UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) **August 5, 2013**

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**1-14569**	**76-0582150**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

Registrant s telephone number, including area code: **713-646-4100**

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated August 5, 2013

Item 2.02 and Item 7.01. Results of Operations and Financial Condition; Regulation FD Disclosure

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its second-quarter 2013 results. We are furnishing the press release, attached as Exhibit 99.1, pursuant to Item 2.02 and Item 7.01 of Form 8-K. Pursuant to Item 7.01, we are also providing detailed guidance for financial performance for the third and fourth quarters and full year of 2013. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under Item 2.02 and Item 7.01 shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Disclosure of Third and Fourth Quarter 2013 Guidance; Update of Full Year 2013 Guidance

We based our guidance for the three-month period ending September 30, 2013 and three-month and twelve-month periods ending December 31, 2013 on assumptions and estimates that we believe are reasonable, given our assessment of historical trends (modified for changes in market conditions), business cycles and other reasonably available information. Projections covering multi-quarter periods contemplate inter-period changes in future performance resulting from new expansion projects, seasonal operational changes (such as NGL sales) and acquisition synergies. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so we can provide no assurance that actual performance will fall within the guidance ranges. Please refer to information under the caption Forward-Looking Statements and Associated Risks below. These risks and uncertainties, as well as other unforeseeable risks and uncertainties, could cause our actual results to differ materially from those in the following table. The operating and financial guidance provided below is given as of the date hereof, based on information known to us as of August 4, 2013. We undertake no obligation to publicly update or revise any forward-looking statements.

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as non-GAAP financial measures in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations 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. EBIT and EBITDA (each as defined below in Note 1 to the Operating and Financial Guidance table) are non-GAAP financial measures. Net income represents one of the two most directly comparable GAAP measures to EBIT and EBITDA. In Note 9 below, we reconcile net income to EBIT and EBITDA for the 2013 guidance periods presented. Cash flows from operating activities is the other most comparable GAAP measure. We do not, however, reconcile cash flows from operating activities to EBIT and EBITDA, because such reconciliations are impractical for forecasted periods. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled Non-GAAP Reconciliations), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. In addition, within our guidance, we have highlighted the impact of (i) equity-indexed compensation expense, (ii) tax effect on selected items impacting comparability, (iii) net gain on foreign currency revaluation, (iv) gains/(losses) from derivative activities and (v) other selected items impacting comparability. Due to the nature of the selected items, certain selected items impacting comparability may impact certain non-GAAP financial measures but not impact other non-GAAP financial measures.

Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	Actual 6 Months Ended June 30, 2013	Guidance (a) 3 Months Ending September 30, 2013 Low	3 Months Ending September 30, 2013 High	3 Months Ending December 31, 2013 Low	3 Months Ending December 31, 2013 High	12 Months Ending December 31, 2013 Low	12 Months Ending December 31, 2013 High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 2,113	$ 820	$ 855	$ 908	$ 943	$ 3,841	$ 3,911
Field operating costs	(684)	(344)	(334)	(320)	(310)	(1,348)	(1,328)
General and administrative expenses	(196)	(86)	(81)	(84)	(79)	(366)	(356)
	1,233	390	440	504	554	2,127	2,227
Depreciation and amortization expense	(173)	(91)	(86)	(92)	(87)	(356)	(346)
Interest expense, net	(152)	(84)	(80)	(85)	(81)	(321)	(313)
Income tax expense	(70)	(11)	(7)	(23)	(19)	(104)	(96)
Other income / (expense), net	(1)	1	1	1	1	1	1
Net Income	**837**	**205**	**268**	**305**	**368**	**1,347**	**1,473**
Net income attributable to noncontrolling interests	(16)	(6)	(6)	(9)	(9)	(31)	(31)
Net Income Attributable to Plains	**$ 821**	**$ 199**	**$ 262**	**$ 296**	**$ 359**	**$ 1,316**	**$ 1,442**
Net Income to Limited Partners (b)	$ 631	$ 101	$ 163	$ 191	$ 253	$ 923	$ 1,047
Basic Net Income Per Limited Partner Unit (b)							
Weighted Average Units Outstanding	338	343	343	345	345	341	341
Net Income Per Unit	$ 1.85	$ 0.29	$ 0.47	$ 0.55	$ 0.73	$ 2.69	$ 3.05
Diluted Net Income Per Limited Partner Unit (b)							
Weighted Average Units Outstanding	341	345	345	347	347	344	344
Net Income Per Unit	$ 1.84	$ 0.29	$ 0.47	$ 0.54	$ 0.72	$ 2.67	$ 3.03
EBIT	**$ 1,059**	**$ 300**	**$ 355**	**$ 413**	**$ 468**	**$ 1,772**	**$ 1,882**
EBITDA	**$ 1,232**	**$ 391**	**$ 441**	**$ 505**	**$ 555**	**$ 2,128**	**$ 2,228**
Selected Items Impacting Comparability							
Equity-indexed compensation expense	$ (39)	$ (14)	$ (14)	$ (13)	$ (13)	$ (66)	$ (66)
Tax effect on selected items impacting comparability	(6)					(6)	(6)
Net gain on foreign currency revaluation	4					4	4
Gains/(losses) from derivative activities	50					50	50
Other	1	1	1			2	2
Selected Items Impacting Comparability of Net Income attributable to Plains	$ 10	$ (13)	$ (13)	$ (13)	$ (13)	$ (16)	$ (16)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 341	$ 199	$ 209	$ 222	$ 232	$ 762	$ 782
Facilities	310	130	140	150	160	590	610
Supply and Logistics	561	75	105	145	175	781	841
Other income, net	5	1	1	1	1	7	7
Adjusted EBITDA	$ 1,217	$ 405	$ 455	$ 518	$ 568	$ 2,140	$ 2,240
Adjusted Net Income Attributable to Plains	$ 811	$ 212	$ 275	$ 319	$ 372	$ 1,332	$ 1,458

Basic Adjusted Net Income Per Limited Partner Unit (b)	$	1.83	$	0.33	$	0.51	$	0.58	$	0.76	$	2.74	$	3.10
Diluted Adjusted Net Income Per Limited Partner Unit (b)	$	1.82	$	0.33	$	0.51	$	0.57	$	0.75	$	2.72	$	3.08

(a) The projected average foreign exchange rate is $1.00 Canadian to $1.00 U.S. for the three-month periods ending September 30, 2013 and December 31, 2013. The rate as of August 2, 2013 was $1.00 Canadian to $0.96 U.S. A $0.05 change in the FX rate will impact annual adjusted EBITDA by approximately $12 million.

(b) 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.

Notes and Significant Assumptions:

1. *Definitions.*

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Segment Profit	Net revenues (including equity earnings, as applicable) less field operating costs and segment general and administrative expenses
DCF	Distributable Cash Flow
FASB	Financial Accounting Standards Board
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
NGL	Natural gas liquids. Includes ethane and natural gasoline products as well as propane and butane, which are often referred to as liquefied petroleum gas (LPG). When used in this document NGL refers to all NGL products including LPG.
FX	Foreign currency exchange
General partner (GP)	As the context requires, general partner or GP refers to any or all of (i) PAA GP LLC, the owner of our 2% general partner interest, (ii) Plains AAP, L.P., the sole member of PAA GP LLC and owner of our incentive distribution rights and (iii) Plains All American GP LLC, the general partner of Plains AAP, L.P.

2. *Operating Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. The following is a brief explanation of the operating activities for each segment as well as key metrics.

a. *Transportation.* Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and other transportation fees. Our transportation segment also includes our equity earnings from our investments in Settoon Towing and the White Cliffs, Butte, Frontier and Eagle Ford pipeline systems, in which we own non-controlling interests.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and assumed completion of internal growth projects. Actual volumes will be influenced by maintenance schedules at refineries, production trends, weather and other natural occurrences, changes in the quantity of inventory held in tanks, and other external factors beyond our control. We forecast adjusted segment profit using the volume assumptions in the table below, priced at forecasted tariff rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation. Actual segment profit could vary materially depending on the level and mix of volumes transported or expenses incurred during the period. The following table summarizes our total transportation volumes and highlights major systems that are significant either in total volumes transported or in contribution to total Transportation segment profit.

	Actual Six Months Ended Jun 30, 2013	**Three Months Ending Sep 30, 2013**	**Guidance Three Months Ending Dec 31, 2013**	**Twelve Months Ending Dec 31, 2013**
Average Daily Volumes (MBbls/d)				
Crude Oil / Refined Products Pipelines				
All American	39	40	40	40
Bakken Area Systems	127	130	135	130

Basin/Mesa	702	700	675	695
Capline	157	160	160	159
Eagle Ford Area Systems	61	130	195	112
Line 63 / 2000	113	105	105	109
Manito	46	45	45	45
Mid-Continent Area Systems	261	270	285	269
Permian Basin Area Systems	513	605	675	577
Rainbow	124	125	125	125
Rangeland	62	60	60	61
Salt Lake City Area Systems	133	145	140	138
South Saskatchewan	46	55	55	51
White Cliffs	21	25	25	23
Other	868	835	760	832
NGL Pipelines				
Co-Ed	54	55	55	55
Other	186	170	165	177
	3,513	3,655	3,700	3,598
Trucking	109	110	110	110
	3,622	3,765	3,810	3,708
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.52	$ 0.59(1)	$ 0.65(1)	$ 0.57(1)

(1) Mid-point of guidance.

b. *Facilities*. 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. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and redeliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (v) revenues from the sale of natural gas, (vi) fees from NGL fractionation and isomerization and (vii) fees from gas and condensate processing services. Adjusted segment profit is forecasted using the volume assumptions in the table below, priced at forecasted rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation.

	Actual		**Guidance**	
	Six Months Ended Jun 30, 2013	**Three Months Ending Sep 30, 2013**	**Three Months Ending Dec 31, 2013**	**Twelve Months Ending Dec 31, 2013**
Operating Data				
Crude Oil, Refined Products, and NGL Terminalling and Storage (MMBbls/Mo.)	94	95	96	95
Rail Load / Unload Volumes (MBbl/d)	223	250	305	250
Natural Gas Storage (Bcf/Mo.)	95	97	97	96
NGL Fractionation (MBbls/d)	95	100	110	100
Facilities Activities Total Avg. Capacity (MMBbls/Mo.) (1)	120	122	125	122
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.43	$ 0.37(2)	$ 0.41(2)	$ 0.41(2)

(1) 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.

(2) Mid-point of guidance.

c. *Supply and Logistics*. Our Supply and Logistics segment operations generally consist of the following merchant-related activities:

- the purchase of U.S. and Canadian crude oil at the wellhead, the bulk purchase of crude oil at pipeline, terminal and rail facilities, and the purchase of cargos at their load port and various other locations in transit;

- the storage of inventory during contango market conditions and the seasonal storage of NGL;

- the purchase of NGL from producers, refiners, processors and other marketers;

- the resale or exchange of crude oil and NGL at various points along the distribution chain to refiners or other resellers to maximize profits; and

- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and ocean-going vessels from various delivery points to market hub locations or directly to end users such as refineries, processors and fractionation facilities.

We characterize a substantial portion of our baseline profit generated by our Supply and Logistics segment as fee equivalent. This portion of the segment profit is generated by the purchase and resale of crude oil on an index-related basis, which results in us generating a gross margin for such activities. This gross margin is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil to market as well as any operating and general and administrative expenses. The level of profit associated with a portion of the other activities we conduct in the Supply and Logistics segment is influenced by overall market structure and the degree of volatility in the crude oil market, as well as variable operating expenses. Forecasted operating results for the three-month period ending September 30, 2013 reflect the current market structure and for the last six months of 2013 reflect the seasonal, weather-related variations in NGL sales. Our second-half guidance reflects an expectation for less favorable crude oil market conditions than those experienced during the first half of the year. Variations in weather, market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast adjusted segment profit using the volume assumptions stated below, as well as estimates of unit margins, field operating costs, G&A expenses and carrying costs for contango inventory, based on current and anticipated market conditions. Actual volumes are influenced by temporary market-driven storage and withdrawal of oil, maintenance schedules at refineries, actual production levels, weather, and other external factors beyond our control. Field operating costs do not include depreciation. Realized unit margins for any given lease-gathered barrel could vary significantly based on a variety of factors including location and quality differentials as well as contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Actual		**Guidance**
	Six Months	**Three Months**	