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, 2013

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 website, 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. (Check one):

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, 2013, there were 342,735,916 Common Units outstanding.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
TABLE OF CONTENTS

Page

PART I. FINANCIAL INFORMATION
Item 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS: 3
Condensed Consolidated Balance Sheets: June 30, 2013 and December 31, 2012 3
Condensed Consolidated Statements of Operations: For the three and six months ended June 30, 2013 and 2012 4
Condensed Consolidated Statements of Comprehensive Income: For the three and six months ended June 30, 2013 and 2012 5
Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income: For the six months ended June 30, 2013 5
Condensed Consolidated Statements of Cash Flows: For the six months ended June 30, 2013 and 2012 6
Condensed Consolidated Statement of Partners' Capital: For the six months ended June 30, 2013 7
Notes to Condensed Consolidated Financial Statements: 8
1. Organization and Basis of Presentation 8
2. Recent Accounting Pronouncements 9
3. Accounts Receivable 9
4. Acquisitions and Dispositions 10
5. Inventory, Linefill and Base Gas and Long-term Inventory 10
6. Goodwill 11
7. Debt 11
8. Net Income Per Limited Partner Unit 12
9. Partners' Capital and Distributions 14
10. Equity Compensation Plans 15
11. Derivatives and Risk Management Activities 17
12. Commitments and Contingencies 25
13. Operating Segments 26
14. Related Party Transactions 28

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS 29
Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK 45
Item 4. CONTROLS AND PROCEDURES 46

PART II. OTHER INFORMATION
Item 1. LEGAL PROCEEDINGS 47
Item 1A. RISK FACTORS 47
Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS 47
Item 3. DEFAULTS UPON SENIOR SECURITIES 47
Item 4. MINE SAFETY DISCLOSURES 47
Item 5. OTHER INFORMATION 47
Item 6. EXHIBITS 47
SIGNATURES 48

PART I. FINANCIAL INFORMATION

Item 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except units)

	June 30, 2013	December 31, 2012
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 16	$ 24
Trade accounts receivable and other receivables, net	3,503	3,563
Inventory	892	1,209
Other current assets	430	351
Total current assets	4,841	5,147
PROPERTY AND EQUIPMENT	11,762	11,142
Accumulated depreciation	(1,581)	(1,499)
	10,181	9,643
OTHER ASSETS		
Goodwill	2,503	2,535
Linefill and base gas	707	707
Long-term inventory	207	274
Investments in unconsolidated entities	442	343
Other, net	543	586
Total assets	$ 19,424	$ 19,235
LIABILITIES AND PARTNERS' CAPITAL		

CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,734	$ 3,822
Short-term debt	902	1,086
Other current liabilities	288	275
Total current liabilities	4,924	5,183
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $14 and $15, respectively	6,011	6,010
Long-term debt under credit facilities and other	302	310
Other long-term liabilities and deferred credits	558	586
Total long-term liabilities	6,871	6,906
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS' CAPITAL		
Common unitholders (341,691,037 and 335,283,874 units outstanding, respectively)	6,828	6,388
General partner	270	249
Total partners' capital excluding noncontrolling interests	7,098	6,637
Noncontrolling interests	531	509
Total partners' capital	7,629	7,146
Total liabilities and partners' capital	$ 19,424	$ 19,235

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(unaudited)		(unaudited)	
REVENUES				
Supply and Logistics segment revenues	$ 9,933	$ 9,442	$ 20,157	$ 18,319
Transportation segment revenues	165	158	338	307
Facilities segment revenues	197	186	420	378
Total revenues	10,295	9,786	20,915	19,004
COSTS AND EXPENSES				
Purchases and related costs	9,387	8,830	18,825	17,332
Field operating costs	343	319	684	568
General and administrative expenses	91	89	196	182
Depreciation and amortization	91	86	173	146
Total costs and expenses	9,912	9,324	19,878	18,228
OPERATING INCOME	383	462	1,037	776
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	11	9	23	16
Interest expense (net of capitalized interest of $10, $10, $19 and $18, respectively)	(75)	(75)	(152)	(140)
Other income/(expense), net	(1)	—	(1)	2
INCOME BEFORE TAX	318	396	907	654
Current income tax expense	(8)	(6)	(53)	(23)
Deferred income tax expense	(10)	(4)	(17)	(7)
NET INCOME	300	386	837	624
Net income attributable to noncontrolling interests	(8)	(8)	(16)	(15)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 292	$ 378	$ 821	$ 609
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 197	$ 303	$ 631	$ 465
GENERAL PARTNER	$ 95	$ 75	$ 190	$ 144
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.58	$ 0.93	$ 1.85	$ 1.45
DILUTED NET INCOME PER LIMITED PARTNER	$ 0.57	$ 0.93	$ 1.84	$ 1.44

UNIT				
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	340	323	338	319
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	342	326	341	321

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

Table of Contents

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(unaudited)		(unaudited)	
Net income	$ 300	$ 386	$ 837	$ 624
Other comprehensive loss	(92)	(108)	(138)	(49)
Comprehensive income	208	278	699	575
Comprehensive income attributable to noncontrolling interests	(15)	(6)	(20)	(9)
Comprehensive income attributable to Plains	$ 193	$ 272	$ 679	$ 566

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF
CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(in millions)

	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.

Table of Contents

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 837	$ 624
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	173	146
Inventory valuation adjustments	—	121
Equity-indexed compensation expense	78	60
Gain on sales of linefill and base gas	(3)	(16)
Net cash paid for terminated interest rate and foreign currency hedging instruments	—	(23)
(Gain)/loss on foreign currency revaluation	(5)	12
Deferred income tax expense	17	7
Other	(1)	(3)
Changes in assets and liabilities, net of acquisitions	241	(580)
Net cash provided by operating activities	1,337	348
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(31)	(1,534)
Additions to property, equipment and other	(785)	(544)
Cash received for sales of linefill and base gas	14	49
Cash paid for purchases of linefill and base gas	(24)	(29)

Investment in unconsolidated entities	(112)	—
Proceeds from sales of assets	3	19
Other investing activities	3	1
Net cash used in investing activities	(932)	(2,038)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on PAA's revolving credit facility (Note 7)	(65)	168
Net borrowings/(repayments) on PAA's hedged inventory facility (Note 7)	(85)	140
Net borrowings/(repayments) on PNG's credit agreements (Note 7)	(36)	37
Proceeds from the issuance of senior notes	—	1,247
Net proceeds from the issuance of common units (Note 9)	331	535
Issuance of PNG common units	30	—
Short-term borrowings related to cash overdraft	—	48
Distributions paid to common unitholders (Note 9)	(384)	(328)
Distributions paid to general partner (Note 9)	(175)	(135)
Distributions paid to noncontrolling interests	(24)	(24)
Other financing activities	(2)	(10)
Net cash provided by/(used in) financing activities	(410)	1,678
Effect of translation adjustment on cash	(3)	(2)
Net decrease in cash and cash equivalents	(8)	(14)
Cash and cash equivalents, beginning of period	24	26
Cash and cash equivalents, end of period	$ 16	$ 12
Cash paid for:		
Interest, net of amounts capitalized	$ 146	$ 129
Income taxes, net of amounts refunded	$ 18	$ 48

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(in millions)

	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	0.8	4	—	4	—	4
Units tendered by employees to satisfy tax withholding obligations	(0.3)	(15)	—	(15)	—	(15)
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.

Table of Contents

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

Note 1—Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 1998. 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. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a

Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. References to our "general partner," as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC.

We engage in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the processing, transportation, fractionation, storage and marketing of natural gas liquids ("NGL"). The term NGL includes ethane and natural gasoline products as well as propane and butane, products which are also commonly referred to as liquefied petroleum gas ("LPG"). When used in this document, NGL refers to all NGL products including LPG. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also own and operate natural gas storage facilities. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 13 for further discussion of our operating segments.

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
CME	=	Chicago Mercantile Exchange
DERs	=	Distribution equivalent rights
EBITDA	=	Earnings before interest, taxes, depreciation and amortization
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	IntercontinentalExchange
LIBOR	=	London Interbank Offered Rate
LLS	=	Light Louisiana Sweet
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
NPNS	=	Normal purchases and normal sales
NYMEX	=	New York Mercantile Exchange
NYSE	=	New York Stock Exchange
PLA	=	Pipeline loss allowance
PNG	=	PAA Natural Gas Storage, L.P.
SEC	=	Securities and Exchange Commission
USD	=	United States dollar
WTI	=	West Texas Intermediate
WTS	=	West Texas Sour

Table of Contents

Basis of Consolidation and Presentation

The accompanying unaudited condensed consolidated interim financial statements and notes thereto should be read in conjunction with our 2012 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, 2012 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, 2013 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 2012 Annual Report on Form 10-K, no new accounting pronouncements have become effective or have been issued during the six months ended June 30, 2013 that are of significance or potential significance to us.

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 becomes effective beginning after December 15, 2013. We will adopt this guidance on January 1, 2014. Our adoption is not expected to have a material impact on our financial position, results of operations or cash flows.

In February 2013, the FASB issued guidance requiring an entity to present either in a single note or parenthetically on the face of the financial statements (i) the amount of significant items reclassified from each component of AOCI and (ii) the income statement line items affected by the reclassification. This guidance became effective for interim and annual periods beginning after December 15, 2012. We adopted this guidance during the first quarter of 2013. During the six months ended June 30, 2013 and 2012, all reclassifications out of AOCI were related to derivative instruments. Other than requiring additional disclosure, which is included in Note 11, our adoption did not have an impact on our financial position, results of operations or cash flows.

In July 2012, the FASB issued guidance intended to simplify the impairment test for indefinite-lived intangible assets other than goodwill by giving entities the option to first assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. The results of the qualitative assessment would be used as a basis in determining whether it is necessary to perform the two-step quantitative impairment testing. An entity can choose to perform the qualitative assessment on none, some or all of its indefinite-lived intangible assets, or may bypass the qualitative assessment and proceed directly to the quantitative impairment test. This guidance is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted in certain circumstances. We adopted this guidance on January 1, 2013. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In December 2011, the FASB issued guidance requiring disclosures of both gross and net information about recognized financial instruments and derivative instruments that are either (i) offset in accordance with the specified sections of GAAP or (ii) subject to an enforceable master netting arrangement or similar agreement. In January 2013, the FASB amended and clarified the scope of these disclosures to include only (i) derivative instruments, (ii) repurchase agreements and reverse repurchase agreements and (iii) securities lending transactions. This guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. We adopted this guidance on January 1, 2013. Other than requiring additional disclosure, which is included in Note 11, our adoption did not have an 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 crude oil, NGL, natural gas and refined products terminalling and storage services. 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.

Table of Contents

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 standby letters of credit, parental guarantees or advance cash payments. At June 30, 2013 and December 31, 2012, we had received approximately $152 million and $173 million, respectively, of advance cash payments from third parties to mitigate credit risk. Furthermore, at June 30, 2013 and December 31, 2012, we had received approximately $448 million and $343 million, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. In addition, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables against each other) that cover a significant portion of our transactions and also serve to mitigate credit risk.

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, 2013 and December 31, 2012, 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 $4 million at both June 30, 2013 and December 31, 2012. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Note 4—Dispositions

In February 2013, we signed a definitive agreement to sell certain refined products pipeline systems and related assets included in our Transportation segment. At June 30, 2013 and December 31, 2012, these assets were classified as held for sale on our condensed consolidated balance sheets (in "Other current assets"). A portion of the transaction closed on July 1, 2013, and closing of the balance is subject to the satisfaction of customary closing conditions.

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

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

	June 30, 2013				December 31, 2012			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [1]
Inventory								
Crude oil	5,484	barrels	$ 471	$ 85.89	9,492	barrels	$ 737	$ 77.64
NGL	8,366	barrels	316	$ 37.77	9,472	barrels	388	$ 40.96
Natural gas	23,058	Mcf	78	$ 3.38	20,374	Mcf	60	$ 2.94
Other	N/A		27	N/A	N/A		24	N/A
Inventory subtotal			892				1,209	
Linefill and base gas								
Crude oil	10,026	barrels	585	$ 58.35	9,919	barrels	583	$ 58.78
NGL	1,358	barrels	64	$ 47.13	1,400	barrels	70	$ 50.00
Natural gas	16,965	Mcf	58	$ 3.42	15,755	Mcf	54	$ 3.43
Linefill and base gas subtotal			707				707	
Long-term inventory								
Crude oil	2,038	barrels	157	$ 77.04	1,962	barrels	149	$ 75.94
NGL	1,162	barrels	50	$ 43.03	3,238	barrels	125	$ 38.60
Long-term inventory subtotal			207				274	
Total			$ 1,806				$ 2,190	

(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. During the second quarter of 2012, we recorded a non-cash charge of approximately $121 million related to the writedown of our crude oil and NGL inventory due to declines in prices during the period. The recognition of this adjustment, which is a component of "Purchases and related costs" in our accompanying condensed consolidated statement of operations, was substantially offset by the recognition of unrealized gains on derivative instruments being utilized to hedge the future sales of our crude oil and NGL inventory. Substantially all of such unrealized gains were recorded to "Supply and Logistics segment revenues" on our condensed consolidated statement of operations. See Note 11 for discussion of our derivative and risk management activities. We did not recognize any writedowns of inventory during 2013.

Note 6 — 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, 2012	$ 897	$ 1,171	$ 467	$ 2,535
2013 Goodwill Related Activity:				
Foreign currency translation adjustments	(16)	(7)	(4)	(27)
Purchase price accounting adjustments and other (1)	(5)	—	—	(5)
Balance at June 30, 2013	$ 876	$ 1,164	$ 463	$ 2,503

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

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

Note 7—Debt

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

	June 30, 2013	December 31, 2012
SHORT-TERM DEBT		
Credit Facilities :		
PAA senior secured hedged inventory facility, bearing a weighted-average interest rate of 1.3% and 1.6% at June 30, 2013 and December 31, 2012, respectively	$ 575	$ 665
PAA senior unsecured revolving credit facility, bearing a weighted-average interest rate of 3.2% and 2.4% at June 30, 2013 and December 31, 2012, respectively (1)	25	92
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.0% and 2.1% at June 30, 2013 and December 31, 2012, respectively (2)	49	77
5.63% senior notes due December 2013 (3)	250	250
Other	3	2
Total short-term debt	902	1,086
LONG-TERM DEBT		
Senior notes, net of unamortized discounts of $14 and $15 at June 30, 2013 and December 31, 2012, respectively	6,011	6,010
Credit Facilities and Other:		
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.0% and 2.1% at June 30, 2013 and December 31, 2012, respectively (2)	97	105
PNG GO Bond term loans, bearing a weighted-average interest rate of 1.5% at both June 30, 2013 and December 31, 2012	200	200
Other	5	5
Total long-term debt	6,313	6,320
Total debt (1) (2) (4)	$ 7,215	$ 7,406

(1) We classify as short-term certain borrowings under our PAA senior unsecured revolving credit facility. 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) PNG classifies as short-term debt any borrowings under the PNG senior unsecured revolving credit facility that have been designated as working capital borrowings and must be repaid within one year. Such borrowings are primarily related to a portion of PNG's hedged natural gas inventory.

(3) Our $250 million 5.63% senior notes will mature in December 2013 and are thus classified as short-term at June 30, 2013 and December 31, 2012.

(4) Our fixed-rate senior notes (including current maturities) had a face value of approximately $6.3 billion at both June 30, 2013 and December 31, 2012. We estimated the aggregate fair value of these notes as of June 30, 2013 and December 31, 2012 to be approximately $6.8 billion and $7.3 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 approximates fair value as interest rates reflect current market rates. The fair value estimates for both our senior notes and credit facilities and agreements are based upon observable market data and are classified within level 2 of the fair value hierarchy.

Borrowings and Repayments under Credit Agreements

Total borrowings under our credit agreements for the six months ended June 30, 2013 and 2012 were approximately $7.561 billion and $4.856 billion, respectively. Total repayments under our credit agreements were approximately $7.747 billion and $4.511 billion for the six months ended June 30, 2013 and 2012, respectively.

Letters of Credit

In connection with our supply and logistics activities and PNG's natural gas storage and commercial marketing activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. At June 30, 2013 and December 31, 2012, we had outstanding letters of credit of approximately $50 million and $24 million, respectively.

Note 8—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 2012 Annual Report on Form 10-K for a complete discussion of our LTIP awards including specific discussion regarding DERs.

Table of Contents

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, 2013 and 2012 (in millions, except per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Basic Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 292	$ 378	$ 821	$ 609
General partner's incentive distribution [1]	(91)	(69)	(177)	(134)
General partner 2% ownership [1]	(4)	(6)	(13)	(10)
Net income available to limited partners	197	303	631	465
Undistributed earnings allocated and distributions to participating securities [1]	(1)	(2)	(5)	(3)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 196	$ 301	$ 626	$ 462
Basic weighted average number of limited partner units outstanding	340	323	338	319
Basic net income per limited partner unit	$ 0.58	$ 0.93	$ 1.85	$ 1.45
Diluted Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 292	$ 378	$ 821	$ 609
General partner's incentive distribution [1]	(91)	(69)	(177)	(134)
General partner 2% ownership [1]	(4)	(6)	(13)	(10)
Net income available to limited partners	197	303	631	465
Undistributed earnings allocated and distributions to participating securities [1]	(1)	(1)	(3)	(2)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 196	$ 302	$ 628	$ 463

Basic weighted average number of limited partner units outstanding	340	323	338	319
Effect of dilutive securities: Weighted average LTIP units	2	3	3	2
Diluted weighted average number of limited partner units outstanding	342	326	341	321
Diluted net income per limited partner unit	$ 0.57	$ 0.93	$ 1.84	$ 1.44

---

(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.

The terms of our partnership agreement limit the general partner's incentive distribution to the amount 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,	
	2013	2012	2013	2012
Basic net income per limited partner unit impact	$ —	$ (0.19)	$ (0.33)	$ (0.18)
Diluted net income per limited partner unit impact	$ —	$ (0.20)	$ (0.33)	$ (0.18)

Table of Contents

Note 9—Partners' Capital and Distributions

PAA Distributions

The following table details the distributions paid during or pertaining to the first six months of 2013, net of reductions to the general partner's incentive distributions (in millions, except per unit amounts):

		Distributions Paid				Distributions per limited partner unit
		Common Units	General Partner		Total	
Date Declared	Date Paid or To Be Paid		Incentive	2%		
July 8, 2013	August 14, 2013 (1)	$ 201	$ 91	$ 4	$ 296	$ 0.5875
April 8, 2013	May 15, 2013	$ 195	$ 86	$ 4	$ 285	$ 0.5750
January 7, 2013	February 14, 2013	$ 189	$ 81	$ 4	$ 274	$ 0.5625

---

(1) Payable to unitholders of record at the close of business on August 2, 2013, for the period April 1, 2013 through June 30, 2013.

PAA Continuous Offering Programs

On September 13, 2012, we entered into an equity distribution agreement with respect to the offer and sale, through our sales agents, of common units representing limited partner interests having an aggregate offering price of up to $500 million. The final sales under this equity distribution agreement occurred during May 2013. During the first six months of 2013, we issued an aggregate of approximately 5.1 million common units under this agreement, generating net proceeds of approximately $283 million, including our general partner's proportionate capital contribution, net of approximately $3 million of commissions to our sales agents. The net proceeds from sales were used for general partnership purposes.

On May 28, 2013, we entered into an additional equity distribution agreement with several financial institutions pursuant to which we may offer and sell, through our sales agents, common units representing limited partner interests having an aggregate offering price of up to $750 million. Sales of such common units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by our sales agent and us. Under the terms of the agreement, we have the option to sell common units to any of our sales agents as principal for its own account at a price to be agreed upon at the time of the sale. For any such sales, we will enter into a separate terms agreement with the sales agent.

Through June 30, 2013, we issued an aggregate of approximately 0.8 million common units under the May 2013 agreement, generating net proceeds of approximately $48 million, including our general partner's proportionate capital contribution, net of less than $1 million of commissions to our sales agents. The net proceeds from sales were used for general partnership purposes.

LTIP Vesting

In connection with the settlement of vested LTIP awards (both liability-classified and equity-classified), we issued approximately 0.5 million common units during the first six months of 2013, net of units tendered by employees for tax withholding obligations.

Noncontrolling Interests in Subsidiaries

As of June 30, 2013, noncontrolling interests in subsidiaries consisted of (i) an approximate 37% interest in PNG and (ii) a 25% interest in SLC Pipeline LLC.

PNG Continuous Offering Program

On March 18, 2013, PNG entered into an equity distribution agreement with a financial institution pursuant to which PNG may offer and sell, through its sales agent, common units representing limited partner interests having an aggregate offering price of up to $75 million. During the first six months of 2013, PNG issued an aggregate of approximately 1.4 million common units under this agreement, generating net proceeds of approximately $30 million, excluding our proportionate capital contribution for our general partner interest.

As a result of PNG's common unit issuances under its continuous offering program, we recorded an increase in noncontrolling interest of approximately $24 million and an increase to our partners' capital of approximately $6 million. The increases result from the portion of the proceeds attributable to the respective ownership interests in PNG, adjusted for the impact of the dilution of our ownership interest resulting from the issuances.

The following table sets forth the impact upon net income attributable to Plains giving effect to the changes in our ownership interest in PNG, which is recognized in partners' capital (in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Net income attributable to Plains	$ 292	$ 378	$ 821	$ 609
Transfers to the noncontrolling interests:				
Increase in capital from sale of PNG units	6	—	6	—
Change from net income attributable to Plains and net transfers to the noncontrolling interests	$ 298	$ 378	$ 827	$ 609

Noncontrolling Interests Rollforward

The following table reflects the changes in the noncontrolling interests in partners' capital (in millions):

	Six Months Ended June 30,	
	2013	2012
Beginning balance	$ 509	$ 524
Net income attributable to noncontrolling interests	16	15
Distributions to noncontrolling interests	(24)	(24)
Equity-indexed compensation expense	2	1
Other comprehensive income/(loss):		
Reclassification adjustments	6	(7)
Net deferred gain/(loss) on cash flow hedges	(2)	1
Issuance of PNG common units	24	—
Ending balance	$ 531	$ 510

Note 10—Equity-Indexed Compensation Plans

We refer to the PAA and PNG LTIP Plans, Special PAA Awards, PNG Transaction Grants and Class B Units of Plains AAP, L.P. 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 2012 Annual Report on Form 10-K.

Class B Units of Plains AAP, L.P. The following table contains a summary of Class B Units of Plains AAP, L.P.:

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value of Outstanding Class B Units (1) (in millions)
Balance at December 31, 2012	17,875	182,125	130,250	$ 44
Granted	(4,500)	4,500	—	7
Earned	N/A	N/A	26,000	N/A
Balance at June 30, 2013	13,375	186,625	156,250	$ 51

(1) Of the grant date fair value, approximately $2 million was recognized as expense during the six months ended June 30, 2013.

Special PAA Awards. In February 2013, we granted 143,000 Special PAA Awards to certain members of PNG's management. These awards are denominated in PAA common units and will vest 50% on PAA's August 2018 distribution date and 50% on PAA's August 2019 distribution date provided that PNG's annualized distribution averages at least $1.48 and $1.43 per unit, respectively, for the twelve months prior to each vesting date. DERs associated with these awards will vest on the date that we pay an annualized distribution of $2.40 per unit, provided that PNG's quarterly distribution remains at least $1.43 (annualized) per unit. Any unvested Special PAA Awards that remain outstanding on December 31, 2020 will be forfeited. These awards were granted in conjunction with the cancellation of the Class B Units of PNGS GP LLC, which were terminated in February 2013.

PAA and PNG LTIP Awards. Our equity compensation activity for LTIP awards denominated in PAA and PNG units is summarized in the following table (units in millions):

	PAA Units (1) (2) (3)		PNG Units (4) (5)	
	Units	Weighted Average Grant Date Fair Value per Unit	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2012	6.0	$ 25.55	0.9	$ 17.49
Granted	4.1	$ 47.57	0.4	$ 17.34
Vested	(1.8)	$ 24.77	—	$ 14.77
Cancelled or forfeited	(0.2)	$ 35.70	—	$ 14.40
Outstanding at June 30, 2013	8.1	$ 36.66	1.3	$ 17.57

(1) Amounts do not include Class B Units of Plains AAP, L.P.

(2) Amounts include Special PAA Awards.

(3) Approximately 0.5 million common units were issued, net of approximately 0.3 million units withheld for taxes, for PAA units that vested during the six months ended June 30, 2013. The remaining 1.0 million PAA units that vested were settled in cash.

(4) Amounts include PNG Transaction Grants.

(5) Less than 0.1 million PNG common units vested and less than 0.1 million common units were forfeited during the six months ended June 30, 2013.

In February 2013, we granted 2.4 million equity-classified phantom unit awards and 1.5 million liability-classified phantom unit awards under our PAA LTIPs. Substantially all of the equity-classified awards vest as follows: (i) one-third will vest upon the later of the August 2016 distribution date and the date we pay an annualized quarterly distribution of at least $2.35 per common unit, (ii) one-third will vest upon the later of the August 2017 distribution date and the date we pay an annualized quarterly distribution of at least $2.50 per common unit, and (iii) one-third will vest upon the later of the August 2018 distribution date and the date we pay an annualized quarterly distribution of at least $2.65 per unit. Any of these equity-classified awards and associated DERs that have not vested as of the August 2019 distribution date will be forfeited. Substantially all of the liability-classified awards are expected to vest on dates ranging from the August 2015 distribution date to the August 2018 distribution date and vest dependent on PAA paying annualized quarterly distributions ranging from $2.30 per common unit to $2.65 per common unit. Certain of these phantom unit awards include DERs that will vest in one-third increments upon achieving distributions of $2.35, $2.50 and $2.65 per common unit, without regard to the minimum service period.

Other 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,	
	2013	2012	2013	2012
Equity-indexed compensation expense	$ 27	$ 20	$ 78	$ 60
LTIP unit-settled vestings (1)	$ 46	$ 33	$ 46	$ 58
LTIP cash-settled vestings	$ 60	$ 29	$ 60	$ 65
DER cash payments	$ 2	$ 2	$ 4	$ 4

(1) For each of the three and six months ended June 30, 2012, approximately $1 million relates to unit-settled vestings that were settled with PNG common units.

Note 11—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 contain certain commodity price-related risks that we manage in various ways, including 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, 2013, net derivative positions related to these activities included:

- An average of 332,800 barrels per day net long position (total of 10.3 million barrels) associated with our crude oil purchases, which was unwound ratably during July 2013 to match monthly average pricing.

- A net short spread position averaging approximately 27,800 barrels per day (total of 11.0 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through September 2014. 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 13,000 barrels per day (total of 2.0 million barrels) of WTS/WTI crude oil basis futures through December 2013, which hedge anticipated purchases and sales of crude oil. These derivatives are grade spreads between two different grades of crude oil. Our use of these derivatives does not expose us to outright price risk.

- An average of 3,400 barrels per day (total of 0.5 million barrels) of LLS/WTI crude oil basis futures through December 2013, which hedge anticipated purchases and sales of crude oil. These derivatives are grade spreads between two different grades of crude oil. Our use of these derivatives does not expose us to outright price risk.

- An average of 2,300 barrels per day (total of 1.4 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are priced as a percentage of WTI through March 2015.

- A net long position of approximately 1.9 Bcf through April 2016 related to anticipated base gas requirements.

- A short position of approximately 22.9 Bcf through December 2013 related to anticipated sales of owned natural gas inventory.

Storage Capacity Utilization — We own a significant amount of crude oil, NGL and refined products storage capacity other than that used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk in a backwardated market structure. As of June 30, 2013, we used derivatives to manage the risk of not utilizing approximately 2.4 million barrels per month of storage capacity through December 2013. These positions involve no outright price exposure, but instead enable us to profitably use the capacity to store hedged crude oil.

Inventory Storage — From time to time, we elect to purchase and store crude oil, NGL and refined products inventory in conjunction with our supply and logistics activities. When we purchase and store inventory, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of June 30, 2013, we had derivatives totaling approximately 6.6 million barrels hedging our 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, 2013, our PLA hedges included (i) a net short position for an average of approximately 1,700 barrels per day (total of 1.6 million barrels) through December 2015, (ii) a long put option position of approximately 0.1 million barrels through December 2013 and (iii) a long call option position of approximately 0.4 million barrels through December 2015.

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 purchase of natural gas and the subsequent sale of the individual specification products. As of June 30, 2013, we had a long natural gas position of approximately 13.7 Bcf through March 2015, a short propane position of approximately 2.4 million barrels through March 2015, a short butane position of approximately 0.7 million barrels through March 2015 and a short WTI position of approximately 0.2 million barrels through March 2015. 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 2015.

All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. We have determined that substantially all of our physical purchase and sale agreements qualify for the NPNS exclusion. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the NPNS 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, 2013, AOCI includes deferred losses of approximately $90 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, 2013 (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	5 forward starting swaps (30-year)	$ 125	6/16/2014	3.39%	Cash flow hedge
Anticipated debt offering	10 forward starting swaps (30-year)	$ 250	6/15/2015	3.60%	Cash flow hedge

During June 2011 and August 2011, PNG entered into three interest rate swaps to fix the interest rate on a portion of PNG's outstanding debt. The following table summarizes the terms of these swaps (notional amount in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Termination Dates	Average Fixed Rate	Accounting Treatment
Floating interest rate payments associated with PNG outstanding	3 floating-to-fixed swaps	$ 100	6/6/2014 8/3/2014	0.95%	Cash flow hedge

debt

Table of Contents

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, 2013, AOCI includes net deferred gains of approximately $3 million that relate to foreign currency derivatives that were designated for hedge accounting.

As of June 30, 2013, our outstanding foreign currency derivatives include derivatives we use to (i) hedge CAD-denominated interest payments on CAD-denominated intercompany notes, (ii) hedge currency exchange risk associated with USD-denominated commodity purchases and sales in Canada and (iii) 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, 2013 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2013	$ 214	$ 224	$1.00 - $1.05
	2014	42	44	$1.00 - $1.06
	2015	9	9	$1.00 - $1.07
		$ 265	$ 277	$1.00 - $1.05
Forward exchange contracts that exchange USD for CAD:				
	2013	$ 209	$ 216	$1.00 - $1.03
	2014	42	43	$1.00 - $1.03
	2015	9	9	$1.00 - $1.06
		$ 260	$ 268	$1.00 - $1.03
Net position by currency:				
	2013	$ 5	$ 8	
	2014	—	1	
	2015	—	—	
		$ 5	$ 9	

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. For our interest rate swaps that qualify as fair value hedges, changes in the fair value of the derivatives are recognized in earnings each period. Additionally, the change in fair value of the hedged item, attributable to the hedged risk, is recognized as a basis adjustment to the hedged item and is also 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.

Table of Contents

A summary of the impact of our derivative activities recognized in earnings for the three and six months ended June 30, 2013 and 2012 is as follows (in millions):

	Three Months Ended June 30, 2013				Three Months Ended June 30, 2012			
	Derivatives in Hedging Relationships				Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(loss) reclassified from AOCI into income (1)	Other gain/(loss) recognized in income	Derivatives Not Designated as a Hedge (2)	Total	Gain/(loss) reclassified from AOCI into income (1)	Other gain/(loss) recognized in income	Derivatives Not Designated as a Hedge (2)	Total
Commodity Derivatives								
Supply and Logistics segment revenues	$ 21	$ —	$ 21	$ 42	$ (97)	$ 1	$ 199	$ 103
Facilities segment revenues	(9)	—	—	(9)	1	—	—	1
Purchases and related costs	—	—	—	—	37	—	(1)	36

Field operating costs	—	—	4	4	—	—	(4)	(4)
Interest Rate Derivatives								
Interest expense	(2)	—	—	(2)	(1)	1	—	—
Foreign Currency Derivatives								
Supply and Logistics segment revenues	—	—	—	—	—	—	(1)	(1)
Other income/(expense), net	1	—	—	1	1	—	—	1
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ 11**	**$ —**	**$ 25**	**$ 36**	**$ (59)**	**$ 2**	**$ 193**	**$ 136**

	Six Months Ended June 30, 2013				Six Months Ended June 30, 2012			
	Derivatives in Hedging Relationships				Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(loss) reclassified from AOCI into income [1]	Other gain/(loss) recognized in income	Derivatives Not Designated as a Hedge [2]	Total	Gain/(loss) reclassified from AOCI into income [1]	Other gain/(loss) recognized in income	Derivatives Not Designated as a Hedge [2]	Total
Commodity Derivatives								
Supply and Logistics segment revenues	$ 29	$ —	$ 59	$ 88	$ (59)	$ (2)	$ 161	$ 100
Facilities segment revenues	(12)	—	—	(12)	13	—	—	13
Purchases and related costs	—	—	—	—	41	—	—	41
Field operating costs	—	—	5	5	—	—	(2)	(2)
Interest Rate Derivatives								
Interest expense	(3)	—	—	(3)	(3)	2	—	(1)
Foreign Currency Derivatives								
Other income/(expense), net	2	—	—	2	2	—	—	2
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ 16**	**$ —**	**$ 64**	**$ 80**	**$ (6)**	**$ —**	**$ 159**	**$ 153**

Table of Contents

(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. All of our hedged transactions were deemed probable of occurring during the three and six months ended June 30, 2012.

(2) Includes realized and unrealized gains and losses for derivatives that did not qualify or were not designated for hedge accounting during the period.

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of June 30, 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	$ 40	Other current assets	$ (14)
	Other long-term assets	9	Other long-term assets	(4)
Interest rate derivatives	Other current assets	8	Other current assets	(3)
	Other long-term assets	10	Other long-term assets	(1)
			Other current liabilities	(1)
			Other long-term liabilities	(1)
Total derivatives designated as hedging instruments		$ 67		$ (24)

Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 131	Other current assets	$ (92)
	Other long-term assets	9	Other long-term assets	(2)
	Other current liabilities	1	Other current liabilities	(4)
	Other long-term liabilities	1	Other long-term liabilities	(2)
Foreign currency derivatives			Other current liabilities	(5)
Total derivatives not designated as hedging instruments		$ 142		$ (105)
Total derivatives		$ 209		$ (129)

Table of Contents

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of December 31, 2012 (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	$ 45	Other current assets	$ (23)
	Other long-term assets	11	Other long-term assets	(1)
Interest rate derivatives			Other long-term liabilities	(38)
Total derivatives designated as hedging instruments		$ 56		$ (62)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 128	Other current assets	$ (115)
	Other long-term assets	1	Other long-term assets	(3)
	Other current liabilities	4	Other current liabilities	(7)
	Other long-term liabilities	2	Other long-term liabilities	(2)
Total derivatives not designated as hedging instruments		$ 135		$ (127)
Total derivatives		$ 191		$ (189)

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.

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, 2013, we had a net broker receivable of approximately $70 million (consisting of initial margin of $78 million reduced by $8 million of variation margin that had been returned to us). As of December 31, 2012, we had a net broker receivable of approximately $41 million (consisting of initial margin of $69 million reduced by $28 million of variation margin that had been returned to 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, 2013 and December 31, 2012 (in millions):

Table of Contents

	June 30, 2013		December 31, 2012	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 209	$ (129)	$ 191	$ (189)
Netting adjustment	(118)	118	(148)	148
Cash collateral paid/(received)	70	—	41	—
Net position - asset/(liability)	$ 161	$ (11)	$ 84	$ (41)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 140	$ —	$ 76	$ —

Other long-term assets	21	—	8	—
Other current liabilities	—	(9)	—	(3)
Other long-term liabilities	—	(2)	—	(38)
	$ 161	$ (11)	$ 84	$ (41)

As of June 30, 2013, there was a net loss of approximately $74 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, (ii) interest expense accruals associated with underlying debt instruments or (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD-denominated intercompany balances. Of the total net loss deferred in AOCI at June 30, 2013, we expect to reclassify a net gain of approximately $14 million to earnings in the next twelve months. Of the remaining deferred loss in AOCI, a net gain of approximately $1 million is expected to be reclassified to earnings prior to 2016 with the remaining deferred loss of approximately $89 million being reclassified to earnings through 2045. A portion of these amounts are based on market prices as of June 30, 2013; 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 during the three and six months ended June 30, 2013 and 2012 are as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Commodity derivatives, net	$ 3	$ (25)	$ 11	$ —
Interest rate derivatives, net	32	(79)	51	(28)
Total	$ 35	$ (104)	$ 62	$ (28)

At June 30, 2013 and December 31, 2012, 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.

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, 2013 and December 31, 2012 (in millions):

	Fair Value as of June 30, 2013				Fair Value as of December 31, 2012			
Recurring Fair Value Measures [(1)]	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$ 27	$ 42	$ 4	$ 73	$ 1	$ 35	$ 4	$ 40
Interest rate derivatives	—	12	—	12	—	(38)	—	(38)
Foreign currency derivatives	—	(5)	—	(5)	—	—	—	—
Total	$ 27	$ 49	$ 4	$ 80	$ 1	$ (3)	$ 4	$ 2

(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. 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 over-the-counter commodity derivatives that are traded in markets that are active but not sufficiently active to warrant level 2 classification in our judgment and certain physical commodity contracts. The fair value of our level 3 over-the-counter commodity derivatives is based on broker price quotations. 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 (decrease) in these forward prices would result in a proportionately lower (higher) fair value measurement.

Rollforward of Level 3 Net Asset/(Liability)

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

	Three Months Ended June 30,	Six Months Ended June 30,

	2013	2012	2013	2012
Beginning Balance	$ 1	$ 2	$ 4	$ 12
Unrealized gains/(losses):				
Included in earnings [(1)]	1	12	1	8
Included in other comprehensive income	—	—	—	3
Settlements	—	(2)	(3)	(14)
Derivatives entered into during the period	2	19	2	22
Transfers out of level 3	—	5	—	5
Ending Balance	$ 4	$ 36	$ 4	$ 36
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ 3	$ 31	$ 3	$ 33

(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.

During the second quarter of 2012, we transferred commodity derivatives with an aggregate fair value of a $5 million loss from level 3 to level 2. These derivatives consist of NGL derivatives that are cleared through the CME Clearport platform. This transfer resulted from additional analysis regarding the CME's pricing methodology. Our policy is to recognize transfers between levels as of the beginning of the reporting period in which the transfer occurred.

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and will therefore be offset by gains or losses on the underlying transactions.

Table of Contents

Note 12—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 and including the general and environmental legal proceedings described below, will have a material adverse effect on our financial condition, results of operations or cash flows.

Pemex Exploración y Producción v. Big Star Gathering Ltd L.L.P. et al. 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. At a hearing held on October 20, 2011, the Court ruled that Texas law (not Mexican law) governs the actions. In February 2013, the Court granted Plains Marketing, L.P.'s motion to be dismissed from the April 2012 lawsuit and Plains Marketing, L.P. filed a motion for summary judgment in the May 2011 lawsuit.

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 and storage operations. These releases can result from unpredictable man-made or natural forces and may reach "navigable waters" 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, 2013, our estimated undiscounted reserve for environmental liabilities totaled approximately $110 million, of which approximately $17 million was classified as short-term and approximately $93 million was classified as long-term. At December 31, 2012, our reserve for environmental liabilities totaled approximately $96 million, of which approximately $13 million was classified as short-term and approximately $83 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, 2013 and December 31, 2012, we had recorded receivables totaling approximately $15 million and $42 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 to five years. 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. On April 29, 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, 2013, we spent approximately $70 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of June 30, 2013, we did not have any material outstanding liabilities or insurance receivables relating to this release. On February 26, 2013, the Alberta Energy Regulator (formerly known as the Energy Resources Conservation Board of Alberta) ("AER") issued a report detailing four enforcement actions against Plains Midstream Canada ULC ("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 is in the process of taking 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 the taking of 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 civil charges under the Environmental Protection and Enhancement Act against PMC relating to the release. To date, PMC has not been assessed any fines or penalties related to this release; however, such fines or penalties may be assessed in the future and are not reasonably estimable at this time.

Rangeland Pipeline Release. On June 7, 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 was completed by September 30, 2012 and interim closure was received from the applicable regulatory agencies. Ongoing monitoring will continue into 2013, and a long-term monitoring plan, if required, will be developed and implemented in accordance with regulatory requirements. Through June 30, 2013, we spent approximately $45 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of June 30, 2013, we did not have any material outstanding liabilities or insurance receivables relating to this release. This release is currently under investigation by the AER, which is also performing a full audit of PMC's operations. Although the AER's final investigation is not complete, on July 4, 2013, the AER issued a report detailing 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. The AER also issued an order under Section 22 of the Oil and Gas Conservation Act imposing additional regulatory requirements on PMC with respect to obtaining operating approvals under such Act during the pendency of the AER's audit. To date, no fines or penalties have been assessed against PMC with respect to this release; however, it is possible that fines or penalties may be assessed against PMC in the future and are not reasonably estimable at this time.

Bay Springs Pipeline Release. On February 5, 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, and we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was approximately $6 million, which has been recognized in "Field operating costs" on our condensed consolidated statement of operations.

Kemp River Pipeline Release. During May and June 2013, two separate events occurred on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the estimated release of approximately 1,250 barrels of condensate. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. We estimate that the aggregate clean-up and remediation costs associated with these releases will be approximately $15 million which we have accrued to "Field operating costs" on our condensed consolidated statement of operations.

Note 13—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. 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, 2013				
Revenues:				
External Customers	$ 165	$ 197	$ 9,933	$ 10,295
Intersegment [(1)]	200	151	1	352
Total revenues of reportable segments	$ 365	$ 348	$ 9,934	$ 10,647
Equity earnings in unconsolidated entities	$ 11	$ —	$ —	$ 11
Segment profit [(2) (3)]	$ 160	$ 149	$ 176	$ 485
Maintenance capital	$ 23	$ 11	$ 5	$ 39
Three Months Ended June 30, 2012				
Revenues:				
External Customers	$ 158	$ 186	$ 9,442	$ 9,786
Intersegment [(1)]	203	101	—	304
Total revenues of reportable segments	$ 361	$ 287	$ 9,442	$ 10,090
Equity earnings in unconsolidated entities	$ 9	$ —	$ —	$ 9
Segment profit [(2) (3)]	$ 169	$ 114	$ 274	$ 557
Maintenance capital	$ 27	$ 10	$ 3	$ 40

	Transportation	Facilities	Supply and Logistics	Total
Six Months Ended June 30, 2013				
Revenues:				

External Customers	$ 338	$ 420	$ 20,157	$ 20,915
Intersegment [(1)]	394	283	1	678
Total revenues of reportable segments	$ 732	$ 703	$ 20,158	$ 21,593
Equity earnings in unconsolidated entities	$ 23	$ —	$ —	$ 23
Segment profit [(2) (3)]	$ 323	$ 300	$ 610	$ 1,233
Maintenance capital	$ 55	$ 18	$ 9	$ 82
Six Months Ended June 30, 2012				
Revenues:				
External Customers	$ 307	$ 378	$ 18,319	$ 19,004
Intersegment [(1)]	371	145	—	516
Total revenues of reportable segments	$ 678	$ 523	$ 18,319	$ 19,520
Equity earnings in unconsolidated entities	$ 16	$ —	$ —	$ 16
Segment profit [(2) (3)]	$ 332	$ 204	$ 402	$ 938
Maintenance capital	$ 52	$ 17	$ 7	$ 76

(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market. For further discussion, see “Analysis of Operating Segments” under Item 7 of our 2012 Annual Report on Form 10-K.

(2) Supply and Logistics segment profit includes interest expense (related to hedged inventory) of approximately $5 million and $4 million for the three months ended June 30, 2013 and 2012, respectively, and approximately $10 million and $6 million for the six months ended June 30, 2013 and 2012, respectively.

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Segment profit	$ 485	$ 557	$ 1,233	$ 938
Depreciation and amortization	(91)	(86)	(173)	(146)
Interest expense	(75)	(75)	(152)	(140)
Other income/(expense), net	(1)	—	(1)	2
Income tax expense	(18)	(10)	(70)	(30)
Net income	300	386	837	624
Net income attributable to noncontrolling interests	(8)	(8)	(16)	(15)
Net income attributable to Plains	$ 292	$ 378	$ 821	$ 609

Note 14—Related Party Transactions

See Note 14 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Occidental Petroleum Corporation

As of June 30, 2013, a subsidiary of Occidental Petroleum Corporation (“Oxy”) owned approximately 35% of our general partner interest and had a representative on the board of directors of Plains All American GP LLC. During the three and six months ended June 30, 2013 and 2012, 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, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Revenues	$ 424	$ 597	$ 694	$ 1,051
Purchases and related costs	$ 214	$ 130	$ 375	$ 278

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, 2013	December 31, 2012
Trade accounts receivable and other receivables	$ 276	$ 231
Accounts payable	$ 192	$ 129

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 2012 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 engage in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as the processing, transportation, fractionation, storage and marketing of NGL. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P., we also own and operate natural gas storage facilities. 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 2013, net income attributable to Plains was approximately $821 million, or $1.84 per diluted limited partner unit, as compared to net income attributable to Plains of approximately $609 million, or $1.44 per diluted limited partner unit, recognized during the first six months of 2012. Major items impacting the favorable performance between periods include contributions from the BP NGL and USD Rail Terminal Acquisitions, which were completed in April 2012 and December 2012, respectively, and stronger unit margins in our Supply and Logistics segment.

The stronger unit margins in the Supply and Logistics segment were primarily due to contributions from our NGL marketing operations, which benefited from improved market conditions, as well as additional sales volumes related to the BP NGL Acquisition noted above. To a lesser extent, the stronger unit margins, which included the benefit from favorable location and quality differentials, are associated with the increased production from the development of North American crude oil and liquids-rich resource plays. However, infrastructure additions in many of these resource plays during the second quarter of 2013 began to relieve certain of the logistical challenges that had previously created opportunities for these favorable margins. As the midstream infrastructure in these producing regions continues to be developed, we believe a normalization of these margins will continue to occur as the logistical challenges are addressed.

Table of Contents

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, 2013	Six Months Ended June 30, 2012
Acquisition capital	$ 1	$ 1,656
Internal growth projects	830	511
Maintenance capital	82	76
Total	$ 913	$ 2,243

Internal Growth Projects

The following table summarizes our more notable projects in progress during 2013 and the forecasted expenditures for the year ending December 31, 2013 (in millions):

Projects	2013
Mississippian Lime Pipeline	$170

Rainbow II Pipeline	135
Yorktown Terminal Projects	100
Gulf Coast Pipeline	95
Eagle Ford Area Pipeline Projects	90
White Cliffs Expansion	90
Rail Terminal Projects [(1)]	80
Cactus Pipeline	75
Fort Saskatchewan Facility Expansions	75
Eagle Ford JV Project	70
St. James Terminal Projects	55
Western Oklahoma Extension	45
PAA Natural Gas Storage (Multiple Projects)	44
Spraberry Area Pipeline Projects	40
Gulf Coast Gas Processing Facility Enhancements	35
Cushing Terminal Projects	30
Shafter Expansion	25
Other Projects [(2)]	346
	$1,600
Potential Adjustments for Timing/Scope Refinement [(3)]	-$50 + $100
Total Projected Expansion Capital Expenditures	$1,550 - $1,700

(1) Includes projects located at or near Tampa, CO, Bakersfield, CA and Van Hook, ND.

(2) Primarily multiple, smaller projects comprised of pipeline connections, upgrades and truck stations, new tank construction and refurbishing, pipeline linefill purchases and carry-over of capital from prior year projects.

(3) 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.

Table of Contents

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 2012 Annual Report on Form 10-K for further discussion of how we evaluate segment performance.

The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP (in millions, except for per unit amounts):

	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
	2013	2012	$	%	2013	2012	$	%
Transportation segment profit	$ 160	$ 169	$ (9)	(5)%	$ 323	$ 332	$ (9)	(3)%
Facilities segment profit	149	114	35	31%	300	204	96	47%
Supply and Logistics segment profit	176	274	(98)	(36)%	610	402	208	52%
Total segment profit	485	557	(72)	(13)%	1,233	938	295	31%
Depreciation and amortization	(91)	(86)	(5)	(6)%	(173)	(146)	(27)	(18)%
Interest expense	(75)	(75)	—	—%	(152)	(140)	(12)	(9)%
Other income/(expense), net	(1)	—	(1)	N/A	(1)	2	(3)	(150)%
Income tax expense	(18)	(10)	(8)	(80)%	(70)	(30)	(40)	(133)%
Net income	300	386	(86)	(22)%	837	624	213	34%
Net income attributable to noncontrolling interests	(8)	(8)	—	—%	(16)	(15)	(1)	(7)%
Net income attributable to Plains	$ 292	$ 378	$ (86)	(23)%	$ 821	$ 609	$ 212	35%
Net income attributable to Plains:								
Basic net income per limited partner unit	$ 0.58	$ 0.93	$ (0.35)	(38)%	$ 1.85	$ 1.45	$ 0.40	28%
Diluted net income per limited partner unit	$ 0.57	$ 0.93	$ (0.36)	(39)%	$ 1.84	$ 1.44	$ 0.40	28%
Basic weighted average units outstanding	340	323	17	5%	338	319	19	6%
Diluted weighted average units outstanding	342	326	16	5%	341	321	20	6%

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 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 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.

Table of Contents

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,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
	2013	2012	$	%	2013	2012	$	%
Net income	$ 300	$ 386	$ (86)	(22)%	$ 837	$ 624	$ 213	34%
Add:								
Depreciation and amortization	91	86	(5)	(6)%	173	146	(27)	(18)%
Income tax expense	18	10	(8)	(80)%	70	30	(40)	(133)%
Interest expense	75	75	—	—%	152	140	(12)	(9)%
EBITDA	$ 484	$ 557	$ (73)	(13)%	$ 1,232	$ 940	$ 292	31%
Selected Items Impacting Comparability of EBITDA								
Gains/(losses) from derivative activities net of inventory valuation adjustments[(1)]	$ 26	$ 72	$ (46)	(64)%	$ 50	$ 13	$ 37	285%
Equity-indexed compensation expense [(2)]	(16)	(12)	(4)	(33)%	(39)	(38)	(1)	(3)%
Net gain/(loss) on foreign currency revaluation [(3)]	(4)	(16)	12	75%	4	(16)	20	125%
Significant acquisition-related expenses	—	(9)	9	100%	—	(13)	13	100%
Other [(4)]	—	—	—	—%	—	(1)	1	100%
Selected Items Impacting Comparability of EBITDA	$ 6	$ 35	$ (29)	(83)%	$ 15	$ (55)	$ 70	127%
EBITDA	$ 484	$ 557	$ (73)	(13)%	$ 1,232	$ 940	$ 292	31%
Selected Items Impacting Comparability of EBITDA	(6)	(35)	29	83%	(15)	55	(70)	(127)%
Adjusted EBITDA	$ 478	$ 522	$ (44)	(8)%	$ 1,217	$ 995	$ 222	22%
Adjusted EBITDA	$ 478	$ 522	$ (44)	(8)%	$ 1,217	$ 995	$ 222	22%
Interest expense	(75)	(75)	—	—%	(152)	(140)	(12)	(9)%
Maintenance capital	(39)	(40)	1	3%	(82)	(76)	(6)	(8)%
Current income tax expense	(8)	(6)	(2)	(33)%	(53)	(23)	(30)	(130)%
Equity earnings in unconsolidated entities, net of distributions	(1)	1	(2)	(200)%	(1)	—	(1)	N/A
Distributions to noncontrolling interests [(5)]	(13)	(12)	(1)	(8)%	(25)	(24)	(1)	(4)%
Implied DCF	$ 342	$ 390	$ (48)	(12)%	$ 904	$ 732	$ 172	23%

(1) Includes mark-to-market gains and losses resulting from 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, net of inventory valuation adjustments. See Note 11 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and risk management activities.

(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 compensation expense associated with these awards is shown as a selected item impacting comparability in the table above. The portion of compensation expense associated with awards that are certain to be settled in cash are not considered a selected item impacting

comparability. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for a comprehensive discussion regarding our equity compensation plans.

(3) During the three and six months ended June 30, 2013 and 2012, there were fluctuations in the value of the Canadian dollar to the U.S dollar, resulting in net 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 11 to our condensed consolidated financial statements for further discussion regarding our currency exchange rate risk hedging activities.

(4) Includes other immaterial selected items impacting comparability.

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

Table of Contents

Analysis of Operating Segments

Transportation Segment

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

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

Operating Results [1] (in millions, except per barrel amounts)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Revenues [1]								
Tariff activities	$ 310	$ 314	$ (4)	(1)%	$ 629	$ 591	$ 38	6%
Trucking	55	47	8	16%	103	87	16	18%
Total transportation revenues	365	361	4	1%	732	678	54	8%
Costs and Expenses [1]								
Trucking costs	(39)	(35)	(4)	(12)%	(74)	(63)	(11)	(18)%
Field operating costs (excluding equity- indexed compensation expense)	(138)	(128)	(10)	(8)%	(270)	(224)	(46)	(21)%
Equity-indexed compensation expense - operations [2]	(4)	(3)	(1)	(33)%	(13)	(10)	(3)	(30)%
Segment general and administrative expenses [3] (excluding equity-indexed compensation expense)	(26)	(28)	2	7%	(49)	(49)	—	—%
Equity-indexed compensation expense - general and administrative [2]	(9)	(7)	(2)	(29)%	(26)	(16)	(10)	(63)%
Equity earnings in unconsolidated entities	11	9	2	22%	23	16	7	44%
Segment profit	$ 160	$ 169	$ (9)	(5)%	$ 323	$ 332	$ (9)	(3)%
Maintenance capital	$ 23	$ 27	$ 4	15%	$ 55	$ 52	$ (3)	(6)%
Segment profit per barrel	$ 0.49	$ 0.52	$ (0.03)	(6)%	$ 0.49	$ 0.54	$ (0.05)	(9)%

Average Daily Volumes (in thousands of barrels per day) [4]	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Favorable/(Unfavorable) Variance Volumes	Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Variance Favorable/(Unfavorable) Volumes	Variance Favorable/(Unfavorable) %
Tariff activities								
Crude Oil Pipelines								
All American	38	31	7	23%	39	28	11	39%
Bakken Area Systems	130	135	(5)	(4)%	127	136	(9)	(7)%
Basin / Mesa	680	707	(27)	(4)%	702	675	27	4%
Capline	158	149	9	6%	157	136	21	15%
Eagle Ford Area Systems	74	15	59	393%	61	12	49	408%
Line 63 / Line 2000	108	130	(22)	(17)%	113	124	(11)	(9)%
Manito	46	57	(11)	(19)%	46	62	(16)	(26)%
Mid-Continent Area Systems	255	262	(7)	(3)%	261	242	19	8%
Permian Basin Area Systems	548	447	101	23%	513	451	62	14%
Rainbow	125	156	(31)	(20)%	124	149	(25)	(17)%
Rangeland	56	61	(5)	(8)%	62	62	—	—%
Salt Lake City Area Systems	131	157	(26)	(17)%	133	148	(15)	(10)%
South Saskatchewan	33	59	(26)	(44)%	46	60	(14)	(23)%
White Cliffs	21	17	4	24%	21	17	4	24%
Other	766	743	23	3%	763	735	28	4%
NGL Pipelines								
Co-Ed	51	64	(13)	(20)%	54	32	22	69%
Other	165	159	6	4%	186	79	107	135%

Refined Products Pipelines	110	118	(8)	(7)%	105	115	(10)	(9)%
Tariff activities total	3,495	3,467	28	1%	3,513	3,263	250	8%
Trucking	108	96	12	13%	109	102	7	7%
Transportation segment total	3,603	3,563	40	1%	3,622	3,365	257	8%

Table of Contents

(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.

(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 acquisitions represent total volumes (attributable to our interest) for the number of days we actually owned 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 tables above, our total Transportation segment revenues, net of trucking costs, and volumes remained relatively consistent for the three months ended June 30, 2013 compared to the three months ended June 30, 2012, while net revenues and volumes increased for the six months ended June 30, 2013 compared to the six months ended June 30, 2012. Although total volumes and revenues remained relatively consistent over the three-month comparative periods, we experienced volume and revenue variances among our individual pipelines and pipeline systems. The following factors contributed to the variances in revenues and volumes between the comparative periods and the variances among our individual pipelines and pipeline systems:

· North American Crude Oil Production and Related Expansion Projects — For the six-month comparative period, the favorable volume and revenue variances experienced were primarily due to increased producer drilling activities as well as the completion of certain of our expansion projects, most notably on our Basin, Mesa and White Cliffs pipelines and our Permian Basin, Mid-Continent and Eagle Ford Area Systems.

For the three-month comparative period, the favorable volume and revenue variances were primarily on our Permian Basin and Eagle Ford Area Systems and White Cliffs pipeline, while volumes and revenues on our Basin and Mesa pipelines were unfavorable compared to the second quarter of 2012. The Permian Basin Area Systems benefited from increased movements to new third-party pipelines connected to the Gulf Coast; however, these movements caused unfavorable volume and revenue variances on our Basin and Mesa pipelines.

We estimate that increased production combined with our phased-in expansion projects increased revenues by over $7 million and $18 million for the three and six month periods of 2013 over the comparable three and six month 2012 periods, respectively.

· Rate Changes — Revenues on our pipelines are impacted by various rate changes that occur during the period. These rate changes primarily include the upward indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate and Canadian pipelines or other negotiated rate changes. The upward indexing that was effective July 1, 2012 had a favorable impact on revenues from our FERC regulated pipelines during the quarter and year-to-date periods of 2013 compared to the quarter and year-to-date periods of 2012. Revenues were also favorably impacted by increasing tariff rates on certain of our non-FERC regulated pipelines. We estimate that the collective impact of these favorable rate changes increased revenues by over $18 million and $36 million, respectively, for the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012.

· BP NGL Acquisition — We acquired pipelines through the BP NGL Acquisition completed on April 1, 2012. During the first quarter of 2013, we benefited from a full period of ownership of these assets, which contributed approximately $27 million of aggregate revenues and approximately 264,000 barrels per day during the three-month period ended March 31, 2013.

· Weather-Related Downtime — During the second quarter of 2013, our Rangeland, South Saskatchewan and Co-Ed pipeline systems in Canada were shut down due to high river flow rates and flooding in the surrounding area. We estimate that the downtime on these pipelines impacted revenues by approximately $9 million and decreased volumes by approximately 44,000 and 22,000 barrels per day for the three- and six-month periods ended June 30, 2013, respectively.

Table of Contents

· Rail Impact — For both the three- and six-month comparable periods, volumes on our Bakken Area, Manito and Rainbow systems were negatively impacted by producer decisions to deliver more crude to rail loading facilities in the area. We estimate that the impact to revenues was approximately $5 million and $10 million for the three- and six-month periods ended June 30, 2013, respectively, and that volumes decreased by approximately 30,000 to 35,000 barrels per day for each of the respective periods.

· 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 decreased by approximately $14 million and $23 million, respectively, for the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012, primarily due to a lower average realized price per barrel (including the impact of gains and losses from derivative-related activities) and lower volumes, during each of the 2013 periods as compared to 2012 periods.

Additional noteworthy volume and revenue variances for the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 include (i) increased volumes and revenues on our All American pipeline due to increased production in 2013 and maintenance activities at the production facilities during 2012, (ii) decreases on both the Salt Lake City system and Line 63 due to lower refinery demand for pipeline barrels; however, revenues were consistent with the prior year's quarter due to movements on higher tariff segments on Line 63 and the receipt of contract payments on the Salt Lake City system and (iii) increased trucking volumes and revenues due to increased demand for production transported to rail and hauls from pipeline disruptions.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) increased during the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 primarily due to (i) higher environmental response, remediation and related repair expenses associated with pipeline releases of approximately $6 million and $22 million, respectively, for the three and six months ended June 30, 2013 over the three and six months ended June 30, 2012, (ii) higher payroll costs, primarily due to the BP NGL Acquisition, and (iii) approximately $4 million of cost incurred during the six months ended June 30, 2013 associated with the testing of certain lines that we considered bringing back into service. Excluding the impacts of the environmental response and remediation expenses, field operating costs in general remained relatively consistent on a per barrel basis during the comparable three-and six-month periods.

Equity-Indexed Compensation Expense. Equity-indexed compensation expense increased for the three months ended June 30, 2013 compared to the three months ended June 30, 2012, primarily due to (i) a greater number of units deemed probable of vesting for the three months ended June 30, 2013 than for the three months ended June 30, 2012 and (ii) a higher average fair value per unit in 2013 for those units deemed probable of vesting.

Equity-indexed compensation expense increased for the six months ended June 30, 2013 compared to the six months ended June 30, 2012, primarily due to (i) a more significant impact of the increase in unit price during the first half of 2013 compared to the impact of the increase during the first half of 2012, (ii) a greater number of units deemed probable of vesting for the first half of 2013 compared to the first half of 2012 and (iii) a higher average fair value per unit for those units deemed probable of vesting, partially offset by a less significant impact during the first half of 2013 compared to the increase during the first half of 2012 of the change in assumption of probable distribution levels. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for further information regarding our equity compensation plans.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The decrease in maintenance capital during the three months ended June 30, 2013 compared to the three months ended June 30, 2012 is primarily due to the reclassification of certain 2012 expansion projects initially classified as maintenance capital. The increase in maintenance capital during the six months ended June 30, 2013 compared to the six months ended June 30, 2012 is primarily due to increased investment on pipeline integrity projects.

Equity Earnings in Unconsolidated Entities. The favorable variance in equity earnings in unconsolidated entities for the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 was primarily due to increased earnings from our equity method investments as a result of (i) increased throughput on the White Cliffs pipeline, as discussed above, and (ii) increased capacity related to vessel additions and increased rates on services provided by Settoon Towing.

Table of Contents

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, natural gas and NGL, 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 leases and processing arrangements.

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

Operating Results [1] (in millions, except per barrel amounts)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Revenues [1]	$ 262	$ 225	$ 37	16%	$ 529	$ 390	$ 139	36%
Natural gas sales [2]	86	62	24	39%	174	133	41	31%
Storage related costs (natural gas related)	(3)	(5)	2	40%	(9)	(12)	3	25%
Natural gas sales costs [2]	(80)	(60)	(20)	(33)%	(165)	(127)	(38)	(30)%
Field operating costs (excluding equity-indexed compensation expense)	(94)	(86)	(8)	(9)%	(180)	(133)	(47)	(35)%
Equity-indexed compensation expense - operations [3]	—	—	—	—%	(1)	(1)	—	—%
Segment general and administrative expenses [4] (excluding equity-indexed compensation expense)	(16)	(18)	2	11%	(32)	(32)	—	—%
Equity-indexed compensation expense - general and	(6)	(4)	(2)	(50)%	(16)	(14)	(2)	(14)%

administrative [3]								
Segment profit	$ 149	$ 114	$ 35	31%	$ 300	$ 204	$ 96	47%
Maintenance capital	$ 11	$ 10	$ (1)	(10)%	$ 18	$ 17	$ (1)	(6)%
Segment profit per barrel	$ 0.41	$ 0.35	$ 0.06	17%	$ 0.42	$ 0.34	$ 0.08	24%

	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
Volumes [5] [6]	**2013**	**2012**	**Volumes**	**%**	**2013**	**2012**	**Volumes**	**%**
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	95	93	2	2%	94	85	9	11%
Rail load / unload volumes (average volumes in thousands of barrels per day)	231	—	231	N/A	223	—	223	N/A
Natural gas storage (average monthly capacity in billions of cubic feet)	97	80	17	21%	95	78	17	22%
NGL fractionation (average volumes in thousands of barrels per day)	90	108	(18)	(17)%	95	60	35	58%
Facilities segment total (average monthly volumes in millions of barrels)	121	109	12	11%	120	100	20	20%

---

(1) Revenues and expenses include intersegment amounts.

(2) Natural gas sales and costs are attributable to the activities performed by PNG's commercial optimization group.

(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.

(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 acquisitions represent total volumes for the number of months we actually owned 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 tables above, our Facilities segment revenues, less storage related costs and natural gas sales costs, and volumes increased for the three and six months ended June 30, 2013 compared to the same periods of 2012. The significant variances in revenues and average monthly volumes between the comparative periods are primarily due to our acquisitions and ongoing expansion activities as discussed below:

- Rail Terminal Acquisition and Expansion Projects — The USD Rail Terminal Acquisition completed in December 2012 and related internal growth projects completed during the latter portion of 2012 expanded our rail loading and unloading fee-based activities. These rail load and unload activities contributed approximately $26 million and $52 million to the increase in total revenues for the three and six months ended June 30, 2013 over the three and six months ended June 30, 2012, respectively, and increased average throughput volumes by approximately 231,000 and 223,000 barrels per day during the respective comparative periods.

- BP NGL Acquisition — We acquired NGL storage facilities, fractionation plants and related assets through the BP NGL Acquisition completed on April 1, 2012. During the first quarter of 2013, we benefited from a full period of ownership of these assets, which contributed approximately $66 million of aggregate revenues, 14 million barrels of average monthly capacity of NGL storage capacity, and 87,000 barrels per day of average NGL fractionation throughput during the three-month period ended March 31, 2013. See the bullet point below entitled "Fractionation and Processing Activities" for a discussion of the performance of these assets during the remainder of the 2013 period.

- Fractionation and Processing Activities — While NGL fractionation volumes decreased for the three months ended June 30, 2013 compared to the same 2012 period largely due to lower supply volumes related to the apportionment of certain third-party pipelines, we experienced favorable results in the aggregate related to these activities. The favorable results related to both our NGL fractionation and gas processing activities of approximately $15 million for the three months ended June 30, 2013 as compared to the same period ended June 30, 2012 were primarily related to physical processing gains recognized at certain owned facilities.

- Other Expansion Projects — We estimate that expansion projects that were completed in phases throughout recent years at some of our major terminal locations favorably impacted revenues for the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 by approximately $5 million and $10 million, respectively. Such projects included completed phases of expansions at our Cushing, Patoka, St. James and Yorktown terminals and new condensate stabilizers at our Gardendale terminal.

· Natural Gas Storage Activities — While our average monthly natural gas storage capacity increased due to expansions of the Pine Prairie and Southern Pines facilities, decreased storage rates on contracts executed to replace expiring contracts on existing capacity largely offset incremental revenues from our natural gas storage activities.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) increased during the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 due to our growth through acquisitions, primarily the BP NGL and USD Rail Terminal Acquisitions. Additionally, the BP NGL Acquisition assets and operations typically have a higher ratio of operating costs to revenue than our historic operations in this segment.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense increased during both the three and six months ended June 30, 2013 as compared to the three and six months ended June 30, 2012. See discussion regarding such variances under "—Transportation Segment" above. Also, see Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for further information regarding our equity 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. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. 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 gathered 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.

Table of Contents

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

Operating Results [1] **(in millions, except per barrel amounts)**	**Three Months Ended June 30, 2013**	**Three Months Ended June 30, 2012**	**Favorable/(Unfavorable) Variance $**	**Favorable/(Unfavorable) Variance %**	**Six Months Ended June 30, 2013**	**Six Months Ended June 30, 2012**	**Favorable/(Unfavorable) Variance $**	**Favorable/(Unfavorable) Variance %**
Revenues	$ 9,934	$ 9,442	$ 492	5%	$ 20,158	$ 18,319	$ 1,839	10%
Purchases and related costs [2]	(9,614)	(9,030)	(584)	(6)%	(19,249)	(17,638)	(1,611)	(9)%
Field operating costs (excluding equity-indexed compensation expense)	(109)	(105)	(4)	(4)%	(224)	(207)	(17)	(8)%
Equity-indexed compensation expense - operations [3]	(1)	(1)	—	—%	(2)	(1)	(1)	(100)%
Segment general and administrative expenses [4] (excluding equity-indexed compensation expense)	(27)	(27)	—	—%	(53)	(53)	—	—%
Equity-indexed compensation expense - general and administrative [3]	(7)	(5)	(2)	(40)%	(20)	(18)	(2)	(11)%
Segment profit	$ 176	$ 274	$ (98)	(36)%	$ 610	$ 402	$ 208	52%
Maintenance capital	$ 5	$ 3	$ (2)	(67)%	$ 9	$ 7	$ (2)	(29)%
Segment profit per barrel	$ 1.89	$ 3.10	$ (1.21)	(39)%	$ 3.11	$ 2.32	$ 0.79	34%

Average Daily Volumes (in thousands of barrels per day)	**Three Months Ended June 30, 2013**	**Three Months Ended June 30, 2012**	**Favorable/(Unfavorable) Variance Volumes**	**Favorable/(Unfavorable) Variance %**	**Six Months Ended June 30, 2013**	**Six Months Ended June 30, 2012**	**Favorable/(Unfavorable) Variance Volumes**	**Favorable/(Unfavorable) Variance %**
Crude oil lease gathering purchases	853	814	39	5%	855	806	49	6%
NGL sales	160	153	7	5%	221	144	77	53%
Waterborne cargos	7	4	3	75%	6	2	4	200%
Supply and Logistics segment total	1,020	971	49	5%	1,082	952	130	14%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged crude oil and NGL inventory) of approximately $5 million and $10 million for the three and six months ended June 30, 2013 compared to $4 million and $6 million for the three and six months ended June 30, 2012, respectively.

(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.

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

The NYMEX benchmark price of crude oil ranged from approximately $86 to $99 per barrel and $77 to $106 per barrel during the three months ended June 30, 2013 and 2012, respectively, and from $86 to $99 per barrel and $77 to $111 per barrel during the six months ended June 30, 2013 and 2012, 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, 2013 and 2012 primarily from increased volumes in 2013.

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 and excluding gains and losses from derivative activities (see the "Impact from Derivative Activities" section below), increased for the six months ended June 30, 2013 compared to the six months ended June 30, 2012; however, such results decreased for the comparative three-month periods ended June 30, 2013 and 2012. The following factors contributed to the variances in revenues and volumes between the comparative periods:

- North American Crude Oil Production and Related Market Economics — The increasing production of oil and liquids-rich gas in North America over the last several years generally created supply and demand imbalances that increased the volatility of historical differentials for various grades of crude oil and also impacted the historical pricing relationship between NGL and crude oil. Lack of existing pipeline takeaway capacity and associated logistical challenges in certain of these producing regions created market conditions and opportunities that were favorable to our supply and logistics activities. However, infrastructure additions in many of these resource plays during the second quarter of 2013 began to relieve certain of the transportation constraints that had previously created opportunities for these favorable crude oil margins. For the six months ended June 30, 2013, we had higher net revenues associated with our crude oil activities than in the comparable 2012 period. During the first quarter of 2013, as well as the second quarter of 2012, the conditions described above provided opportunities for increased margins related to opportunities in certain producing regions where crude oil production volumes exceeded existing takeaway capacity and where there were associated logistical challenges. In addition, we benefited from higher volumes and opportunities from more favorable crude oil quality and location differentials. During the second quarter of 2013, we continued to have higher volumes than in the comparable prior year period, but experienced fewer opportunities for favorable crude oil margins resulting in lower overall results from our crude oil activities.

  We believe the fundamentals of our business remain strong; however, as the midstream infrastructure in these producing regions 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 2012 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 increased during the three and six months ended June 30, 2013 as compared to the three and six months ended June 30, 2012 primarily due to more favorable market prices and higher demand related to (i) increases in export activity that reduced overall product availability in the market and (ii) petrochemical demand as well as more favorable supply contracts. Additionally, NGL margins during the three-month 2012 period were negatively impacted by the sale of NGL product at points in time where spot prices were less than our weighted average inventory cost, primarily associated with inventory acquired in the BP NGL Acquisition on April 1, 2012. The six-month comparative periods further benefited from higher demand related to heating requirements during an extended winter season.

  NGL sales volumes increased during the six months ended June 30, 2013 over the six months ended June 30, 2012 primarily due to increased demand as discussed above, as well as the impact from our BP NGL Acquisition completed on April 1, 2012.

Impact from Derivative Activities. The mark-to-market valuation of our derivative activities impacted our net revenues for the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 as shown in the table below (in millions):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Variance	2013	2012	Variance
Gains/(losses) from derivative activities [1]	$ 27	$ 73	$ (46)	$ 51	$ 13	$ 38

[1] Includes mark-to-market gains and losses resulting from 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 11 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and risk management activities.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) increased in the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 primarily related to increased lease gathered volumes, particularly in West Texas and Oklahoma.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense increased during both the three and six months ended June 30, 2013 as compared to the three and six months ended June 30, 2012. See discussion regarding such variances under "—Transportation

Segment" above. Also, see Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for further information regarding our equity compensation plans.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was approximately $91 million and $173 million for the three and six months ended June 30, 2013, respectively, compared to approximately $86 million and $146 million for the three and six months ended June 30, 2012, respectively. The increase in the 2013 periods over the comparative 2012 periods were primarily the result of an increased amount of assets resulting from acquisition activities, as well as various internal growth projects in both years.

Interest Expense

Interest expense increased by approximately $12 million for the six months ended June 30, 2013 compared to the six months ended June 30, 2012, primarily as a result of the issuance of approximately $1.25 billion of senior notes in March 2012, the proceeds of which were used to fund the BP NGL Acquisition, and the issuance of approximately $750 million of senior notes in December 2012, the proceeds of which were used primarily to fund our growth through acquisitions and our ongoing capital program. The resulting increases in interest expense were partially offset by the maturity of our $500 million, 4.25% senior notes in September 2012.

Income Tax Expense

Income tax expense for the three months ended June 30, 2013 compared to the three months ended June 30, 2012 increased by approximately $8 million, primarily as a result of increased earnings of our existing Canadian operations.

Income tax expense for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 increased by approximately $40 million, primarily as a result of the BP NGL Acquisition, as well as the strength of our existing operations, both of which increased the proportion of earnings subject to Canadian federal and provincial taxes. Canadian withholding taxes also increased on interest from our Canadian entities to other affiliates.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) our cash flows from operating activities, (ii) borrowings under our 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 and other products and other expenses and interest payments on our outstanding debt, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through our primary sources of liquidity. 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 operating cash flows, borrowings under our credit facilities, and/or the issuance of additional equity or debt securities. As of June 30, 2013, we had a working capital deficit of approximately $83 million and approximately $2.57 billion of liquidity available to meet our other ongoing operating, investing and financing needs as noted below (in millions):

	As of June 30, 2013
Availability under PAA senior unsecured revolving credit facility	$ 1,548
Availability under PAA senior secured hedged inventory facility	802
Availability under PNG senior unsecured revolving credit facility	204
Cash and cash equivalents	16
Total	$ 2,570

We believe that we will continue to have the ability to access our 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 2012 Annual Report on Form 10-K for

further discussion regarding such risks that may impact our liquidity and capital resources. Usage of our credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

Cash Flows from Operating Activities

For a comprehensive discussion of the primary drivers of our 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 Operations" under Item 7 of our 2012 Annual Report on Form 10-K.

Net cash provided by operating activities for the first six months of 2013 was approximately $1.337 billion. The cash provided by operating activities reflects cash generated by our recurring operations, and can also be significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During the first half of 2013, we decreased the amount of our inventory. The decrease in inventory was primarily due to the sale of NGL inventory related to higher product demand caused by increases in (i) heating requirements during an extended 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 flows from operating activities.

Net cash provided by operating activities for the first six months of 2012 was approximately $348 million, primarily resulting from earnings from our operations. Cash flows from earnings were partially offset by increases in our crude oil and NGL inventory levels.

Equity and Debt Financing Activities

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

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, 2013, we had approximately $1.6 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.

PNG has filed with the SEC a universal shelf registration statement ("PNG Shelf") that, subject to effectiveness at the time of use, allows PNG to issue up to an aggregate of $1.0 billion of debt or equity securities. All issuances of equity securities associated with PNG's continuous offering program, as discussed further below, have been issued pursuant to the PNG Shelf. At June 30, 2013, PNG had approximately $969 million of unsold securities available under the PNG Shelf.

PAA Continuous Offering Programs

During the six months ended June 30, 2013, we issued an aggregate of approximately 5.9 million common units under our continuous offering programs, generating net proceeds of approximately $331 million, including our general partner's proportionate capital contribution. The net proceeds from sales were used for general partnership purposes.

PNG Continuous Offering Program

On March 18, 2013, PNG entered into an equity distribution agreement with a financial institution pursuant to which PNG may offer and sell, through its sales agent, common units representing limited partner interests having an aggregate offering price of up to $75 million. Through June 30, 2013, PNG has issued an aggregate of approximately 1.4 million common units under this agreement, generating net proceeds of approximately $30 million, excluding our proportionate capital contribution for our general partner interest.

Credit Agreements

General. During the six months ended June 30, 2013, we had net repayments on our credit agreements, which include our revolving credit facilities and our hedged inventory facility, in the aggregate of approximately $186 million. These net repayments resulted primarily from cash flows from operating activities, such as sales of crude oil and NGL inventory that was liquidated during the period, as well as our equity activities.

During the six months ended June 30, 2012, we had net borrowings on our credit agreements in the aggregate of approximately $345 million. These net borrowings resulted primarily when we increased our crude oil inventory levels related to storing barrels in the contango market. For further discussion related to our credit facilities and long-term debt, see "Cash Flows from Operating Activities" above and "Liquidity and Capital Resources—Credit Facilities and Indentures" under Item 7 of our 2012 Annual Report on Form 10-K.

Acquisitions and Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests

We also use cash for our acquisition activities, internal growth projects and distributions paid to our unitholders, general partner and noncontrolling interests. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by the operating and financing activities discussed above. See "Internal Growth Projects" above and "Acquisitions and Internal Growth Projects" under Item 7 of our 2012 Annual Report on Form 10-K for further discussion of such capital expenditures.

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 acquisitions and the timing of certain cash payments, the net cash paid may differ significantly from the total price of acquisitions completed during the year.

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, 2013, we will pay a quarterly distribution of $0.5875 per limited partner unit. This distribution represents a year-over-year distribution increase of approximately 10.3%. See Note 9 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 2012 Annual Report on Form 10-K for additional discussion on distributions.

Distributions to noncontrolling interests. We paid approximately $24 million for distributions to noncontrolling interests during each of the six months ended June 30, 2013 and 2012. These amounts represent distributions paid on interests in PNG and SLC that are not owned by us.

We believe that we have sufficient liquid assets, cash flow from operations 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 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 12 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. 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 buy/sell contracts and those subject to a net settlement arrangement with the counterparty. 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, 2013 (in millions):

	2013	2014	2015	2016	2017	2018 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 422	$ 332	$ 873	$ 773	$ 666	$ 7,359	$ 10,425
Leases (2)	67	138	120	107	80	399	911
Other obligations (3)	140	97	63	36	27	147	510
Subtotal	629	567	1,056	916	773	7,905	11,846
Crude oil, natural gas, NGL and other purchases (4)	5,649	2,492	1,736	1,564	1,119	2,387	14,947
Total	$ 6,278	$ 3,059	$ 2,792	$ 2,480	$ 1,892	$ 10,292	$ 26,793

(1) Includes debt service payments, interest payments due on our senior notes, interest payments on long-term borrowings outstanding under the PNG credit agreement and the commitment fee on assumed available capacity on the PAA and PNG revolving credit facilities. Although there are outstanding short-term borrowings on the PAA and PNG revolving credit facilities at June 30, 2013, 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) 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 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 long-term liability of approximately $3 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 2013. 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 our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At June 30, 2013 and December 31, 2012, we had outstanding letters of credit of approximately $50 million and $24 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 2012 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 statements regarding our business strategy, plans and objectives for future operations. The absence of such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- 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);
- 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;
- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;
- tightened capital markets or other factors that increase our cost of capital or limit our 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 effectiveness of our risk management activities;
- 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;
- shortages or cost increases of supplies, materials or labor;
- 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 availability of, and our ability to consummate, acquisition or combination opportunities;
- 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;
- interruptions in service on third-party pipelines;

- 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;
- the currency exchange rate of the Canadian dollar;
- weather interference with business operations or project construction;
- risks related to the development and operation of 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 2012 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 stored inventory 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 and stored inventory. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

Table of Contents

See Note 11 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, 2013 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	$ 19	$ 20	$ (16)
Natural gas	(3)	$ (4)	$ 4
NGL and other	57	$ 7	$ (7)
Total fair value	$ 73		

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, 2013, approximately $850 million (which excludes $100 million of variable rate debt when giving consideration to our interest rate derivatives that swap floating-rate debt for fixed), is subject to interest rate re-sets, which range from one week to three months. The average interest rate of approximately 1.7% is based upon rates in effect during the six months ended June 30, 2013 without giving consideration to our interest rate swaps. The fair value of our interest rate derivatives is an unrealized gain of approximately $12 million as of June 30, 2013. A 10% increase in the forward LIBOR curve as of June 30, 2013 would result in an increase of approximately

$26 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of June 30, 2013 would result in a decrease of approximately $26 million to the fair value of our interest rate derivatives. See Note 11 to our condensed consolidated financial statements for a discussion of our interest rate risk hedging activities.

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 our 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 12 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 2012 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 7, 2013

By: /s/ GREG L. ARMSTRONG
Greg L. Armstrong, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*

Date: August 7, 2013

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

Date: August 7, 2013

By: /s/ CHRIS HERBOLD
Chris Herbold, *Vice President- Accounting and Chief Accounting Officer*

Table of Contents

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	—	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).
3.4	—	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).
3.5	—	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).
3.6	—	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).
3.7	—	Fifth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated December 23, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed December 30, 2010).
3.8	—	Sixth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 23, 2010 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed December 30, 2010).
3.9	—	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).
3.10	—	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).
3.11	—	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	—	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 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 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.3	—	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).
4.4	—	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

Table of Contents

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).

4.5	—	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).
4.6	—	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).
4.7	—	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).
4.8	—	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).
4.9	—	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).
4.10	—	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).
4.11	—	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).
4.12	—	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).
4.13	—	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).
4.14	—	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).
4.15	—	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).
4.16	—	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).
10. 1	—	Form of PAA LTIP Grant Letter for Officers (February 2013) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2013).

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.

EXHIBIT 12.1

STATEMENT OF COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions)

	Six Months Ended June 30, 2013	Year Ended December 31, 2012	2011	2010	2009	2008
EARNINGS [(1)]						
Pre-tax income from continuing operations before noncontrolling interest and income from equity investees	$ 884	$ 1,143	$ 1,026	$ 510	$ 572	$ 430
add: Fixed charges	207	380	328	321	283	264
add: Distributed income of equity investees	21	40	23	9	7	10
add: Amortization of capitalized interest	2	2	2	1	1	1
less: Capitalized interest	(19)	(36)	(25)	(16)	(12)	(17)
Total Earnings	$ 1,095	$ 1,529	$ 1,354	$ 825	$ 851	$ 688
FIXED CHARGES [(1)]						
Interest expensed and capitalized [(2)]	$ 181	$ 336	$ 298	$ 281	$ 247	$ 233
Amortization of debt expense	5	10	10	8	7	4
Portion of rent expense related to interest (33.33%)	21	34	20	32	29	27
Total Fixed Charges	$ 207	$ 380	$ 328	$ 321	$ 283	$ 264
RATIO OF EARNINGS TO FIXED CHARGES [(3)]	5.29x	4.03x	4.13x	2.57x	3.00x	2.60x

---

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pre-tax income from continuing operations before income from equity investees plus fixed charges (excluding capitalized interest), distributed income of equity investees and amortization of capitalized interest. "Fixed charges" represents interest incurred (whether expensed or capitalized), amortization of debt expense (including discounts and premiums relating to indebtedness) and the portion of rental expense on leases deemed to be the equivalent of interest.

(2) Includes interest costs attributable to borrowings for hedged inventory purchases of $10 million for the six months ended June 30, 2013 and $12 million, $20 million, $17 million, $11 million and $21 million for the years ended December 31, 2012, 2011, 2010, 2009 and 2008, respectively.

(3) Ratios may not recalculate due to rounding.

EXHIBIT 31.1

CERTIFICATION

I, Greg L. Armstrong, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 7, 2013

/s/ GREG L. ARMSTRONG

Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Al Swanson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 7, 2013

/s/ AL SWANSON
Al Swanson
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended June 30, 2013 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ GREG L. ARMSTRONG
Name: Greg L. Armstrong
Date: August 7, 2013

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Al Swanson, Chief Financial Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended June 30, 2013 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ AL SWANSON
Name: Al Swanson
Date: August 7, 2013