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.

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 (unaudited)	Total
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 (unaudited)	Total
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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS CAPITAL

(in millions)

	Common Units Units	Common Units Amount	General Partner	Partners Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners 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 Units	Common Units Amount	General Partner	Partners Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners 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.

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(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):

Date Declared	Distribution Date	Common Units	Distributions Paid General Partner Incentive	Distributions Paid General Partner 2%	Total	Distributions per limited 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)