PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
August 04, 2010

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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 4, 2010
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))

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Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated August 4, 2010.

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 2010 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 providing detailed guidance for financial performance for the third and fourth quarters of calendar 2010 and updating our previous guidance for financial performance for the full calendar year of 2010 (which supersedes guidance pertaining to 2010 contained in our Form 8-K furnished on May 5, 2010). In accordance with General Instruction B.2. of Form 8-K, the information presented herein under this 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 2010 Guidance; Update of Full Year 2010 Guidance

EBIT and EBITDA (each as defined below in Note 1 to the Operating and Financial Guidance table) are non-GAAP financial measures. Net income and cash flows from operating activities are the most directly comparable GAAP measures to EBIT and EBITDA. In Note 9 below, we reconcile net income to EBIT and EBITDA for the 2010 guidance periods presented. We do not, however, reconcile cash flows from operating activities to EBIT and EBITDA because such reconciliations are impractical for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled Non-GAAP Reconciliation), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. We present EBIT and EBITDA because we believe they provide additional information with respect to both the performance of our fundamental business activities and our ability to meet our future debt service, capital expenditures and working capital requirements. We also believe that debt holders commonly use EBITDA to analyze partnership performance. In addition, we have highlighted the impact of our equity compensation plans, gains and losses from other derivative activities, net loss on early repayment of senior notes, and PNGS contingent consideration fair value adjustment on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

We based our guidance for the three months ending September 30 and December 31, 2010 and twelve months ending December 31, 2010 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 LPG sales) and acquisition synergies. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so no assurance can be provided 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 3, 2010. We undertake no obligation to publicly update or revise any forward-looking statements.

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Plains All American Pipeline, L.P.
Operating and Financial Guidance
(in millions, except per unit data)

	Actual 6 Months Ended 6/30/2010	Guidance [1] 3 Months Ending September 30, 2010 Low	High	3 Months Ending December 31, 2010 Low	High	12 Months Ending December 31, 2010 Low	High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 987	$ 470	$ 488	$ 492	$ 510	$ 1,949	$ 1,985
Field operating costs	(334)	(184)	(179)	(175)	(170)	(693)	(683)
General and administrative expenses	(117)	(54)	(52)	(54)	(52)	(225)	(221)
	536	232	257	263	288	1,031	1,081
Depreciation and amortization expense	(131)	(63)	(61)	(61)	(59)	(255)	(251)
Interest expense, net	(120)	(67)	(65)	(64)	(62)	(251)	(247)
Income tax expense		(1)		(1)		(2)	
Other income (expense), net	(1)	(6)	(6)			(7)	(7)
Net Income	**$ 284**	**$ 95**	**$ 125**	**$ 137**	**$ 167**	**$ 516**	**$ 576**
Less: Net income attributable to the noncontrolling interest	(2)	(3)	(3)	(3)	(3)	(8)	(8)
Net Income attributable to Plains	**$ 282**	**$ 92**	**$ 122**	**$ 134**	**$ 164**	**$ 508**	**$ 568**
Net Income to Limited Partners	$ 201	$ 51	$ 80	$ 90	$ 120	$ 342	$ 401
Basic Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	136	136	136	136	136	136	136
Net Income Per Unit	$ 1.45	$ 0.36	$ 0.57	$ 0.65	$ 0.87	$ 2.47	$ 2.90
Diluted Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	137	137	137	137	137	137	137
Net Income Per Unit	$ 1.45	$ 0.35	$ 0.57	$ 0.65	$ 0.86	$ 2.46	$ 2.90
EBIT	**$ 404**	**$ 163**	**$ 190**	**$ 202**	**$ 229**	**$ 769**	**$ 823**
EBITDA	**$ 535**	**$ 226**	**$ 251**	**$ 263**	**$ 288**	**$ 1,024**	**$ 1,074**

Selected Items Impacting Comparability														
Equity compensation charge	$	(24)	$	(8)	$	(8)	$	(7)	$	(7)	$	(39)	$	(39)
Inventory Valuation Adjustments Net of Gains/(Losses) from related derivative activities		(1)										(1)		(1)
Gains / (Losses) from other derivative activities		41										41		41
Net loss on early repayment of senior notes				(6)		(6)						(6)		(6)
PNGS contingent consideration fair value adjustment		(2)										(2)		(2)
	$	14	$	(14)	$	(14)	$	(7)	$	(7)	$	(7)	$	(7)

Excluding Selected Items Impacting Comparability														
Adjusted Segment Profit														
Transportation	$	269	$	132	$	137	$	143	$	148	$	544	$	554
Facilities		134		68		72		65		69		267		275
Supply and Logistics		120		40		56		62		78		222		254
Other Income (Expense), net		(2)										(2)		(2)
Adjusted EBITDA	$	521	$	240	$	265	$	270	$	295	$	1,031	$	1,081
Adjusted Net Income attributable to Plains	$	268	$	106	$	136	$	141	$	171	$	515	$	575
Adjusted Basic Net Income per Limited Partner Unit	$	1.35	$	0.46	$	0.67	$	0.70	$	0.92	$	2.51	$	2.94
Adjusted Diluted Net Income per Limited Partner Unit	$	1.34	$	0.45	$	0.67	$	0.70	$	0.91	$	2.50	$	2.93

(1) The projected average foreign exchange rate is $1.05 Canadian dollar to $1 U.S. Dollar, for the remainder of 2010. The rate as of August 3, 2010 was

$1.024 Canadian dollar to $1 U.S. Dollar. A $0.10 change in the FX rate will impact forecasted EBITDA for the last six months of 2010 by approximately $7 million.

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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
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other natural gas-related petroleum products (primarily propane and butane)
FX	Foreign currency exchange
General partner (GP)	As the context requires, general partner 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.
Class B units	Class B units 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 refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in the Butte and Frontier pipeline systems and Settoon Towing, in which we own noncontrolling 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 declines, weather and other natural disasters including hurricanes, 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 pipeline volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

	Actual	2010 Guidance		
	Six Months Ended June 30,	Three Months Ending September 30,	Three Months Ending December 31,	Twelve Months Ending December 31,
Average Daily Volumes (000 Bbls/d)				
All American	41	40	40	41
Basin	363	395	390	378

Capline	203	260	250	229
Line 63 / 2000	111	110	115	112
Salt Lake City Area Systems [1]	132	140	135	135
West Texas / New Mexico Area Systems [1]	376	400	385	384
Rainbow	195	185	190	191
Manito	60	60	60	60
Rangeland	51	50	50	51
Refined Products	121	120	120	120
Other	1,193	1,210	1,185	1,195
	2,846	2,970	2,920	2,896
Trucking	92	90	90	91
	2,938	3,060	3,010	2,987
Segment Profit per Barrel ($/Bbl) Excluding Selected Items Impacting Comparability	$ 0.51	$ 0.48[2]	$ 0.53[2]	$ 0.50[2]

[1] The aggregate of multiple systems in the respective areas.

[2] Mid-point of guidance.

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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, LPG and natural gas, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

Adjusted segment profit is forecast 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	2010 Guidance		
	Six Months Ended June 30,	Three Months Ending September 30,	Three Months Ending December 31,	Twelve Months Ending December 31,
Operating Data				
Crude oil, refined products and LPG storage (MMBbls/Mo.)	60	62	62	61
Natural Gas Storage (Bcf/Mo.)	45	50	50	48
LPG Processing (MBbl/d)	13	19	18	16
Facilities Activities Total [1] Avg. Capacity (MMBbls/Mo.)	68	71	71	69
Segment Profit per Barrel ($/Bbl) Excluding Selected Items Impacting Comparability	$ 0.33	$ 0.33[2]	$ 0.32[2]	$ 0.32[2]

(1) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to barrel of crude oil ratio; and (iii) LPG processing 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 activities:

- the purchase of crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of LPG;
- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

The level of profit 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 remainder of 2010 reflect the current market structure and seasonal, weather-related variations in LPG sales. The fourth quarter of 2010 reflects our expectation of normal winter weather for our LPG business. 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, production declines, 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, quality and contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

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	Actual Six Months Ended June 30,	2010 Guidance Three Months Ending September 30,	Three Months Ending December 31,	Twelve Months Ending December 31,
Average Daily Volumes (MBbl/d)				
Crude Oil Lease Gathering Purchases	611	625	610	614
LPG Sales	94	72	164	106
Refined Products Sales	41	48	58	47
Waterborne foreign crude oil imported	73	70	65	70
	819	815	897	837
Segment Profit per Barrel ($/Bbl) Excluding Selected Items Impacting Comparability	$ 0.81	$ 0.60[1]	$ 0.95[1]	$ 0.78[1]

[1] Mid-point of guidance.

3. *Depreciation and Amortization.* We forecast depreciation and amortization based on our existing depreciable assets, forecasted capital expenditures and projected in-service dates. Depreciation may vary during any one period due to gains and losses on intermittent sales of assets, asset retirement obligations, asset impairments or foreign exchange rates.

4. *Acquisitions and Other Capital Expenditures.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions to which we may commit after the date hereof. We forecast capital expenditures during calendar 2010 to be approximately $360 million for expansion projects with an additional $85 million for maintenance capital projects. During the first six months of 2010, we spent $163 million and $33 million, respectively, for expansion and maintenance projects. Following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2010:

	Calendar 2010 (in millions)
Expansion Capital	
PAA Natural Gas Storage	95
Patoka Phase III	18
West Texas gathering lines	18
Cushing Phase VII	17
Edmonton land purchase	16
St. James Phase III	15
Cushing Phase VIII	15
Wichita Falls tanks	11
Other projects[(1)]	155

	360
Maintenance Capital	85
Total Projected Capital Expenditures (excluding acquisitions)	445

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2009.

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5. *Capital Structure.* This guidance is based on our capital structure as of June 30, 2010, as adjusted to give effect to the issuance on July 14, 2010 of $400 million of 3.95% 5-year senior notes as well as the anticipated redemption in September of our $175 million 6.25% senior notes due 2015.

6. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, estimated capital expenditures for maintenance and expansion projects, expected timing of collections and payments, and forecasted levels of inventory and other working capital sources and uses. Interest rate assumptions for variable rate debt are based on the current forward LIBOR curve.

   Included in interest expense are commitment fees, amortization of long-term debt discounts or premiums, deferred amounts associated with terminated interest-rate hedges and interest on short-term debt for non-contango inventory (primarily hedged LPG inventory and New York Mercantile Exchange and IntercontinentalExchange margin deposits). Interest expense is net of amounts capitalized for major expansion capital projects and does not include interest on borrowings for inventory stored in a contango market. We treat interest on contango-related borrowings as carrying costs of crude oil and include it in purchases and related costs.

7. *Net Income per Unit.* Basic net income per limited partner unit is calculated by dividing net income allocated to limited partners by the basic weighted average units outstanding during the period.

	Actual	Guidance[1]					
	6 Months Ended 6/30/2010	3 Months Ending September 30, 2010		3 Months Ending December 31, 2010		12 Months Ending December 31, 2010	
		Low	High	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:							
Net Income attributable to Plains	$ 282	$ 92	$ 122	$ 134	$ 164	$ 508	$ 568
Less: General partners incentive distribution paid [(1)]	(77)	(40)	(40)	(42)	(42)	(159)	(1