014, we expect to reclassify a net gain of $1 million to earnings in the next twelve months. The remaining deferred loss of $119 million is expected to be reclassified to earnings through 2045. A portion of these amounts are based on market prices as of September 30, 2014; 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 three and nine months ended September 30, 2014 and 2013 are as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Commodity derivatives, net	$ 2	$ 66	$ (10)	$ 77
Interest rate derivatives, net	(8)	12	(47)	63
Total	$ (6)	$ 78	$ (57)	$ 140

At September 30, 2014 and December 31, 2013, 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 September 30, 2014 and December 31, 2013 (in millions):

	Fair Value as of September 30, 2014				Fair Value as of December 31, 2013			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 6	$ 22	$ 3	$ 31	$ 16	$ (59)	$ (3)	$ (46)
Interest rate derivatives		(15)		(15)		26		26
Foreign currency derivatives		(10)		(10)		(4)		(4)
Total net derivative asset/(liability)	$ 6	$ (3)	$ 3	$ 6	$ 16	$ (37)	$ (3)	$ (24)

(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.

Rollforward of Level 3 Net Asset/(Liability)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	**2013**	**2014**	**2013**
Beginning Balance	$ 1	$ 4	$ (3)	$ 4
Unrealized gains/(losses):				
Included in earnings (1)	1	(4)		(1)
Included in other comprehensive income				
Settlements		(1)	3	(3)
Derivatives entered into during the period	1		3	(1)
Transfers out of Level 3				
Ending Balance	$ 3	$ (1)	$ 3	$ (1)
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the periods	$ 2	$ (4)	$ 3	$ (1)

(1) We reported 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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Note 11 Commitments and Contingencies

Litigation

General. In the ordinary course of business, we are involved in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, 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 the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows. Although we believe that our operations are presently in material compliance with applicable requirements, as we acquire and incorporate additional assets it is possible that the EPA or other governmental entities may seek to impose fines, penalties or performance obligations on us (or on a portion of our operations) as a result of any past noncompliance whether such noncompliance initially developed before or after our acquisition.

Environmental

General. Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, 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 unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

At September 30, 2014, our estimated undiscounted reserve for environmental liabilities totaled $87 million, of which $13 million was classified as short-term and $74 million was classified as long-term. At December 31, 2013, our estimated undiscounted reserve for environmental liabilities totaled $93 million, of which $11 million was classified as short-term and $82 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, 2014 and December 31, 2013, we had recorded receivables totaling $9 million and $10 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 may not occur for three years or longer. Our estimates used in 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 financial condition, results of operations or cash flows.

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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 oil was contained within our pipeline right of way, but some of the released 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 approximately $6 million.

Kemp River Pipeline Release. 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. AER s final investigation 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 associated with these releases will be approximately $15 million. Through September 30, 2014, we spent approximately $8 million in connection with clean-up and remediation activities.

Note 12 Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) 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 (i) purchases and related costs, (ii) field operating costs and (iii) 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.

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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, 2014				
Revenues (1):				
External Customers	$ 198	$ 141	$ 10,788	$ 11,127
Intersegment (2)	226	140	5	371
Total revenues of reportable segments	$ 424	$ 281	$ 10,793	$ 11,498
Equity earnings in unconsolidated entities	$ 29	$	$	$ 29
Segment profit (3) (4)	$ 231	$ 147	$ 152	$ 530
Maintenance capital	$ 35	$ 19	$ 2	$ 56
Three Months Ended September 30, 2013				
Revenues:				
External Customers	$ 179	$ 138	$ 10,386	$ 10,703
Intersegment (2)	199	142		341
Total revenues of reportable segments	$ 378	$ 280	$ 10,386	$ 11,044
Equity earnings in unconsolidated entities	$ 19	$	$	$ 19
Segment profit (3) (4)	$ 198	$ 146	$ 64	$ 408
Maintenance capital	$ 29	$ 6	$ 7	$ 42

	Transportation	Facilities	Supply and Logistics	Total
Nine Months Ended September 30, 2014				
Revenues (1):				
External Customers	$ 574	$ 443	$ 32,988	$ 34,005
Intersegment (2)	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 (3) (4)	$ 658	$ 435	$ 534	$ 1,627
Maintenance capital	$ 111	$ 34	$ 6	$ 151
Nine Months Ended September 30, 2013				
Revenues:				
External Customers	$ 517	$ 558	$ 30,542	$ 31,617
Intersegment (2)	594	425	2	1,021
Total revenues of reportable segments	$ 1,111	$ 983	$ 30,544	$ 32,638
Equity earnings in unconsolidated entities	$ 42	$	$	$ 42
Segment profit (3) (4)	$ 522	$ 445	$ 673	$ 1,640
Maintenance capital	$ 84	$ 23	$ 17	$ 124

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(1) Effective January 1, 2014, our natural gas sales and costs, primarily attributable to the activities performed by our natural gas storage commercial optimization group, are reported in the Supply and Logistics segment. Such items were previously reported in the

Facilities segment.

(2) 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 2013 Annual Report on Form 10-K.

(3) Supply and Logistics segment profit includes interest expense (related to hedged inventory purchases) of $4 million and $8 million for the three months ended September 30, 2014 and 2013, respectively, and $11 million and $21 million for the nine months ended September 30, 2014 and 2013, respectively.

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(4) The following table reconciles segment profit to net income attributable to PAA (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Segment profit	$ 530	$ 408	$ 1,627	$ 1,640
Depreciation and amortization	(97)	(93)	(293)	(265)
Interest expense, net	(85)	(72)	(246)	(224)
Other income/(expense), net	(4)	3	(2)	2
Income before tax	344	246	1,086	1,153
Income tax expense	(20)	(9)	(90)	(79)
Net income	324	237	996	1,074
Net income attributable to noncontrolling interests	(1)	(6)	(2)	(22)
Net income attributable to PAA	$ 323	$ 231	$ 994	$ 1,052

Note 13 Related Party Transactions

See Note 14 to our Consolidated Financial Statements included in Part IV of our 2013 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Occidental Petroleum Corporation

As of September 30, 2014, a subsidiary of Occidental Petroleum Corporation (Oxy) owned approximately 25% of our general partner and had a representative on the board of directors of GP LLC. During the three and nine months ended September 30, 2014 and 2013, we recognized sales and transportation revenues and purchased petroleum products from companies affiliated with Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market. See detail below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues	$ 369	$ 441	$ 812	$ 1,135
Purchases and related costs	$ 233	$ 229	$ 701	$ 604

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

	September 30, 2014	December 31, 2013

Trade accounts receivable and other receivables	$ 274	$ 133
Accounts payable	$ 233	$ 181

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Note 14 Subsequent Events

As of November 5, 2014, we entered into a definitive purchase and sale agreement with Oxy that provides for our purchase of Oxy s 50% interest in BridgeTex Pipeline Company LLC (BridgeTex) for $1.075 billion. BridgeTex owns a 300,000 barrel-per-day crude oil pipeline (BridgeTex Pipeline) that extends from Colorado City in West Texas to Texas City. The remaining 50% interest in BridgeTex is owned by Magellan Midstream Partners, L.P. (MMP), which is also the operator of the BridgeTex Pipeline. Contemporaneous with the purchase by us of Oxy s 50% interest in BridgeTex, BridgeTex has agreed to sell the southern leg of the pipeline system which runs from Houston to Texas City (the Texas City Leg) to MMP, and MMP has agreed to enter into a long term capacity lease with BridgeTex pursuant to which BridgeTex shippers will have access to capacity on the Texas City Leg.

In addition to customary closing conditions and the contemporaneous consummation of the sale of the Texas City Leg and execution of the capacity lease, our acquisition of Oxy s 50% interest in BridgeTex is subject to the completion by PAGP, prior to December 31, 2014, of an underwritten secondary offering pursuant to which Oxy would sell a portion of its equity interest in PAGP. In order to facilitate such offering and the overall transaction, (i) the board of directors of PAGP s general partner has agreed to an early release of the 15-month lock-up arrangement that was originally imposed on certain PAGP equity owners, including Oxy, in connection with PAGP s initial public offering in October 2013, (ii) certain affiliates of Kayne Anderson Investment Management, Inc., The Energy & Minerals Group and PAA Management, L.P. have agreed to waive their participation rights in such offering and (iii) Oxy, certain affiliates of Kayne Anderson Investment Management, Inc., The Energy & Minerals Group and PAA Management, L.P. have agreed to refrain from selling any of their respective interests in PAGP for a period of up to 90 days following such offering. If an offering is not completed prior to December 31, 2014, both PAA and Oxy have the right to terminate the purchase and sale agreement.

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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 2013 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 Internal Growth Projects
- Results of Operations
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Forward-Looking Statements

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services for crude oil, NGL, natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics.

Overview of Operating Results, Capital Investments and Significant Activities

During the first nine months of 2014, we recognized net income attributable to PAA of $994 million as compared to net income attributable to PAA of $1.052 billion recognized during the first nine months of 2013. These results include total segment profit that was relatively flat between periods, but higher costs as discussed further below.

Our segment profit includes favorable results from our Transportation segment, primarily driven by the continued increase in North American crude oil production and our related, recently completed internal growth projects. These favorable results were offset by less favorable results from our NGL marketing activities in our Supply and Logistics segment, partially offset by a favorable period-over-period impact from the mark-to-market of derivative instruments. Our results were also impacted by decreased margins from our crude oil marketing activities; however, these unfavorable results were primarily attributable to the comparative first-quarter periods, as we experienced more favorable results in the second and third quarters of 2014. In addition, our Facilities and Supply and Logistics segments were negatively impacted by costs incurred in our natural gas storage activities to manage deliverability requirements in conjunction with the severe cold weather experienced during the first quarter of 2014.

Other significant items during the period were:

- Increased depreciation and amortization expense resulting from internal growth projects completed since September 30, 2013 and accelerated depreciation on certain pipeline assets;

- Increased interest expense resulting from higher average debt outstanding during the 2014 period;

- Increased income tax expense resulting from higher year over year earnings from our taxable Canadian operations; and

- A reduction in net income attributable to noncontrolling interests.

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Acquisitions and Internal Growth Projects

The following table summarizes our capital expenditures for acquisitions, internal growth projects and maintenance capital for the periods indicated (in millions):

	Nine Months Ended September 30, 2014		Nine Months Ended September 30, 2013	
Acquisition capital	$	10	$	19
Internal growth projects		1,552		1,253
Maintenance capital		151		124
Total	$	1,713	$	1,396

Internal Growth Projects

The following table summarizes our more notable projects in progress during 2014 and the forecasted expenditures for the year ending December 31, 2014 (in millions):

Projects	**2014**
Permian Basin Area Projects	$425
Cactus Pipeline	350
Rail Terminal Projects (1)	235
Ft. Sask Facility Projects / NGL Line	130
Eagle Ford JV Project	110
Western Oklahoma Extension	80
Mississippian Lime Pipeline	55
White Cliffs Expansion	40
Line 63 Reactivation	35
Natural Gas Storage Expansions	35
Diamond Pipeline	25
St. James Facility Expansions	25
Other Projects	505
	$2,050
Potential Adjustments for Timing / Scope Refinement (2)	-$100 + $100
Total Projected Expansion Capital Expenditures	$1,950 - $2,150

(1) Includes projects located in or near Bakersfield, CA; Carr, CO; Van Hook, ND; and Kerrobert, Canada.

(2) Potential variation to current capital costs estimates may result from changes to project design, final cost of materials and labor and 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: (i) Transportation, (ii) Facilities and (iii) 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 18 to our Consolidated Financial Statements included in Part IV of our 2013 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 (in millions, except per unit data):

	Three Months Ended September 30,		Favorable/ (Unfavorable) Variance		Nine Months Ended September 30,		Favorable/ (Unfavorable) Variance	
	2014	2013	$	%	2014	2013	$	%
Transportation segment profit	$ 231	$ 198	$ 33	17%	$ 658	$ 522	$ 136	26%
Facilities segment profit	147	146	1	1%	435	445	(10)	(2)%
Supply and Logistics segment profit	152	64	88	138%	534	673	(139)	(21)%
Total segment profit	530	408	122	30%	1,627	1,640	(13)	(1)%
Depreciation and amortization	(97)	(93)	(4)	(4)%	(293)	(265)	(28)	(11)%
Interest expense, net	(85)	(72)	(13)	(18)%	(246)	(224)	(22)	(10)%
Other income/(expense), net	(4)	3	(7)	(233)%	(2)	2	(4)	(200)%
Income tax expense	(20)	(9)	(11)	(122)%	(90)	(79)	(11)	(14)%
Net income	324	237	87	37%	996	1,074	(78)	(7)%
Net income attributable to noncontrolling interests	(1)	(6)	5	83%	(2)	(22)	20	91%
Net income attributable to PAA	$ 323	$ 231	$ 92	40%	$ 994	$ 1,052	$ (58)	(6)%
Net income attributable to PAA:								
Basic net income per limited partner unit	$ 0.52	$ 0.38	$ 0.14	37%	$ 1.71	$ 2.23	$ (0.52)	(23)%
Diluted net income per limited partner unit	$ 0.52	$ 0.38	$ 0.14	37%	$ 1.70	$ 2.22	$ (0.52)	(23)%
Basic weighted average limited partner units outstanding	370	343	27	8%	365	340	25	7%
Diluted weighted average limited partner units outstanding	371	345	26	8%	367	342	25	7%

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as non-GAAP financial measures in its evaluation of past performance and prospects for the future. The primary additional measures used by management are adjusted earnings before interest, taxes, depreciation and amortization (adjusted EBITDA) and implied distributable cash flow (DCF).

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market adjustment of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), (iii) items that are not indicative of our core operating results and business outlook and/or (iv) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items hereinafter as Selected Items Impacting Comparability. These additional financial measures are reconciled to the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our condensed consolidated financial statements and footnotes.

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The following table sets forth non-GAAP financial measures that are reconciled to the most directly comparable GAAP measures (in millions):

[redacted]								
Net income	$ 324	$ 237	$ 87	37%	$ 996	$ 1,074	$ (78)	(7)%
[redacted]								
Interest expense, net	85	72	13	18%	246	224	22	10%
[redacted]								
Depreciation and amortization	97	93	4	4%	293	265	28	11%
[redacted]								
[redacted]								
Gains/(losses) from derivative activities net of inventory valuation adjustments (1)	$ 27	$ (59)	$ 86	146%	$ 77	$ (9)	$ 86	956%
[redacted]								
Net gain/(loss) on foreign currency revaluation (3)	(16)	2	(18)	(900)%	(10)	5	(15)	(300)%
[redacted]								
[redacted]								
Selected Items Impacting Comparability of EBITDA	1	69	(68)	(99)%	(19)	55	(74)	(135)%
[redacted]								
[redacted]								
Interest expense, net	(85)	(72)	(13)	(18)%	(246)	(224)	(22)	(10)%
[redacted]								
Current income tax expense	(10)	(17)	7	41%	(62)	(69)	7	10%
[redacted]								
Distributions to noncontrolling interests (5)	(1)	(13)	12	92%	(3)	(38)	35	92%
[redacted]								
Less: Distributions paid (5)	(374)	(305)			(1,078)	(886)		
[redacted]								

(1) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining Adjusted EBITDA. We also exclude the impact of corresponding inventory valuation adjustments, as applicable. See Note 10 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and risk management activities.

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(2) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2013 Annual Report on Form 10-K for a comprehensive discussion regarding our equity-indexed compensation plans.

(3) During the three and nine months ended September 30, 2014 and 2013, there were fluctuations in the value of the Canadian dollar (CAD) to the U.S. dollar (USD), resulting in gains and losses that were not related to our core operating results for the period and were thus classified as selected items impacting comparability. See Note 10 to our condensed consolidated financial statements for further discussion regarding our currency exchange rate risk hedging activities.

(4) Maintenance capital expenditures are defined as 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.

(5) Includes distributions that pertain to the current period s net income and are paid in the subsequent period.

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

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 leases of pipeline capacity and other transportation fees.

The following table sets forth operating results from our Transportation segment for the periods indicated:

[redacted]								
Revenues								
[redacted]								
Trucking	52	49	3	6%	159	152	7	5%
[redacted]								
[redacted]								
Trucking costs	(38)	(35)	(3)	(9)%	(116)	(109)	(7)	(6)%
[redacted]								
Equity-indexed compensation expense - operations	(4)	(3)	(1)	(33)%	(14)	(15)	1	7%
[redacted]								
Equity-indexed compensation expense - general and administrative	(7)	(5)	(2)	(40)%	(26)	(31)	5	16%
[redacted]								
Segment profit	$ 231	$ 198	$ 33	17%	$ 658	$ 522	$ 136	26%
[redacted]								
Segment profit per barrel	$ 0.59	$ 0.58	$ 0.01	2%	$ 0.60	$ 0.52	$ 0.08	15%

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Average Daily Volumes (in thousands of barrels per day) (4)	Three Months Ended September 30, 2014	2013	Favorable/ (Unfavorable) Variance Volumes	%	Nine Months Ended September 30, 2014	2013	Favorable/ (Unfavorable) Variance Volumes	%
Tariff activities								
Crude Oil Pipelines								
All American	40	40		%	37	39	(2)	(5)%
Bakken Area Systems	164	136	28	21%	147	130	17	13%
Basin / Mesa	743	731	12	2%	734	712	22	3%
Capline	178	147	31	21%	142	153	(11)	(7)%
Eagle Ford Area Systems	247	119	128	108%	215	81	134	165%
Line 63 / Line 2000	126	113	13	12%	119	113	6	5%
Manito	44	47	(3)	(6)%	44	46	(2)	(4)%
Mid-Continent Area Systems	346	256	90	35%	340	277	63	23%
Permian Basin Area Systems	776	593	183	31%	765	540	225	42%
Rainbow	104	128	(24)	(19)%	111	125	(14)	(11)%
Rangeland	61	54	7	13%	65	59	6	10%
Salt Lake City Area Systems	140	131	9	7%	134	132	2	2%
South Saskatchewan	62	56	6	11%	61	50	11	22%
White Cliffs	33	22	11	50%	27	22	5	23%
Other	831	738	93	13%	747	737	10	1%
NGL Pipelines								
Co-Ed	57	56	1	2%	56	55	1	2%
Other	143	200	(57)	(29)%	127	190	(63)	(33)%
Refined Products Pipelines		54	(54)	(100)%		88	(88)	(100)%
Tariff activities total	4,095	3,621	474	13%	3,871	3,549	322	9%
Trucking	131	120	11	9%	129	113	16	14%
Transportation segment total	4,226	3,741	485	13%	4,000	3,662	338	9%

(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 internal growth 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.

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 leases generally reflects a negotiated amount.

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 noted in the table above, our total Transportation segment revenues, net of trucking costs, and volumes increased for both the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013. Our Transportation segment results for the comparative periods were impacted by the following:

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- North American Crude Oil Production and Related Expansion Projects The increase in North American crude oil production has had a favorable impact on volumes and revenues on our existing pipeline systems and has also provided opportunities for midstream infrastructure development in production growth areas. The resulting increases in volumes for the three and nine months ended September 30, 2014 over the comparable 2013 periods were most notably on our Permian Basin, Eagle Ford and Mid-Continent Area Systems. We estimate that increased production combined with our recently completed internal growth projects increased revenues by $20 million and $70 million for the three and nine months ended September 30, 2014, respectively, compared to the three and nine months ended September 30, 2013.

- 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 increased by $7 million and $37 million, respectively, for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013 driven primarily by higher volumes.

- Rate Changes Revenues on our pipelines are impacted by various rate changes that may occur during the period. These primarily include the indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate and Canadian pipelines or other negotiated rate changes. We estimate that the net impact of rate changes on our pipelines increased revenues by $17 million and $30 million for the three and nine months ended September 30, 2014, respectively, compared to the three and nine months ended September 30, 2013.

- Sale of Refined Products Pipelines We sold certain refined products pipeline systems and related assets in July 2013 and November 2013. As we did not own these assets during the three and nine months ended September 30, 2014, our revenues were lower by $7 million and $27 million, respectively, and volumes were lower by 54,000 and 88,000 barrels per day, respectively, as compared to the three and nine months ended September 30, 2013.

- Foreign Exchange Impact 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. The average CAD to USD exchange rates for the three months ended September 30, 2014 and 2013 were $1.09 CAD: $1.00 USD and $1.04 CAD: $1.00 USD, respectively. The average CAD to USD exchange rates for the nine months ended September 30, 2014 and 2013 were $1.09 CAD: $1.00 USD and $1.02 CAD: $1.00 USD, respectively. Therefore, we estimate that revenues from our Canadian pipeline systems and trucking operations were unfavorably impacted by $5 million and $20 million for the three and nine months ended September 30, 2014, respectively, compared to the three and nine months ended September 30, 2013 due to the depreciation of the Canadian dollar relative to the U.S. dollar.

Additional noteworthy volume and revenue variances on our pipelines for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013 were (i) increased volumes and revenues on our Rangeland, South Saskatchewan and Co-Ed pipelines, as these pipelines were shut down during a portion of the second and third quarters of 2013 due to high river flow rates and flooding in the surrounding area, (ii) incremental volumes and revenues from our Pascagoula, Wascana and Bakken North pipelines, which were placed into service during the second quarter of 2014, (iii) incremental revenues from increased pumpover volumes at our Basin pipeline terminal, (iv) decreased volumes and revenues on our Rainbow pipeline due to (a) lower producer volumes and (b) operational issues during September 2014, (v) higher revenues resulting from a reclassification of certain of our Canadian storage facilities to our Transportation segment during the second quarter of 2014, (vi) increased volumes and revenues on our Line 2000 pipeline for the three-month comparable period due to increased refiner demand for heavy volumes, (vii) increased volumes and revenues on our Capline pipeline for the three-month comparative period due to the timing of a refinery turnaround, which occurred in the third quarter of 2013 and (viii) decreased volumes and revenues on certain of our NGL pipelines due to (a) the discontinuation in the fourth quarter of 2013 of an agreement to transport volumes on a pipeline and

(b) the impact of netting joint venture related volumes to our share on a pipeline during 2014, which did not affect revenues.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expenses) increased during the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013 due to (i) a change in classification of certain costs from General and Administrative expenses, (ii) increased asset integrity spending, (iii) higher utility costs associated with increased throughput volumes and (iv) operational issues related to crude oil contamination. The increase in field operating costs was not as pronounced for the comparative nine-month periods due to higher environmental remediation costs in 2013.

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General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) decreased during the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013 primarily due to a change in classification of certain costs to Field Operating Costs.

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 increase in maintenance capital for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013 is primarily due to increased investments on integrity-related projects.

Equity-Indexed Compensation Expense. On a consolidated basis across all segments, equity-indexed compensation expense increased for the three months ended September 30, 2014 compared to the same period in 2013, primarily due to a smaller impact of the decrease in unit price during the period compared to the impact of the decrease in unit price for the same period in 2013. Consolidated equity-indexed compensation expense decreased for the nine months ended September 30, 2014 compared to the same period in 2013, primarily due to a less significant impact of the increase in unit price during the nine months ended September 30, 2014 compared to the same period in 2013.

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 15 to our Consolidated Financial Statements included in Part IV of our 2013 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, 2014 compared to the three and nine months ended September 30, 2013 was largely due to increased throughput on the Eagle Ford joint venture pipeline as a result of increased production, as discussed above, and increased throughput on the White Cliffs pipeline due to an expansion of the pipeline that was placed into service in July 2014.

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.

The following table sets forth operating results from our Facilities segment for the periods indicated:

	Three Months Ended	Favorable/ (Unfavorable)	Nine Months Ended	Favorable/ (Unfavorable)

Operating Results (1) **(in millions, except per barrel data)**	**September 30, 2014**	**September 30, 2013**	**Variance $**	**Variance %**	**September 30, 2014**	**September 30, 2013**	**Variance $**	**Variance %**
Revenues	$ 281	$ 257	$ 24	9%	$ 858	$ 787	$ 71	9%
Natural gas sales (2)		23	(23)	(100)%		196	(196)	(100)%
Storage related costs (natural gas related)	(9)	(4)	(5)	(125)%	(47)	(12)	(35)	(292)%
Natural gas sales costs (2)		(19)	19	100%		(184)	184	100%
Field operating costs (3)	(104)	(92)	(12)	(13)%	(307)	(272)	(35)	(13)%
Equity-indexed compensation expense - operations	(1)		(1)	N/A	(4)	(2)	(2)	(100)%
Segment general and administrative expenses (3) (4)	(16)	(15)	(1)	(7)%	(46)	(48)	2	4%
Equity-indexed compensation expense - general and administrative	(4)	(4)		%	(19)	(20)	1	