PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 08, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 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 July 31, 2014, there were 368,940,903 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)

	June 30, 2014	December 31, 2013
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 27	$ 41
Trade accounts receivable and other receivables, net	3,730	3,638
Inventory	1,096	1,065
Other current assets	315	220
Total current assets	5,168	4,964
PROPERTY AND EQUIPMENT	13,410	12,473
Accumulated depreciation	(1,797)	(1,654)
Property and equipment, net	11,613	10,819
OTHER ASSETS		
Goodwill	2,502	2,503
Linefill and base gas	895	798
Long-term inventory	287	251
Investments in unconsolidated entities	545	485
Other, net	485	540
Total assets	$ 21,495	$ 20,360
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 4,301	$ 3,983
Short-term debt	763	1,113
Other current liabilities	359	315
Total current liabilities	5,423	5,411
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $16 and $15, respectively	7,409	6,710
Long-term debt under credit facilities and other	5	5
Other long-term liabilities and deferred credits	546	531
Total long-term liabilities	7,960	7,246
COMMITMENTS AND CONTINGENCIES (NOTE 11)		

PARTNERS CAPITAL				
Common unitholders (367,822,748 and 359,133,200 units outstanding, respectively)		7,731		7,349
General partner		322		295
Total partners capital excluding noncontrolling interests		8,053		7,644
Noncontrolling interests		59		59
Total partners capital		8,112		7,703
Total liabilities and partners capital	$	21,495	$	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 June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 10,856	$ 9,933	$ 22,201	$ 20,157
Transportation segment revenues	195	165	376	338
Facilities segment revenues	144	197	301	420
Total revenues	11,195	10,295	22,878	20,915
COSTS AND EXPENSES				
Purchases and related costs	10,280	9,387	20,950	18,825
Field operating costs	360	343	696	684
General and administrative expenses	90	91	179	196
Depreciation and amortization	100	91	196	173
Total costs and expenses	10,830	9,912	22,021	19,878
OPERATING INCOME	365	383	857	1,037
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	23	11	44	23
Interest expense (net of capitalized interest of $10, $10, $22 and $19, respectively)	(82)	(75)	(161)	(152)
Other income/(expense), net	4	(1)	2	(1)
INCOME BEFORE TAX	310	318	742	907
Current income tax expense	(16)	(8)	(52)	(53)
Deferred income tax expense	(6)	(10)	(18)	(17)
NET INCOME	288	300	672	837
Net income attributable to noncontrolling interests	(1)	(8)	(1)	(16)
NET INCOME ATTRIBUTABLE TO PAA	$ 287	$ 292	$ 671	$ 821
NET INCOME ATTRIBUTABLE TO PAA:				
LIMITED PARTNERS	$ 166	$ 197	$ 435	$ 631
GENERAL PARTNER	$ 121	$ 95	$ 236	$ 190
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.45	$ 0.58	$ 1.19	$ 1.85
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.45	$ 0.57	$ 1.18	$ 1.84
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	365	340	363	338
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	367	342	365	341

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(unaudited)		(unaudited)	
Net income	$ 288	$ 300	$ 672	$ 837
Other comprehensive income/(loss)	91	(92)	(45)	(138)
Comprehensive income	379	208	627	699
Comprehensive income attributable to noncontrolling interests	(1)	(15)	(1)	(20)
Comprehensive income attributable to PAA	$ 378	$ 193	$ 626	$ 679

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	10		10
Deferred loss on cash flow hedges, net of tax	(51)		(51)
Currency translation adjustments		(4)	(4)
Total period activity	(41)	(4)	(45)
Balance at June 30, 2014	$ (118)	$ (24)	$ (142)

	Derivative Instruments	Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2012	$ (120)	$ 200	$ 80
Reclassification adjustments	(16)		(16)
Deferred gain on cash flow hedges, net of tax	62		62
Currency translation adjustments		(184)	(184)

Total period activity		46		(184)		(138)
Balance at June 30, 2013	$	(74)	$	16	$	(58)

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)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 672	$ 837
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	196	173
Equity-indexed compensation expense	68	78
Inventory valuation adjustments	37	
Deferred income tax expense	18	17
Gain on sales of linefill and base gas	(8)	(3)
Gain on foreign currency revaluation	(5)	(5)
Settlement of terminated interest rate hedging instruments	(7)	
Equity earnings in unconsolidated entities, net of distributions	7	(1)
Other	5	
Changes in assets and liabilities, net of acquisitions	(20)	241
Net cash provided by operating activities	963	1,337
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(2)	(31)
Additions to property, equipment and other	(918)	(785)
Cash received for sales of linefill and base gas	23	14
Cash paid for purchases of linefill and base gas	(140)	(24)
Investment in unconsolidated entities	(67)	(112)
Proceeds from sales of assets	3	3
Other investing activities		3
Net cash used in investing activities	(1,101)	(932)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments under PAA senior secured hedged inventory facility (Note 6)		(85)
Net repayments under PAA senior unsecured revolving credit facility (Note 6)		(65)
Net repayments under PNG credit agreement		(36)
Net repayments under PAA commercial paper program (Note 6)	(344)	
Proceeds from the issuance of senior notes (Note 6)	698	
Net proceeds from the issuance of common units (Note 8)	453	331
Net proceeds from the issuance of PNG common units		30
Distributions paid to common unitholders (Note 8)	(450)	(384)
Distributions paid to general partner (Note 8)	(222)	(175)
Distributions paid to noncontrolling interests	(1)	(24)
Other financing activities	(10)	(2)
Net cash provided by/(used in) financing activities	124	(410)
Effect of translation adjustment on cash		(3)
Net decrease in cash and cash equivalents	(14)	(8)
Cash and cash equivalents, beginning of period	41	24
Cash and cash equivalents, end of period	$ 27	$ 16

Cash paid for:				
Interest, net of amounts capitalized	$	161	$	146
Income taxes, net of amounts refunded	$	104	$	18

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	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		435	236	671	1	672
Distributions		(450)	(222)	(672)	(1)	(673)
Issuance of common units	8.1	444	9	453		453
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		19	4	23		23
Distribution equivalent right payments		(3)		(3)		(3)
Other comprehensive loss		(44)	(1)	(45)		(45)
Other		(1)		(1)		(1)
Balance at June 30, 2014	367.8	$ 7,731	$ 322	$ 8,053	$ 59	$ 8,112

	Common Units		General	Partners Capital Excluding Noncontrolling	Noncontrolling	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		631	190	821	16	837
Distributions		(384)	(175)	(559)	(24)	(583)
Issuance of common units	5.9	324	7	331		331
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		16	2	18	2	20
Distribution equivalent right payments		(3)		(3)		(3)
Other comprehensive income/(loss)		(139)	(3)	(142)	4	(138)
Issuance of PNG common units		6		6	24	30
Balance at June 30, 2013	341.7	$ 6,828	$ 270	$ 7,098	$ 531	$ 7,629

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. Plains All American GP LLC (GP LLC), a Delaware limited liability company, is AAP s general partner. 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
NGL	=	Natural gas liquids including ethane, natural gasoline products, propane and butane
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 six months ended June 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 six months ended June 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 June 30, 2014 and December 31, 2013, we had received approximately $157 million and $117 million, respectively, of advance cash payments from third parties to mitigate credit risk. Furthermore, as of June 30, 2014 and December 31, 2013, we had received approximately $384 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. 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.

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We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At June 30, 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 approximately $5 million at both June 30, 2014 and December 31, 2013. 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):

	June 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	6,233	barrels	$ 579	$ 92.89	6,951	barrels	$ 540	$ 77.69
NGL	10,591	barrels	444	$ 41.92	8,061	barrels	352	$ 43.67
Natural gas	10,824	Mcf	50	$ 4.62	40,505	Mcf	150	$ 3.70
Other	N/A		23	N/A	N/A		23	N/A
Inventory subtotal			1,096				1,065	
Linefill and base gas								
Crude oil	11,211	barrels	713	$ 63.60	10,966	barrels	679	$ 61.92
NGL	1,214	barrels	56	$ 46.13	1,341	barrels	62	$ 46.23
Natural gas	26,612	Mcf	126	$ 4.73	16,615	Mcf	57	$ 3.43
Linefill and base gas subtotal			895				798	
Long-term inventory								
Crude oil	2,712	barrels	220	$ 81.12	2,498	barrels	202	$ 80.86
NGL	1,681	barrels	67	$ 39.86	1,161	barrels	49	$ 42.20
Long-term inventory subtotal			287				251	
Total			$ 2,278				$ 2,114	

(1) Price per unit of measure represents 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 recorded a charge of approximately $37 million during the six months ended June 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. This adjustment is a component of Purchases and related costs in our accompanying condensed consolidated statements of operations.

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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	(1)			(1)
Balance at June 30, 2014	$ 877	$ 1,162	$ 463	$ 2,502

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):

	June 30, 2014	December 31, 2013
SHORT-TERM DEBT		
PAA commercial paper notes, bearing a weighted-average interest rate of 0.29% and 0.33%, respectively (1)	$ 760	$ 1,109
Other	3	4
Total short-term debt	763	1,113
LONG-TERM DEBT		
Senior notes, net of unamortized discounts of $16 and $15, respectively (2)	7,409	6,710
Other	5	5
Total long-term debt	7,414	6,715
Total debt (3)	$ 8,177	$ 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 2018 and August 2016, respectively; as such, any borrowings under the PAA commercial paper program reduce the available capacity under these facilities. At June 30, 2014 and December 31, 2013, we classified $760 million and $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) As of June 30, 2014, we have classified our $150 million, 5.25% senior notes due June 2015 as long-term based on our ability and intent to refinance them on a long-term basis.

(3) Our fixed-rate senior notes had a face value of approximately $7.4 billion and $6.7 billion at June 30, 2014 and December 31, 2013, respectively. We estimated the aggregate fair value of these notes as of June 30, 2014 and December 31, 2013 to be approximately $8.2 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 agreements and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for both our senior notes and credit facilities 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.

Borrowings and Repayments

Total borrowings under our credit agreements and the commercial paper program for the six months ended June 30, 2014 and 2013 were approximately $34.6 billion and $7.6 billion, respectively. Total repayments under our credit agreements and the commercial paper program for the six months ended June 30, 2014 and 2013 were approximately $34.9 billion and $7.8 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.

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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 June 30, 2014 and December 31, 2013, we had outstanding letters of credit of approximately $38 million and $41 million, respectively.

Senior Notes Issuance

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.

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 the 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.

The Partnership calculates basic and diluted net income per limited partner unit by dividing net income attributable to Plains, after deducting the amount allocated to the general partner s interest, incentive distribution rights (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 the 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.

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

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Basic Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 287	$ 292	$ 671	$ 821
Less: General partner s incentive distribution (1)	(117)	(91)	(227)	(177)
Less: General partner 2% ownership (1)	(4)	(4)	(9)	(13)
Net income available to limited partners	166	197	435	631
Less: Undistributed earnings allocated and distributions to participating securities (1)	(1)	(1)	(3)	(5)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 165	$ 196	$ 432	$ 626
Basic weighted average number of limited partner units outstanding	365	340	363	338
Basic net income per limited partner unit	$ 0.45	$ 0.58	$ 1.19	$ 1.85
Diluted Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 287	$ 292	$ 671	$ 821
Less: General partner s incentive distribution (1)	(117)	(91)	(227)	(177)
Less: General partner 2% ownership (1)	(4)	(4)	(9)	(13)
Net income available to limited partners	166	197	435	631
Less: Undistributed earnings allocated and distributions to participating securities (1)	(1)	(1)	(3)	(3)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 165	$ 196	$ 432	$ 628
Basic weighted average number of limited partner units outstanding	365	340	363	338
Effect of dilutive securities: Weighted average LTIP units	2	2	2	3
Diluted weighted average number of limited partner units outstanding	367	342	365	341
Diluted net income per limited partner unit	$ 0.45	$ 0.57	$ 1.18	$ 1.84

(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.

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 earnings per limited partner unit as reflected in the table above would be impacted as follows:

	Three Months Ended June 30 ,		Six Months Ended June 30,	
	2014	2013	2014	2013
Basic net income per limited partner unit impact	$	$	$	$ (0.33)
Diluted net income per limited partner unit impact	$	$	$	$ (0.33)

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Note 8 Partners Capital and Distributions

Distributions

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

		Distributions Paid				
		Common	General Partner			Distributions per limited
Date Declared	Distribution Date	Units	Incentive	2%	Total	partner unit
July 8, 2014	August 14, 2014 (1)	$ 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 August 1, 2014 for the period April 1, 2014 through June 30, 2014.

Continuous Offering Program

During the six months ended June 30, 2014, we issued an aggregate of approximately 8.1 million common units under our continuous offering program, generating proceeds of approximately $453 million, including our general partner s proportionate capital contribution, net of approximately $4 million of commissions to our sales agents.

Noncontrolling Interests in Subsidiaries

As of June 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.

PAA LTIP Awards. Our equity-indexed compensation activity for LTIP awards denominated in PAA units 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	0.9	$ 46.61
Vested (2)	(1.8)	$ 25.39
Cancelled or forfeited	(0.3)	$ 38.88
Outstanding at June 30, 2014	7.2	$ 41.05

(1) Amounts do not include AAP Management Units.

(2) Approximately 0.6 million PAA common units were issued, net of tax withholding of 0.3 million units, during the six months ended June 30, 2014 in connection with the settlement of vested awards. The remaining PAA awards that vested during the six months ended June 30, 2014 of approximately 0.9 million units were settled in cash.

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AAP Management Units. The following table contains a summary of AAP Management Units (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 June 30, 2014	3.1	49.0	47.8	$	62

(1) Of the grant date fair value, approximately $4 million was recognized as expense during the six months ended June 30, 2014. Of the $62 million grant date fair value, approximately $52 million had been recognized through June 30, 2014.

Other Consolidated Equity-Indexed Compensation Information. The table below summarizes the expense recognized and the value of vesting (settled both in units and cash) related to our equity-indexed compensation plans and includes both liability-classified and equity-classified awards (in millions):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
Equity-indexed compensation expense	$	34	$	27	$	68	$	78
LTIP unit-settled vestings	$	44	$	46	$	51	$	46
LTIP cash-settled vestings	$	51	$	60	$	52	$	60
DER cash payments	$	2	$	2	$	4	$	4

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 June 30, 2014, net derivative positions related to these activities included:

- An average of 210,100 barrels per day net long position (total of 6.5 million barrels) associated with our crude oil purchases, which was unwound ratably during July 2014 to match monthly average pricing.

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- A net short spread position averaging approximately 21,300 barrels per day (total of 14.3 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through June 2016. These derivatives are time spreads consisting of offsetting purchases and sales between two different months. Our use of these derivatives does not expose us to outright price risk.

- An average of 2,800 barrels per day (total of 0.8 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are priced as a percentage of WTI through March 2015.

- An average of 19,300 barrels per day (total of 1.8 million barrels) of WTI/Brent crude oil grade spread positions through September 2014. These derivatives allow us to lock in grade basis differentials where we are hedging anticipated purchases of crude oil based on a WTI index and hedging anticipated sales of crude oil based on a Brent index. Our use of these derivatives does not expose us to outright price risk.

- A long position of approximately 4.1 Bcf through April 2016 related to anticipated base gas requirements.

- A short position of approximately 10.7 Bcf through February 2015 related to anticipated sales of natural gas inventory.

- A net short position of approximately 7.6 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 June 30, 2014, our PLA hedges included a net short position for an average of approximately 1,600 barrels per day (total of 1.5 million barrels) through December 2016 and a long call option position of approximately 0.7 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 June 30, 2014, we had a long natural gas position of approximately 31.3 Bcf through December 2016, a short propane position of approximately 5.2 million barrels through December 2016, a short butane position of approximately 1.5 million barrels through December 2016 and a short WTI position of approximately 0.6 million barrels through December 2016. In addition, we had a long power position of 0.6 million megawatt hours which hedges a portion of our power supply requirements at our natural gas processing and fractionation plants through December 2016.

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 June 30, 2014, AOCI includes deferred losses of approximately $101 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 June 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

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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 3.64%. 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 approximately $7 million. The effective portion of the treasury locks was deferred in AOCI and 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 risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts and forwards.

As of June 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 June 30, 2014 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2014	$ 273	$ 292	$1.00 - $1.07
	2015	77	82	$1.00 - $1.07
		$ 350	$ 374	$1.00 - $1.07
Forward exchange contracts that exchange USD for CAD:				
	2014	$ 273	$ 297	$1.00 - $1.09
	2015	77	84	$1.00 - $1.09
		$ 350	$ 381	$1.00 - $1.09
Net position by currency:				
	2014	$	$ (5)	
	2015		(2)	
		$	$ (7)	

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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 six months ended June 30, 2014 and 2013 is as follows (in millions):

	Three Months Ended June 30, 2014				Three Months Ended June 30, 2013			
	Derivatives in Hedging Relationships				Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(loss) reclassified from AOCI into income	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	$	$	$ 12	$ 21	$	$ 21	$ 42
Facilities segment revenues					(9)			(9)
Field operating costs							4	4
Interest Rate Derivatives								
Interest expense	(1)			(1)	(2)			(2)
Foreign Currency Derivatives								
Supply and Logistics segment revenues			9	9				
Other income/(expense), net					1			1
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 11	$	$ 9	$ 20	$ 11	$	$ 25	$ 36

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Location of gain/(loss)	Six Months Ended June 30, 2014 — Derivatives in Hedging Relationships: Gain/(loss) reclassified from AOCI into income	Six Months Ended June 30, 2014 — Derivatives in Hedging Relationships: Other gain/(loss) recognized in income	Six Months Ended June 30, 2014 — Derivatives Not Designated as a Hedge	Six Months Ended June 30, 2014 — Total	Six Months Ended June 30, 2013 — Derivatives in Hedging Relationships: Gain/(loss) reclassified from AOCI into income (1)	Six Months Ended June 30, 2013 — Derivatives in Hedging Relationships: Other gain/(loss) recognized in income	Six Months Ended June 30, 2013 — Derivatives Not Designated as a Hedge	Six Months Ended June 30, 2013 — Total
Commodity Derivatives								
Supply and Logistics segment revenues	$ (8)	$	$	$ (8)	$ 29	$	$ 59	$ 88
Facilities segment revenues					(12)			(12)
Field operating costs			(1)	(1)			5	5
Interest Rate Derivatives								
Interest expense	(2)			(2)	(3)			(3)
Foreign Currency Derivatives								
Other income/(expense), net					2			2
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (10)	$	$ (1)	$ (11)	$ 16	$	$ 64	$ 80

(1) During the three months ended June 30, 2013 we reclassified gains of approximately $1 million and $1 million from AOCI to Supply and Logistics segment revenues and Facilities segment revenues, respectively, as a result of anticipated hedged transactions that are probable of not occurring. During the six months ended June 30, 2013, we reclassified gains of approximately $3 million and $1 million from AOCI to Supply and Logistics segment revenues and Facilities segment revenues, respectively, as a result of anticipated hedged transactions that are probable of not occurring. During the three and six months ended June 30, 2014, all of our hedged transactions were probable of 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 June 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 current assets	$ (4)
	Other long-term assets	1		
Interest rate derivatives	Other current assets	1	Other current liabilities	(8)
Total derivatives designated as hedging instruments		$ 9		$ (12)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 76	Other current assets	$ (56)
	Other long-term assets	2	Other long-term assets	(1)
	Other long-term liabilities	1	Other current liabilities	(1)
			Other long-term liabilities	(5)
Foreign currency derivatives	Other current assets	6		
Total derivatives not designated as hedging instruments		$ 85		$ (63)
Total derivatives		$ 94		$ (75)

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 June 30, 2014, we had a net broker receivable of approximately $66 million (consisting of initial margin of $54 million increased by $12 million of variation margin that had been posted by us). As of December 31, 2013, we had a net broker receivable of approximately $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 June 30, 2014 and December 31, 2013 (in millions):

	June 30, 2014		December 31, 2013	
	Derivative Asset Positions	**Derivative Liability Positions**	**Derivative Asset Positions**	**Derivative Liability Positions**
Netting Adjustments:				
Gross position - asset/(liability)	$ 94	$ (75)	$ 133	$ (157)
Netting adjustment	(62)	62	(148)	148
Cash collateral paid/(received)	66		161	
Net position - asset/(liability)	$ 98	$ (13)	$ 146	$ (9)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 96	$	$ 116	$
Other long-term assets	2		30	
Other current liabilities		(9)		(8)
Other long-term liabilities		(4)		(1)
	$ 98	$ (13)	$ 146	$ (9)

As of June 30, 2014, there was a net loss of approximately $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 June 30, 2014, we expect to reclassify a net loss of approximately $4 million to earnings in the next twelve months. The remaining deferred loss of approximately $114 million is expected to be reclassified to earnings through 2045. A portion of these amounts are based on market prices as of June 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 six months ended June 30, 2014 and 2013 are as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Commodity derivatives, net	$	$ 3	$ (12)	$ 11
Interest rate derivatives, net	(19)	32	(39)	51
Total	$ (19)	$ 35	$ (51)	$ 62

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

	Fair Value as of June 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	$ 28	$ (9)	$ 1	$ 20	$ 16	$ (59)	$ (3)	$ (46)
Interest rate derivatives		(7)		(7)		26		26
Foreign currency derivatives		6		6		(4)		(4)
Total net derivative asset/(liability)	$ 28	$ (10)	$ 1	$ 19	$ 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.

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Rollforward of Level 3 Net Asset

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

(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.

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.

Pemex Exploración y Producción v. Big Star Gathering Ltd L.L.P. et al (the Big Star Lawsuit) and Pemex Exploración y Producción v. Murphy Energy et al (the Murphy Lawsuit). In two cases filed in the Texas Southern District Court in May 2011 and April 2012, Pemex Exploración y Producción (PEP) alleges that certain parties stole condensate from pipelines and gathering stations and conspired with U.S.

companies (primarily in Texas) to import and market the stolen condensate. PEP does not allege that Plains was part of any conspiracy, but that it dealt in the condensate only after it had been obtained by others and resold to Plains Marketing, L.P. PEP seeks actual damages, attorney s fees, and statutory penalties from Plains Marketing, L.P. In February 2013, the Court granted Plains Marketing, L.P. s motion to be dismissed from the Murphy Lawsuit. In October 2013, the Court issued an order in the Big Star Lawsuit granting summary judgment in favor of Plains Marketing, L.P. with respect to all of PEP s remaining claims against Plains Marketing, L.P. In February 2014, the Court affirmed its order granting summary judgment in favor of Plains Marketing, L.P. in the Big Star Lawsuit, denied PEP s motion for reconsideration, severed the case against Plains from the other defendants and issued a final judgment dismissing all claims against Plains. The time for PEP to appeal the final judgment in both cases has lapsed. Plains motion to sever Plains from the remainder of the defendants in the Murphy Lawsuit in order to obtain a final judgment has been granted.

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In the Matter of Rancho LPG Holdings LLC, Respondent. In May 2014, Rancho LPG Holdings LLC (Rancho), a wholly owned subsidiary of PAA, entered into a Consent Agreement and Final Order (Consent Agreement) with the EPA regarding alleged violations of certain risk management plan regulations under the federal Clean Air Act at Rancho s LPG storage facility in San Pedro, California. The allegations, which Rancho disputed, arose from inspections of the facility by the EPA during 2010 and 2011. Pursuant to the Consent Agreement, Rancho agreed to pay a civil penalty of $260,000; however, no injunctive relief was sought by the EPA. Further, the Rancho facility was determined, as of the date of the Consent Agreement, to be in full compliance with the regulations that were the subject of the alleged violations.

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 June 30, 2014, our estimated undiscounted reserve for environmental liabilities totaled approximately $92 million, of which approximately $13 million was classified as short-term and approximately $79 million was classified as long-term. At December 31, 2013, our estimated undiscounted reserve for environmental liabilities totaled approximately $93 million, of which approximately $11 million was classified as short-term and approximately $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 June 30, 2014 and December 31, 2013, we had recorded receivables totaling approximately $8 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.

Rainbow Pipeline Release. During April 2011, we experienced a crude oil release of approximately 28,000 barrels of crude oil on a remote section of our Rainbow Pipeline located in Alberta, Canada. Since the release and through June 30, 2014, we spent approximately $70 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of June 30, 2014, we did not have any material outstanding liabilities or insurance receivables relating to this release. On February 26, 2013, the Alberta Energy Regulator (AER) issued four enforcement actions against PMC for failure to comply with certain regulatory requirements in connection with the release, including requirements related to operations and maintenance procedures, leak detection and response, backfill and compaction procedures and emergency response plan testing. PMC has taken and continues to take appropriate actions necessary to respond to and comply with the enforcement actions set forth in the report, including the implementation of additional risk assessment procedures and other actions designed to minimize the risk that similar incidents occur in the future and enhance the effectiveness of PMC s response to any such future incidents. In addition, on April 23, 2013, the Alberta Crown Prosecutor filed charges under the Alberta Environmental Protection and Enhancement Act against PMC relating to the release. PMC settled these charges in July 2014 for $450,000 CAD.

Rangeland Pipeline Release. During June 2012, we experienced a crude oil release on a section of our Rangeland Pipeline located near Sundre, Alberta, Canada. Approximately 3,000 barrels were released into the Red Deer River and were contained downstream in the Gleniffer Reservoir. Remediation activities in the reservoir area were completed by June 30, 2012, remediation of the remaining impacted areas of government-owned lands was completed by September 30, 2012 and interim closure, in respect of those lands, was received from the applicable regulatory agencies. A long-term monitoring plan has been developed and implemented in accordance with regulatory requirements. Through June 30, 2014, we spent approximately $47 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities. On July 4, 2013, the AER issued four enforcement actions against PMC citing failure to inspect water crossings, failure to complete an engineering assessment to determine suitability of continued operation of the Rangeland Pipeline, failure to maintain updated emergency response plans, and failure to conduct regular public awareness programs. In addition, on May 30, 2014, the Alberta Crown Prosecutor and Public Prosecution Services of Canada filed charges under the Alberta Environmental Protection and Enhancement Act and Canadian Federal Fisheries Act against PMC relating to the release. PMC settled all of such charges in July 2014 for an aggregate of $850,000 CAD.

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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 June 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. 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 June 30, 2014				
Revenues (1):				
External Customers	$ 195	$ 144	$ 10,856	$ 11,195
Intersegment (2)	217	133	4	354
Total revenues of reportable segments	$ 412	$ 277	$ 10,860	$ 11,549
Equity earnings in unconsolidated entities	$ 23	$	$	$ 23
Segment profit (3) (4)	$ 221	$ 134	$ 133	$ 488
Maintenance capital	$ 42	$ 5	$ 1	$ 48
Three Months Ended June 30, 2013				
Revenues:				
External Customers	$ 165	$ 197	$ 9,933	$ 10,295
Intersegment (2)	200	151	1	352
Total revenues of reportable segments	$ 365	$ 348	$ 9,934	$ 10,647
Equity earnings in unconsolidated entities	$ 11	$	$	$ 11
Segment profit (3) (4)	$ 160	$ 149	$ 176	$ 485

Maintenance capital	$	23	$	11	$	5	$	39

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	Transportation	Facilities	Supply and Logistics	Total
Six Months Ended June 30, 2014				
Revenues (1):				
External Customers	$ 376	$ 301	$ 22,201	$ 22,878
Intersegment (2)	422	275	27	724
Total revenues of reportable segments	$ 798	$ 576	$ 22,228	$ 23,602
Equity earnings in unconsolidated entities	$ 44	$	$	$ 44
Segment profit (3) (4)	$ 427	$ 288	$ 382	$ 1,097
Maintenance capital	$ 76	$ 15	$ 4	$ 95
Six Months Ended June 30, 2013				
Revenues:				
External Customers	$ 338	$ 420	$ 20,157	$ 20,915
Intersegment (2)	394	283	1	678
Total revenues of reportable segments	$ 732	$ 703	$ 20,158	$ 21,593
Equity earnings in unconsolidated entities	$ 23	$	$	$ 23
Segment profit (3) (4)	$ 323	$ 300	$ 610	$ 1,233
Maintenance capital	$ 55	$ 18	$ 9	$ 82

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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 approximately $5 million for each of the three months ended June 30, 2014 and 2013 and approximately $7 million and $10 million for the six months ended June 30, 2014 and 2013, respectively.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Segment profit	$ 488	$ 485	$ 1,097	$ 1,233
Depreciation and amortization	(100)	(91)	(196)	(173)
Interest expense, net	(82)	(75)	(161)	(152)
Other income/(expense), net	4	(1)	2	(1)

Income before tax		310		318		742		907
Income tax expense		(22)		(18)		(70)		(70)
Net income		288		300		672		837
Net income attributable to noncontrolling interests		(1)		(8)		(1)		(16)
Net income attributable to PAA	$	287	$	292	$	671	$	821

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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 June 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 six months ended June 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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$ 351	$ 424	$ 443	$ 694
Purchases and related costs	$ 209	$ 214	$ 468	$ 375

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

	June 30, 2014	December 31, 2013
Trade accounts receivable and other receivables	$ 460	$ 133
Accounts payable	$ 321	$ 181

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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 six months of 2014, we recognized net income attributable to PAA of approximately $671 million, or $1.18 per diluted limited partner unit, as compared to net income attributable to PAA of approximately $821 million, or $1.84 per diluted limited partner unit, recognized during the first six months of 2013. These decreases were primarily driven by less favorable crude oil market conditions experienced during the 2014 period, most notably during the comparative first quarter period, which provided fewer opportunities for above-baseline crude oil margins in our Supply and Logistics segment. 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 several months of 2014. However, such decreases were partially offset by favorable results from our Transportation segment, largely due to the continued increase in North American crude oil production and our related, recently completed internal growth projects.

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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):

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Acquisition capital	$ 2	$ 1
Internal growth projects	1,012	830
Maintenance capital	95	82
Total	$ 1,109	$ 913

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	$480
Cactus Pipeline	350
Rail Terminal Projects (1)	220
Ft. Sask Facility Projects / NGL Line	135
Western Oklahoma Extension	80
Eagle Ford JV Project	65
Mississippian Lime Pipeline	50
White Cliffs Expansion	40
Line 63 Reactivation	35
Natural Gas Storage Expansions	35
Other Projects	460
	$1,950
Potential Adjustments for Timing / Scope Refinement (2)	-$100 + $100
Total Projected Expansion Capital Expenditures	$1,850 - $2,050

(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

Analysis of 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 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 amounts):

	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
	2014	2013	$	%	2014	2013	$	%
Transportation segment profit	$ 221	$ 160	$ 61	38%	$ 427	$ 323	$ 104	32%
Facilities segment profit	134	149	(15)	(10)%	288	300	(12)	(4)%
Supply and Logistics segment profit	133	176	(43)	(24)%	382	610	(228)	(37)%
Total segment profit	488	485	3	1%	1,097	1,233	(136)	(11)%
Depreciation and amortization	(100)	(91)	(9)	(10)%	(196)	(173)	(23)	(13)%
Interest expense, net	(82)	(75)	(7)	(9)%	(161)	(152)	(9)	(6)%
Other income/(expense), net	4	(1)	5	500%	2	(1)	3	300%
Income tax expense	(22)	(18)	(4)	(22)%	(70)	(70)		%
Net income	288	300	(12)	(4)%	672	837	(165)	(20)%
Net income attributable to noncontrolling interests	(1)	(8)	7	88%	(1)	(16)	15	94%
Net income attributable to PAA	$ 287	$ 292	$ (5)	(2)%	$ 671	$ 821	$ (150)	(18)%
Net income attributable to PAA:								
Basic net income per limited partner unit	$ 0.45	$ 0.58	$ (0.13)	(22)%	$ 1.19	$ 1.85	$ (0.66)	(36)%
Diluted net income per limited partner unit	$ 0.45	$ 0.57	$ (0.12)	(21)%	$ 1.18	$ 1.84	$ (0.66)	(36)%
Basic weighted average units outstanding	365	340	25	7%	363	338	25	7%
Diluted weighted average units outstanding	367	342	25	7%	365	341	24	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):

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Net income	$ 288	$ 300	$ (12)	(4)%	$ 672	$ 837	$ (165)	(20)%
Add:								
Depreciation and amortization	100	91	9	10%	196	173	23	13%
Income tax expense	22	18	4	22%	70	70		%
Interest expense, net	82	75	7	9%	161	152	9	6%
EBITDA	$ 492	$ 484	$ 8	2%	$ 1,099	$ 1,232	$ (133)	(11)%
Selected Items Impacting Comparability of EBITDA								
Gains/(losses) from derivative activities net of inventory valuation adjustments (1)	$ (14)	$ 26	$ (40)	(154)%	$ 50	$ 50	$	%
Equity-indexed compensation expense (2)	(17)	(16)	(1)	(6)%	(36)	(39)	3	8%
Net gain/(loss) on foreign currency revaluation (3)	11	(4)	15	375%	6	4	2	50%
Selected Items Impacting Comparability of EBITDA	$ (20)	$ 6	$ (26)	(433)%	$ 20	$ 15	$ 5	33%
EBITDA	$ 492	$ 484	$ 8	2%	$ 1,099	$ 1,232	$ (133)	(11)%
Selected Items Impacting Comparability of EBITDA	20	(6)	26	433%	(20)	(15)	(5)	(33)%
Adjusted EBITDA	$ 512	$ 478	$ 34	7%	$ 1,079	$ 1,217	$ (138)	(11)%
Adjusted EBITDA	$ 512	$ 478	$ 34	7%	$ 1,079	$ 1,217	$ (138)	(11)%
Interest expense, net	(82)	(75)	(7)	(9)%	(161)	(152)	(9)	(6)%
Maintenance capital (4)	(48)	(39)	(9)	(23)%	(95)	(82)	(13)	(16)%
Current income tax expense	(16)	(8)	(8)	(100)%	(52)	(53)	1	2%
Equity earnings in unconsolidated entities, net of distributions	2	(1)	3	300%	7	(1)	8	800%
Distributions to noncontrolling interests (5)	(1)	(13)	12	92%	(2)	(25)	23	92%
Implied DCF	$ 367	$ 342	$ 25	7%	$ 776	$ 904	$ (128)	(14)%
Less: Distributions paid (5)	(360)	(296)			(704)	(581)		
DCF Excess/(Shortage) (6)	$ 7	$ 46			$ 72	$ 323		

(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 six months ended June 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.

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:

Operating Results (1)	**Three Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**		**Six Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**	
(in millions, except per barrel data)	**2014**	**2013**	**$**	**%**	**2014**	**2013**	**$**	**%**
Revenues								
Tariff activities	$ 356	$ 310	$ 46	15%	$ 691	$ 629	$ 62	10%
Trucking	56	55	1	2%	107	103	4	4%
Total Transportation revenues	412	365	47	13%	798	732	66	9%

Costs and Expenses								
Trucking costs	(41)	(39)	(2)	(5)%	(78)	(74)	(4)	(5)%
Field operating costs (excluding equity-indexed compensation expense)	(137)	(138)	1	1%	(265)	(270)	5	2%
Equity-indexed compensation expense - operations (2)	(5)	(4)	(1)	(25)%	(10)	(13)	3	23%
Segment general and administrative expenses (3) (excluding equity- indexed compensation expense)	(21)	(26)	5	19%	(43)	(49)	6	12%
Equity-indexed compensation expense - general and administrative (2)	(10)	(9)	(1)	(11)%	(19)	(26)	7	27%
Equity earnings in unconsolidated entities	23	11	12	109%	44	23	21	91%
Segment profit	$ 221	$ 160	$ 61	38%	$ 427	$ 323	$ 104	32%
Maintenance capital	$ 42	$ 23	$ (19)	(83)%	$ 76	$ 55	$ (21)	(38)%
Segment profit per barrel	$ 0.62	$ 0.49	$ 0.13	27%	$ 0.61	$ 0.49	$ 0.12	24%

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Average Daily Volumes (in thousands of barrels per day) (4)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %
Tariff activities								
Crude Oil Pipelines								
All American	38	38		%	36	39	(3)	(8)%
Bakken Area Systems	145	130	15	12%	138	127	11	9%
Basin / Mesa	714	680	34	5%	729	702	27	4%
Capline	121	158	(37)	(23)%	123	157	(34)	(22)%
Eagle Ford Area Systems	209	74	135	182%	199	61	138	226%
Line 63 / Line 2000	106	108	(2)	(2)%	116	113	3	3%
Manito	44	46	(2)	(4)%	44	46	(2)	(4)%
Mid-Continent Area Systems	360	282	78	28%	338	287	51	18%
Permian Basin Area Systems	759	548	211	39%	759	513	246	48%
Rainbow	108	125	(17)	(14)%	114	124	(10)	(8)%
Rangeland	65	56	9	16%	67	62	5	8%
Salt Lake City Area Systems	130	131	(1)	(1)%	131	133	(2)	(2)%
South Saskatchewan	58	33	25	76%	61	46	15	33%
White Cliffs	24	21	3	14%	24	21	3	14%
Other	745	739	6	1%	703	737	(34)	(5)%
NGL Pipelines								
Co-Ed	55	51	4	8%	56	54	2	4%
Other	123	165	(42)	(25)%	119	186	(67)	(36)%
Refined Products Pipelines		110	(110)	(100)%		105	(105)	(100)%
Tariff activities total	3,804	3,495	309	9%	3,757	3,513	244	7%
Trucking	127	108	19	18%	129	109	20	18%
Transportation segment total	3,931	3,603	328	9%	3,886	3,622	264	7%

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

(2) Equity-indexed compensation expense shown in the table above includes expenses associated with awards that will or may be settled in units and awards that will or may be settled in cash. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2013 Annual Report on Form 10-K for additional discussion regarding our equity-indexed compensation plans.

(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.

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 six months ended June 30, 2014 compared to the three and six months ended June 30, 2013. Our Transportation segment results for the comparative periods were impacted by the following:

- 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 six months ended June 30, 2014 over the comparable 2013 periods were most notably on our Permian Basin, Eagle Ford and Mid-Continent Area Systems and our Basin and Mesa pipelines. We estimate that increased production combined with our recently completed internal growth projects increased revenues by over $25 million and $50 million for the three and six months ended June 30, 2014, respectively, compared to the three and six months ended June 30, 2013.

- Loss Allowance Revenue   As is common in the 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 approximately $20 million and $30 million, respectively, for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 driven primarily by higher volumes, as well as a higher average realized price per barrel (including the impact of gains and losses from derivative-related activities).

- 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 approximately $11 million and $18 million for the three and six months ended June 30, 2014, respectively, compared to the three and six months ended June 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 six months ended June 30, 2014, our revenues were lower by approximately $10 million and $20 million, respectively, and volumes were lower by 110,000 and 105,000 barrels per day, respectively, as compared to the three and six months ended June 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 June 30, 2014 and 2013 were $1.09 CAD: $1.00 USD and $1.02 CAD: $1.00 USD, respectively. The average CAD to USD exchange rates for the six months ended June 30, 2014 and 2013 were $1.10 CAD: $1.00 USD and $1.02 CAD: $1.00 USD, respectively. Therefore, revenues from our Canadian pipeline systems and trucking operations were unfavorably impacted by approximately $6 million and $15 million for the three and six months ended June 30, 2014, respectively, compared to the three and six months ended June 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 six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 were (i) decreased volumes and revenues on certain of our NGL pipelines due to (a) the discontinuation of an agreement in 2014 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, (ii) decreased volumes and revenues on the Capline pipeline due to refinery turnaround in the first half of 2014, (iii) 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 quarter of 2013 due to high river flow rates and flooding in the surrounding area and (iv) a net decrease in volumes on our crude oil pipelines included in   Other   in the table above for the six month comparable period, a majority of which was related to (a) pipelines subject to long-term lease commitments with annual service payments whereby volumes may fluctuate, but such fluctuations did not have a meaningful impact on revenue and (b) pipelines impacted by third-party connection shut-downs and line repairs, which also did not have a significant impact on revenues for the period, partially offset by incremental volumes and revenues from our Gulf Coast pipeline, which was placed into service in April 2014.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expenses) decreased during the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 due to higher environmental remediation costs in 2013, partially offset by increases due to (i) a change in classification of certain costs from General and Administrative expenses, and (ii) a general increase in expenses due to growth.

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General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) decreased during the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 primarily due to (i) a change in classification of certain costs to Field Operating Costs and (ii) higher costs in 2013 associated with the sale of certain refined products pipeline systems and related assets.

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 six months ended June 30, 2014 compared to the three and six months ended June 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 June 30, 2014 compared to the same period in 2013, primarily due to the impact of the increase in unit price during the period compared to a decrease in unit price for the same period in 2013.

Consolidated equity-indexed compensation expense decreased for the six months ended June 30, 2014 compared to the same period in 2013, primarily due to a less significant impact of the increase in unit price during the six months ended June 30, 2014 compared to the same period in 2013. 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 six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 was largely due to increased throughput on the Eagle Ford joint venture pipeline as a result of increased production, as discussed above.

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:

Operating Results (1)	**Three Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**		**Six Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**	
(in millions, except per barrel data)	**2014**	**2013**	**$**	**%**	**2014**	**2013**	**$**	**%**
Revenues	$ 277	$ 262	$ 15	6%	$ 576	$ 529	$ 47	9%

Natural gas sales (2)		86	(86)	(100)%		174	(174)	(100)%
Storage related costs (natural gas related)	(12)	(3)	(9)	(300)%	(38)	(9)	(29)	(322)%
Natural gas sales costs (2)		(80)	80	100%		(165)	165	100%
Field operating costs (excluding equity-indexed compensation expense)	(106)	(94)	(12)	(13)%	(204)	(180)	(24)	(13)%
Equity-indexed compensation expense - operations (3)	(2)		(2)	N/A	(2)	(1)	(1)	(100)%
Segment general and administrative expenses (4) (excluding equity- indexed compensation expense)	(16)	(16)		%	(29)	(32)	3	9%
Equity-indexed compensation expense - general and administrative (3)	(7)	(6)	(1)	(17)%	(15)	(16)	1	6%
Segment profit	$ 134	$ 149	$ (15)	(10)%	$ 288	$ 300	$ (12)	(4)%
Maintenance capital	$ 5	$ 11	$ 6	55%	$ 15	$ 18	$ 3	17%
Segment profit per barrel	$ 0.37	$ 0.41	$ (0.04)	(10)%	$ 0.40	$ 0.42	$ (0.02)	(5)%

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	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
Volumes (5)	**2014**	**2013**	**Volumes**	**%**	**2014**	**2013**	**Volumes**	**%**
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	94	95	(1)	(1)%	95	94	1	1%
Rail load / unload volumes (average volumes in thousands of barrels per day)	224	231	(7)	(3)%	227	223	4	2%
Natural gas storage (average monthly capacity in billions of cubic feet)	97	97		%	97	95	2	2%
NGL fractionation (average volumes in thousands of barrels per day)	86	90	(4)	(4)%	89	95	(6)	(6)%
Facilities segment total (average monthly volumes in millions of barrels) (6)	120	121	(1)	(1)%	121	120	1	1%

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

(2) 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.

(3) Equity-indexed compensation expense shown in the table above includes expenses associated with awards that will or may be settled in units and awards that will or may be settled in cash. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2013 Annual Report on Form 10-K for additional discussion regarding our equity-indexed compensation plans.

(4) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

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

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

convert to monthly volumes in millions; and (iv) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

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

Operating Revenues and Volumes. As noted in the table above, our Facilities segment revenues, less storage related costs, for the three months ended June 30, 2014 were in line with our results as compared to the same period of 2013, while our segment revenues, less storage related costs, increased slightly for the six months ended June 30, 2014 compared to the six months ended June 30, 2013. Total volumes were relatively consistent over the periods presented. The significant variances in revenues between the comparative periods are discussed below:

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- NGL Fractionation, NGL Storage and Natural Gas Processing Activities Increases in revenues from our NGL fractionation and storage and natural gas processing activities of approximately $5 million and $21 million, respectively, for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013, were largely driven by higher facility fee revenues due to rate increases at certain of our storage and fractionation facilities.

These increases in NGL revenues include estimated unfavorable foreign currency impacts of approximately $5 million and $11 million for the three and six months ended June 30, 2014, respectively, as compared to the three and six months ended June 30, 2013 due to the depreciation of the Canadian dollar relative to the U.S. dollar. The average CAD to USD exchange rates for the three months ended June 30, 2014 and 2013 were $1.09 CAD: $1.00 USD and $1.02 CAD: $1.00 USD, respectively. The average CAD to USD exchange rates for the six months ended June 30, 2014 and 2013 were $1.10 CAD: $1.00 USD and $1.02 CAD: $1.00 USD, respectively.

- Natural Gas Storage Operations Net revenues from our natural gas storage operations decreased by approximately $9 million and $21 million, respectively, for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013. The decrease for the three-month 2014 period was primarily due to decreased storage rates on contracts that renewed or replaced expiring contracts. The six-month 2014 period was further unfavorably impacted by costs incurred in our natural gas storage activities to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced during the first several months of 2014.

- Rail Terminals Revenues from rail load and unload activities increased by approximately $3 million for the six months ended June 30, 2014 compared to the same period in 2013, respectively. This increase was primarily due to new rail terminals that came online in the fourth quarter of 2013, partially offset by the unfavorable impact of rail congestion and weather-related issues at certain of our terminals. For the three month comparable period, the increase in revenues from the new rail terminals was offset by decreased volumes into our St. James facility as well as the unfavorable impact of congestion, resulting in relatively consistent revenues for the three months ended June 30, 2014 compared to the three months ended June 30, 2013.

- Crude Oil Storage and Condensate Processing Activities Increased revenues from our crude oil storage and condensate processing activities of approximately $4 million and $5 million, respectively, for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 were largely driven by the start-up and subsequent expansion of our Eagle Ford processing facility and increased throughput and expansions at certain of our Mid-Continent and Gulf Coast storage facilities. However, such results were partially offset by reduced revenues from storage facilities in California and the East Coast due to decreased demand, as well as the reclassification of certain of our Canadian storage facilities to our Transportation segment during the second quarter of 2014.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expenses) increased during the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 due to (i) a change in classification of certain costs from General and Administrative expenses, (ii) increased utility costs due primarily to higher power and gas prices and (iii) increased maintenance and repairs costs.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) remained relatively consistent for the three months ended June 30, 2014 compared to the three months ended June 30, 2013 and decreased during the comparative six-month periods. These results reflect the net impact of a decrease in general and administrative expenses due to a change in classification of certain costs to Field Operating Costs during the 2014 periods partially offset by increased expenses resulting from overall growth in the segment.

Equity-Indexed Compensation Expense. On a consolidated basis across all segments, equity-indexed compensation expense increased for the three months ended June 30, 2014 over the comparable 2013 period, and decreased for the six months ended June 30, 2014 compared to the six months ended June 30, 2013. See the discussion regarding such variances under Transportation Segment above. Also, 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.

Supply and Logistics Segment

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

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

Operating Results (1) (2) (in millions, except per barrel data)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Favorable/ (Unfavorable) Variance $	Favorable/ (Unfavorable) Variance %	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Favorable/ (Unfavorable) Variance $	Favorable/ (Unfavorable) Variance %
Revenues	$ 10,860	$ 9,934	$ 926	9%	$ 22,228	$ 20,158	$ 2,070	10%
Purchases and related costs (3)	(10,578)	(9,614)	(964)	(10)%	(21,553)	(19,249)	(2,304)	(12)%
Field operating costs (excluding equity- indexed compensation expense)	(112)	(109)	(3)	(3)%	(218)	(224)	6	3%
Equity-indexed compensation expense - operations (4)	(1)	(1)		%	(2)	(2)		%
Segment general and administrative expenses (5) (excluding equity- indexed compensation expense)	(27)	(27)		%	(53)	(53)		%
Equity-indexed compensation expense - general and administrative (4)	(9)	(7)	(2)	(29)%	(20)	(20)		%
Segment profit	$ 133	$ 176	$ (43)	(24)%	$ 382	$ 610	$ (228)	(37)%
Maintenance capital	$ 1	$ 5	$ 4	80%	$ 4	$ 9	$ 5	56%
Segment profit per barrel	$ 1.37	$ 1.89	$ (0.52)	(28)%	$ 1.89	$ 3.11	$ (1.22)	(39)%

Average Daily Volumes (in thousands of barrels per day)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Favorable/ (Unfavorable) Variance Volumes	Favorable/ (Unfavorable) Variance %	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Favorable/ (Unfavorable) Variance Volumes	Favorable/ (Unfavorable) Variance %
Crude oil lease gathering purchases	931	853	78	9%	912	855	57	7%
NGL sales	139	160	(21)	(13)%	205	221	(16)	(7)%
Waterborne cargos		7	(7)	(100)%		6	(6)	(100)%
Supply and Logistics segment total	1,070	1,020	50	5%	1,117	1,082	35	3%

(1) Revenues and costs include intersegment amounts.

(2) Prior to January 1, 2014, natural gas sales revenues and costs attributable to the activities performed by our natural gas storage commercial optimization group were reported in the Facilities segment.

(3) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately $5 million and $7 million for the three and six months ended June 30, 2014 and approximately $5 million and $10 million for the three and six months ended June 30, 2013, respectively.

(4) Equity-indexed compensation expense shown in the table above includes expenses associated with awards that will or may be settled in units and awards that will or may be settled in cash. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2013 Annual Report on Form 10-K for additional discussion regarding our equity-indexed compensation plans.

(5) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

The NYMEX West Texas Intermediate benchmark price of crude oil ranged from approximately $99 to $108 per barrel and $86 to $99 per barrel during the three months ended June 30, 2014 and 2013, respectively, and from $91 to $108 per barrel and $86 to $99 per barrel during the six months ended June 30, 2014 and 2013, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for the three and six months ended June 30, 2014 relative to the comparative periods, primarily resulting from increases in crude oil volumes in 2014, as well as increases in prices, primarily during the comparative three-month period.

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Generally, we expect a base level of earnings from our Supply and Logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. Also, our NGL marketing operations are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on NGL demand and thus our financial performance.

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

Operating Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs, excluding gains and losses from certain derivative activities (see the Impact from Certain Derivative Activities section below), were relatively consistent for the three months ended June 30, 2014 compared to the three months ended June 30, 2013, while such results decreased year-over-year for the six month comparative periods presented. The following factors impacted revenues and volumes in the comparative periods:

• North American Crude Oil Production and Related Market Economics - The significant increase in oil and liquids-rich gas production growth in North America has generally created regional supply and demand imbalances, due to the lack of sufficient infrastructure to support the movement of such production, which increased certain crude oil location differentials. The lack of existing pipeline takeaway capacity and associated logistical challenges has created market conditions that provided opportunities to capture above-baseline margins in our supply and logistics activities over the last few years.

The favorable impact of widening differentials in the second quarter of 2014 led to an increase in net revenues from our crude oil supply and logistics activities for the three months ended June 30, 2014 compared to the three months ended June 30, 2103. Net revenues from our crude oil supply and logistics activities decreased for the six months ended June 30, 2014 compared to the six months ended June 30, 2013, as there were fewer opportunities to capture above-baseline margins.

We believe the fundamentals of our business remain strong as lease-gathered volumes for the three and six month periods ended June 30, 2014 increased by 9% and 7%, respectively, as compared to volumes in the same three and six month periods in 2013. However, as the midstream infrastructure continues to be developed, we believe a normalization of margins will continue to occur as the logistics challenges are addressed. (See Items 1 and 2 Business and Properties Description of Segments and Associated Assets Supply and Logistics Segment Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model included in Part I of our 2013 Annual Report on Form 10-K for further discussion regarding our business model, including diversification and utilization of our asset base among varying demand- and supply-driven markets.)

• NGL Marketing Operations Revenues and volumes from our NGL marketing operations decreased during the three and six months ended June 30, 2014 as compared to the three and six months ended June 30, 2013. These decreases were driven by (i) less favorable market conditions, most notably during the second quarter of 2014, (ii) higher costs during the 2014 periods, primarily due to increased facility fees, and (iii) lower butane supply during the three months ended June 30, 2014.

• Natural Gas Storage Commercial Optimization - Our natural gas storage commercial optimization activities for the six months ended June 30, 2014 were unfavorably impacted by costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced during the first quarter of 2014.

Impact from Certain Derivative Activities. The mark-to-market valuation of certain of our derivative activities impacted our net revenues as shown in the table below (in millions):

	Three Months Ended June 30,			**Six Months Ended June 30,**		
	2014	**2013**	**Variance**	**2014**	**2013**	**Variance**
Gains/(losses) from certain derivative activities (1)	$ (15)	$ 27	$ (42)	$ 51	$ 51	$

(1) Includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. These amounts are reduced by the net impact of inventory valuation adjustments attributable to inventory hedged by the related derivative and gains recognized in later periods on physical sales of inventory that was previously written down. See Note 10 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and risk management activities.

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Field Operating Costs. The increase in field operating costs (excluding equity-indexed compensation expenses) for the three months ended June 30, 2014 compared to the three months ended June 30, 2013 was primarily due to an increase in trucking costs associated with higher crude oil lease gathered volumes.

Field operating costs (excluding equity-indexed compensation expenses) decreased for the six months ended June 30, 2014 compared to the six months ended June 30, 2013 primarily due to a decrease in third-party transportation costs in the first quarter of 2014 as compared to the first quarter of 2013.

Equity-Indexed Compensation Expense. On a consolidated basis across all segments, equity-indexed compensation expense increased for the three months ended June 30, 2014 over the comparable 2013 period, and decreased for the six months ended June 30, 2014 compared to the six months ended June 30, 2013. See the discussion regarding such variances under Transportation Segment above. Also, 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.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense increased by approximately $9 million and $23 million for the three and six months ended June 30, 2014, respectively, over the three and six months ended June 30, 2013. These increases in depreciation and amortization expense in the 2014 periods over the comparable 2013 periods were primarily due to an acceleration of depreciation on certain pipeline assets to reflect a change in their estimated useful lives, as well as various internal growth projects completed since June 30, 2013.

Interest Expense

Interest expense increased by approximately $7 million and $9 million for the three and six months ended June 30, 2014, respectively, over the three and six months ended June 30, 2013 as a result of higher average debt outstanding during the 2014 periods, primarily due to (i) our August 2013 issuance of $700 million, 3.85% senior notes and (ii) our April 2014 issuance of $700 million, 4.70% senior notes, partially offset by the maturity of our $250 million, 5.63% senior notes in December 2013.

Other Income/(Expense), Net

Other income/(expense), net in each of the periods presented was primarily comprised of foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with our intercompany notes and the impact of related foreign currency hedges.

Income Tax Expense

Income tax expense increased by approximately $4 million for the three months ended June 30, 2014 compared to the three months ended June 30, 2013, primarily as a result of higher year over year Canadian tax expense.

Net Income attributable to Noncontrolling Interests

Net income attributable to noncontrolling interests decreased for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 as a result of our completion of the PNG Merger on December 31, 2013, pursuant to which we acquired all of the noncontrolling interests in PNG.

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Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities, (ii) borrowings under the commercial paper program or credit facilities and (iii) funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under the commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities. As of June 30, 2014, we had a working capital deficit of approximately $255 million and approximately $2.2 billion of liquidity available to meet our ongoing operating, investing and financing needs as noted below (in millions):

		As of June 30, 2014
Availability under PAA senior unsecured revolving credit facility (1)	$	1,586
Availability under PAA senior secured hedged inventory facility (1)		1,376
Less: Amounts outstanding under PAA commercial paper program		(760)
Subtotal		2,202
Cash and cash equivalents		27
Total	$	2,229

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

We believe that we have, and will continue to have, the ability to access the commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Risk Factors in Item 1A of our 2013 Annual Report on Form 10-K for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities, which provide the backstop for the commercial paper program, is subject to ongoing compliance with covenants. As of June 30, 2014, we were in compliance with all such covenants.

Cash Flow from Operating Activities

For a comprehensive discussion of the primary drivers of cash flow from operating activities, including the impact of varying market conditions and the timing of settlement of our derivative activities, see Liquidity and Capital Resources-Cash Flow from Operating Activities under Item 7 of our 2013 Annual Report on Form 10-K.

Net cash provided by operating activities for the first six months of 2014 was approximately $963 million, primarily resulting from earnings from our operations. Additionally, we decreased our inventory levels (including margin balances required as part of our hedging activities) that were funded by our short-term debt, resulting in a positive impact on our cash provided by operating activities.

Net cash provided by operating activities for the first six months of 2013 of approximately $1.3 billion also resulted primarily from earnings from our operations. In addition, we decreased the amount of our inventory during the first half of 2013, primarily due to the sale of NGL inventory related to product demand caused by increases in (i) heating requirements during the extended 2013 winter season, (ii) export activity that reduced overall product availability in the market and (iii) petrochemical demand, as well as the sale of crude oil inventory that had been stored during the contango market. The net proceeds received from liquidation of such inventory during the quarter were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities.

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Acquisitions and Capital Expenditures

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

2014 Capital Expansion Projects. See Acquisitions and Internal Growth Projects for detail of our projected capital expenditures for the year ending December 31, 2014. We expect the majority of funding for our 2014 capital program will be provided by borrowings under the commercial paper program, our credit facilities and cash flow in excess of partnership distributions, as well as through our access to the capital markets for equity and debt as we deem necessary.

Acquisitions. The price of acquisitions includes cash paid, assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the period. Historically, we have financed acquisitions primarily with cash generated by operations and the financing activities discussed below.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding acquisitions, internal capital projects and refinancing our debt maturities, as well as short-term working capital and hedged inventory borrowings related to our NGL business and contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under the commercial paper program or the credit facilities, as well as payment of distributions to our unitholders and general partner.

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). All issuances of equity securities associated with our continuous offering program, as discussed further below, have been issued pursuant to the Traditional Shelf. At June 30, 2014, we had approximately $1.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs.

Continuous Offering Program. During the six months ended June 30, 2014, we issued an aggregate of approximately 8.1 million common units under our continuous offering program, generating net proceeds of approximately $453 million, including our general partner s proportionate capital contribution of approximately $9 million. The net proceeds from these sales were used for general partnership purposes.

Credit Agreements, Commercial Paper Program and Indentures. Our credit agreements (which impact our ability to access our commercial paper program because they provide the backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We were in compliance with the covenants contained in our credit agreements and indentures as of June 30, 2014.

During the six months ended June 30, 2014 and 2013, we had net repayments on our credit agreements and commercial paper program of approximately $344 million and $186 million, respectively. The net repayments during both periods resulted primarily from cash flow from operating activities, including sales of inventory that was liquidated during the periods, as well as cash received from our debt and equity activities.

In April 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. We used the net proceeds from this offering of approximately $691 million, after deducting the underwriting discount and offering expenses, to repay outstanding borrowings under our commercial paper program and for general partnership purposes.

Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests

Distributions to our unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On August 14, 2014 we will pay a distribution of $0.6450 per limited partner unit, which represents a 9.8% increase over the distribution we paid in August 2013. See Note 8 to our condensed consolidated financial statements for details of distributions paid. Also, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash Distribution Policy included in our 2013 Annual Report on Form 10-K for additional discussion on distributions.

Distributions to noncontrolling interests. We paid approximately $1 million and $24 million for distributions to noncontrolling interests during the six months ended June 30, 2014 and 2013, respectively. The decrease in amounts paid is due to our completion of the purchase of all of the noncontrolling interests in PNG on December 31, 2013.

We believe that we have sufficient liquid assets, cash flow from operating activities and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow. A prolonged material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

For a discussion of contingencies that may impact us, see Note 11 to our condensed consolidated financial statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years with a limited number of contracts extending up to approximately ten years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with our counterparties (including giving effect to netting buy/sell contracts and those subject to a net settlement arrangement). We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of June 30, 2014 (in millions):

	Remainder of 2014	2015	2016	2017	2018	2019 and Thereafter	Total
Long-term debt, including related interest payments (1)	$ 193	$ 927	$ 533	$ 728	$ 900	$ 8,888	$ 12,169
Leases (2)	76	143	135	112	88	416	970
Other obligations (3)	122	125	89	62	45	221	664
Subtotal	391	1,195	757	902	1,033	9,525	13,803
Crude oil, natural gas, NGL and other purchases (4)	7,310	7,111	6,303	4,898	2,766	8,151	36,539
Total	$ 7,701	$ 8,306	$ 7,060	$ 5,800	$ 3,799	$ 17,676	$ 50,342

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

(2) Leases are primarily for (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements and (iii) commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity-method investments. Excludes a non-current liability of approximately $4 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during June 2014. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Additionally, we issue letters of credit to support insurance programs and construction activities. At June 30, 2014 and December 31, 2013, we had outstanding letters of credit of approximately $38 million and $41 million, respectively.

Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements

See Note 2 to our condensed consolidated financial statements.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates under Item 7 of our 2013 Annual Report on Form 10-K.

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and st regarding our business strategy, plans and objectives for future operations. The absence of such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

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

- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);

- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

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

- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;

- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;

- tightened capital markets or other factors that increase our cost of capital or limit our access to capital;

- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- the currency exchange rate of the Canadian dollar;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- shortages or cost increases of supplies, materials or labor;
- the effectiveness of our risk management activities;
- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;
- non-utilization of our assets and facilities;
- the effects of competition;
- increased costs or lack of availability of insurance;

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

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

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

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

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

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risk Factors discussed in Item 1A of our 2013 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

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

- *Crude oil and refined products*

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

- *Natural gas*

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

- *NGL*

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

See Note 10 to our condensed consolidated financial statements for further discussion regarding our hedging strategies and objectives.

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

The fair value of our commodity derivatives and the change in fair value as of June 30, 2014 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil and related products	$ 8	$ 20	$ (12)
Natural gas	4	$ 10	$ (10)
NGL and other	8	$ (45)	$ 45
Total fair value	$ 20		

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

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time we use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. The majority of our variable rate debt at June 30, 2014, approximately $760 million, is subject to interest rate re-sets, which range from one day to two weeks. The average interest rate of approximately 0.3% is based upon rates in effect during the first six months ended June 30, 2014. The fair value of our interest rate derivatives is a liability of approximately $7 million as of June 30, 2014. A 10% increase in the forward LIBOR curve as of June 30, 2014 would result in an increase of approximately $17 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of June 30, 2014 would result in a decrease of approximately $17 million to the fair value of our interest rate derivatives. See Note 10 to our condensed consolidated financial statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives is an asset of approximately $6 million as of June 30, 2014. A 10% increase in the exchange rate (USD-to-CAD) would result in a decrease of approximately $27 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would result in an increase of approximately $27 million to the fair value of our foreign currency derivatives. See Note 10 to our condensed consolidated financial statements for a discussion of our currency exchange rate risk hedging.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our DCP. Our DCP is designed to ensure that information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the Exchange Act) is (i) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in internal control over financial reporting. Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under the caption Litigation in Note 11 to our condensed consolidated financial statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2013 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

	By:	PAA GP LLC, its general partner
	By:	PLAINS AAP, L.P., its sole member
	By:	PLAINS ALL AMERICAN GP LLC, its general partner
Date: August 8, 2014		
	By:	/s/ Greg L. Armstrong Greg L. Armstrong, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*
Date: August 8, 2014		
	By:	/s/ Al Swanson Al Swanson, *Executive Vice President and Chief Financial Officer (Principal Financial Officer)*
Date: August 8, 2014		
	By:	/s/ Chris Herbold Chris Herbold, *Vice President- Accounting and Chief Accounting Officer (Principal Accounting Officer)*

EXHIBIT INDEX

3.1	Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of May 17, 2012 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 23, 2012).
3.2	Amendment No. 1 dated October 1, 2012 to the Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed October 2, 2012).
3.3	Amendment No. 2 dated December 31, 2013 to the Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed December 31, 2013).
3.4	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.5	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to the Annual Report on Form 10-K for the year ended December 31, 2010).
3.6	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2010).
3.7	Amendment No. 3 dated June 30, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to the Annual Report on Form 10-K for the year ended December 31, 2013).
3.8	Amendment No. 4 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.8 to the Annual Report on Form 10-K for the year ended December 31, 2013).
3.9	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.10	Amendment No. 1 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2013).
3.11	Sixth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated October 21, 2013 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed October 25, 2013).
3.12	Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated October 21, 2013 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed October 25, 2013).
3.13	Amendment No. 1 dated December 31, 2013 to Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed December 31, 2013).
3.14	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.15	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).

3.16	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.3	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.4	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.5	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.6	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.7	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.8	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.9	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.10	Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 13, 2010).
4.11	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed January 11, 2011).
4.12	Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed March 26, 2012).

4.13	Twenty-First Supplemental Indenture (5.15% Senior Notes due 2042) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed March 26, 2012).
4.14	Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp., and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed December 12, 2012).
4.15	Twenty-Third Supplemental Indenture (4.30% Senior Notes due 2043) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp., and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed December 12, 2012).
4.16	Twenty-Fourth Supplemental Indenture (3.85% Senior Notes due 2023) dated August 15, 2013, by and among Plains All American Pipeline, L.P., PAA Finance Corp., and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 15, 2013).
4.17	Twenty-Fifth Supplemental Indenture (4.70% Senior Notes due 2044) dated April 23, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp., and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 29, 2014).
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

Filed herewith.

Furnished herewith.