PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
July 28, 2005

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) **July 28, 2005**

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

(c) Exhibit 99.1 Press Release dated July 28, 2005

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

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its second quarter 2005 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 updating certain aspects of our previous guidance for financial performance for the third quarter, fourth quarter and full year of calendar 2005. 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 Act of 1934, as amended, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Update of Third Quarter, Fourth Quarter and Full Year 2005 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 11 below, we reconcile EBITDA and EBIT to net income for the guidance periods presented. However, it is impractical to reconcile EBIT and EBITDA to cash flows from operating activities for forecasted periods. We also encourage you to visit our website at *www.paalp.com*, in particular the section entitled Non-GAAP Reconciliation, which presents a historical reconciliation of certain commonly used non-GAAP financial measures, including EBIT and EBITDA. 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 on EBITDA, Net Income and Net Income per Limited Partner Unit of our long-term incentive program, revaluations of foreign currency and, to the extent known, gains and losses related to SFAS 133 (primarily non-cash, mark-to-market adjustments).

The following guidance for the three months ending September 30, and December 31, 2005 and the twelve months ending December 31, 2005 is based on assumptions and estimates that we believe are reasonable given our assessment of historical trends, business cycles and other information reasonably available. However, our assumptions and future performance 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 the 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 July 27, 2005. We undertake no obligation to publicly update or revise any forward-looking statements.

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

	Actual Six Months Ended June 30, 2005	Guidance(1) Three Months Ended September 30, 2005 Low	High	December 31, 2005 Low	High	Twelve Months Ended December 31, 2005 Low	High
Pipeline							
Net revenues	$ 188.2	$ 93.5	$ 95.5	$ 94.0	$ 97.5	$ 375.7	$ 381.2
Field operating costs	(72.1)	(36.7)	(35.5)	(36.0)	(35.0)	(144.8)	(142.6)
General and administrative expenses	(24.6)	(14.0)	(13.5)	(13.9)	(13.4)	(52.5)	(51.5)
	91.5	42.8	46.5	44.1	49.1	178.4	187.1
Gathering, Marketing, Terminalling & Storage							
Net revenues	153.1	89.0	94.0	67.4	75.9	309.5	323.0
Field operating costs	(59.5)	(31.0)	(30.2)	(30.6)	(29.6)	(121.1)	(119.3)
General and administrative expenses	(23.6)	(13.0)	(12.5)	(13.1)	(12.6)	(49.7)	(48.7)
	70.0	45.0	51.3	23.7	33.7	138.7	155.0
Segment Profit	161.5	87.8	97.8	67.8	82.8	317.1	342.1
Depreciation and amortization expense	(38.6)	(20.3)	(19.8)	(20.8)	(20.3)	(79.7)	(78.7)
Interest expense	(28.8)	(16.8)	(16.2)	(17.0)	(16.6)	(62.6)	(61.6)
Other Income (Expense)	1.0					1.0	1.0
Net Income	**$ 95.1**	**$ 50.7**	**$ 61.8**	**$ 30.0**	**$ 45.9**	**$ 175.8**	**$ 202.8**
Net Income to Limited Partners (see Note 9)	$ 86.9	$ 46.0	$ 56.9	$ 25.7	$ 41.3	$ 158.6	$ 185.0
Basic:							
Weighted Average Units Outstanding	67.7	67.9	67.9	67.9	67.9	67.8	67.8
Net Income Per Limited Partner Unit (see Note 9)	$ 1.27	$ 0.67	$ 0.75	$ 0.38	$ 0.61	$ 2.34	$ 2.69
Diluted:							
Weighted Average Units Outstanding	68.7	69.5	69.5	69.5	69.5	69.1	69.1
Net Income Per Limited Partner Unit (see Note 9)	$ 1.26	$ 0.66	$ 0.74	$ 0.37	$ 0.59	$ 2.30	$ 2.64
EBIT	**$ 123.9**	**$ 67.5**	**$ 78.0**	**$ 47.0**	**$ 62.5**	**$ 238.4**	**$ 264.4**
EBITDA	**$ 162.5**	**$ 87.8**	**$ 97.8**	**$ 67.8**	**$ 82.8**	**$ 318.1**	**$ 343.1**
Selected Items Impacting Comparability							
LTIP charge	$ (10.2)	$ (7.2)	$ (7.2)	$ (7.2)	$ (7.2)	$ (24.5)	$ (24.5)
SFAS 133 non-cash mark-to-market adjustment	(26.3)					(26.3)	(26.3)
FX gain (loss)	0.2					0.2	0.2
	$ (36.3)	$ (7.2)	$ (7.2)	$ (7.2)	$ (7.2)	$ (50.6)	$ (50.6)
Excluding Selected Items Impacting Comparability							
Adjusted EBITDA	$ 198.7	$ 95.0	$ 105.0	$ 75.0	$ 90.0	$ 368.7	$ 393.7
Adjusted Net Income	$ 131.3	$ 57.9	$ 69.0	$ 37.2	$ 53.1	$ 226.4	$ 253.4
Adjusted Basic Net Income per Limited Partner Unit	$ 1.81	$ 0.78	$ 0.94	$ 0.48	$ 0.71	$ 3.07	$ 3.46
Adjusted Diluted Net Income per Limited Partner Unit	$ 1.78	$ 0.76	$ 0.92	$ 0.47	$ 0.70	$ 3.01	$ 3.40

---

(1) The projected average foreign exchange rate is $1.25 CAD to $1 USD.

3

Notes and Significant Assumptions:

1. *Definitions.*

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Bbl/d	Barrels per day
Segment Profit	Net revenues less purchases, field operating costs, and segment general and administrative expenses
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other petroleum products
FX	Foreign currency exchange
GMT&S	Gathering, Marketing, Terminalling & Storage

2. *Pipeline Operations.* Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of organic growth projects. Volumes are influenced by temporary market-driven storage and withdrawal of oil, end-user refinery maintenance schedules, field declines and other external factors beyond our control. Actual segment profit could vary materially depending on the level of volumes transported. The following table summarizes our pipeline volumes and breaks out the major systems that are significant either in total volumes transported or in contribution to total net revenue.

	Calendar 2005 Actual Six Months Ended June 30	**Guidance Three Months Ended September 30**	**December 31**	**Twelve Months Ended December 31**
Average Daily Volumes (000 s Bbl/d)				
All American	52	51	51	51
Basin	280	285	270	279
Capline	152	165	140	153
Cushing to Broome(4)	54	85	80	68
West Texas / New Mexico area systems(1)	406	380	380	393
Other	565	739	729	651
	1,509	1,705	1,650	1,595
Canada(2)	258	270	270	264
	1,767	1,975	1,920	1,859
Segment Profit ($/Bbl)				
As Reported/Estimated	$ 0.286	$ 0.246 (3)	$ 0.264 (3)	$ 0.269 (3)
Excluding Selected Items Impacting Comparability	$ 0.304	$ 0.268 (3)	$ 0.286 (3)	$ 0.289 (3)

(1) The aggregate of 10 systems in the West Texas / New Mexico area.

(2) The aggregate of 8 systems.

(3) Mid-point of estimate.

(4) System became operational on March 1, 2005.

Segment profit is forecasted using the volume assumptions in the table above priced at tariff rates currently received, with adjustments where appropriate for estimated escalation in certain rates as allowed by contractual terms, less estimated field operating costs and G&A. Field operating costs do not include depreciation. Effective July 1, 2005, common carrier tariffs are permitted to escalate approximately 3.6% in accordance with FERC regulated guidelines. However, in certain instances, contractual arrangements or market forces may not allow us to realize the benefit of these permitted

escalations. To illustrate the impact volume changes may have on segment profit, the following table provides a volume sensitivity analysis of three systems representing approximately 30% of total pipeline net revenues.

Volume Sensitivity Analysis

System	**Change in Volume (Bbls/d)**	**% of System Total**	**Change in Annualized Segment Profit (in millions)**
All American	5,000	10 %	$ 3.2
Basin	20,000	7 %	$ 1.8
Capline	10,000	7 %	$ 1.5

3. *Gathering, Marketing, Terminalling and Storage Operations*. The degree of volatility in the crude oil market influences the level of profit in the GMT&S segment. Our guidance for the second half of the year assumes that the favorable market conditions in the oil markets will subside over the remainder of the year.

LPG volumes are influenced by seasonal demands with higher volumes sold in the winter months, primarily for heating, and decreasing during the summer months.

	Calendar 2005 Actual	**Guidance**		
	Six Months Ended	**Three Months Ended**		**Twelve Months Ended**
	June 30	**September 30**	**December 31**	**December 31**
Average Daily Volumes (000 s Bbl/d)				
Crude Oil Lease Gathered	625	630	635	629
LPG	55	40	75	56
	680	670	710	685
Segment Profit ($/Bbl)				
As Reported/Estimated	$ 0.568	$ 0.781 (1)	$ 0.439 (1)	$ 0.587 (1)
Excluding Selected Items Impacting Comparability	$ 0.817	$ 0.832 (1)	$ 0.488 (1)	$ 0.734 (1)

(1) Mid-point of estimate.

Segment profit is forecasted using the volume assumptions stated above and estimates of unit margins, field operating costs, G&A and carrying costs for contango inventory based on current and anticipated market conditions. 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. Based on our mid-point projected segment profit per barrel for the third quarter of 2005, a 15,000 Bbl/d variance in lease gathering volumes would impact segment profit by approximately $4.2 million on an annualized basis. A $0.01 variance in the aggregate average per-barrel margin would impact segment profit by approximately $2.5 million on an annualized basis.

4. *Depreciation & Amortization.* Depreciation and amortization is forecast based on our existing depreciable assets and forecasted capital expenditures. Depreciation is computed using the straight-line method over estimated useful lives, which range from 3 years (for office property and equipment) to 50 years (for certain pipelines, crude oil terminals and facilities).

5. *Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging* Activities *(SFAS 133).* The guidance presented above does not include assumptions or

5

projections with respect to potential gains or losses related to derivatives accounted for under SFAS 133, as there is no accurate way to forecast these potential gains or losses. The potential gains or losses related to these derivatives (primarily non-cash, mark-to-market adjustments) could cause actual net income to differ materially from our projections.

6. *Acquisitions and Capital Expenditures.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any assumptions or forecasts for any material acquisition that may be made after the date hereof. Capital expenditures for expansion projects are forecast to be approximately $190 million during calendar 2005. Following are some of the more notable projects to be undertaken in 2005 and the estimated expenditures for the year.

	Calendar 2005 (In Millions)
• St. James, Louisiana storage facility	$ 21
• Trenton pipeline expansion	$ 34
• Capital projects associated with the Link acquisition	$ 18
• NW Alberta fractionator	$ 16
• Cushing Phase V expansion	$ 13
• Kerrobert Tank expansion	$ 9
• Shell South Louisiana Asset Acquisition	$ 8

During the six months ended June 30, 2005, approximately $73 million of the forecasted $190 million of expansion capital was incurred in accordance with the project commitments.

Capital expenditures for maintenance projects are forecast to be approximately $19 million during 2005, of which approximately $8 million was incurred in the first six months.

7. *Capital Structure.* The guidance is based on our capital structure as of June 30, 2005.

8. *Interest Expense.* Debt balances are projected based on estimated cash flows, current distribution rates, capital expenditures for maintenance and expansion projects, expected timing of collections and payments, and forecast levels of inventory and other working capital sources and uses.

Calendar 2005 interest expense is expected to be between $62.6 million and $61.6 million, assuming an average long-term debt balance of approximately $1.0 billion and an all-in average rate of approximately 6.3%. Included in the effective cost of debt are not only current cash payments, but also commitment fees, amortization of long-term debt discounts, and deferred amounts associated with terminated interest rate hedges. While interest on floating rate debt is based on a forward one-year LIBOR index curve of approximately 4.1%, over 90% of our projected average long-term debt balance has an average fixed interest rate of 6.0%. The amortization of deferred amounts associated with terminated interest rate hedges results in a non-cash component to interest expense of approximately $1.6 million per year (approximately $400,000 per quarter). Approximately 70% of the non-cash interest expense amounts will be completely amortized by the fourth quarter of 2006. The remainder will be amortized over the next eleven years.

Interest expense does not include interest on borrowings for contango inventory. We treat these costs as carrying costs of the crude and reflect it as part of the purchase price of the crude.

Long-term debt at December 31, 2005 is projected to be approximately $1.02 billion.

9. *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. Under *Emerging Issues Task Force Issue 03-06: Participating Securities and the Two-Class Method under FASB Statement No. 128* (EITF 03-06), when the Partnership s aggregate net income exceeds the aggregate distribution made during such period, earnings per limited partner unit are calculated as if all of the earnings for the period were distributed, regardless of the pro forma nature of the allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. Although EITF 03-06 does not impact overall net income or other financial results of the Partnership, for periods in which aggregate net income exceeds the aggregate distributions for such period, earnings per limited partner unit will be reduced. The following table reconciles net income to limited partners both before and after EITF 03-06.

	Guidance (in millions) **Three Months Ended September 30, 2005**		**Three Months Ended December 31, 2005**		**Twelve Months Ended December 31, 2005**	
	Low	**High**	**Low**	**High**	**Low**	**High**
Net Income	$ 50.7	$ 61.8	$ 30.0	$ 45.9	$ 175.8	$ 202.8
Less:						
General partners incentive distribution paid	(3.8)	(3.8)	(3.8)	(3.8)	(14.0)	(14.0)
	46.9	58.0	26.2	42.1	161.8	188.8
General partner 2% ownership	(0.9)	(1.1)	(0.5)	(0.8)	(3.2)	(3.8)
Net income available to limited partners	46.0	56.9	25.7	41.3	158.6	185.0
Pro forma additional general partner's incentive distribution	(0.4)	(5.7)	-	-	-	(2.8)
Numerator for basic and diluted earnings per limited partner unit						
Net Income available for limited partners under EITF 03-06	$ 45.6	$ 51.2	$ 25.7	$ 41.3	$ 158.6	$ 182.2
Denominator:						
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	67.9	67.9	67.9	67.9	67.8	67.8
Effect of dilutive securities:						
Weighted average 2005 LTIP units	1.6	1.6	1.6	1.6	1.3	1.3
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	69.5	69.5	69.5	69.5	69.1	69.1
Basic net income per limited partner unit	$ 0.67	$ 0.75	$ 0.38	$ 0.61	$ 2.34	$ 2.69
Diluted net income per limited partner unit	$ 0.66	$ 0.74	$ 0.37	$ 0.59	$ 2.30	$ 2.64

Net income allocated to limited partners is impacted by the income allocated to the general partner and the amount of the incentive distribution paid to the general partner. Accordingly, when the aggregate distribution is greater than net income, for each $0.05 per unit annual increase in the distribution rate up to $2.70 per unit, net income available for limited partners decreases approximately $1.1 million ($0.02 per unit) on an annualized basis. The amount of income allocated to our limited partnership interests is 98% of the total partnership income after deducting the amount of the general partner s incentive distribution. Based on our current annualized distribution rate of $2.60 per unit, our general partner s distribution is forecast to be approximately $18.7 million annually, of which $15.1 million is attributed to the incentive distribution rights. The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units.

10. *Long-term Incentive Plans*. The majority of phantom unit grants outstanding under our 1998 and 2005 Long-Term Incentive Plans contain vesting criteria that are based on a combination of performance benchmarks and service period. The phantom units under the 2005 plan generally vest on the later of 2 years, 4 years or 5 years, or achievement of annualized distribution levels of $2.60, $2.80 and $3.00 per unit, respectively, and the majority of the phantom units have a final service period vesting in 2011. Accordingly, guidance includes (i) for phantom units tied to the $2.60 and $2.80 performance levels, an accrual over the corresponding service period, as it has been deemed probable that the $2.80 performance level will be reached, and (ii) for the phantom units that vest when the $3.00 performance threshold is achieved but have a final service period vesting in 2011, a pro rata accrual associated with a six-year service period. For 2005, the guidance includes approximately $24.5 million of principally non-cash expense associated with these phantom units. The actual amount of LTIP expense amortization in any given year will be directly influenced by fluctuations in our unit price and the amount of amortization in the early years and will also be increased if a determination is made that achievement of any of the remaining performance thresholds is probable.

11. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the guidance ranges for EBIT and EBITDA to net income.

	Guidance (in millions) Three Months Ended September 30, 2005		**Three Months Ended December 31, 2005**		**Twelve Months Ended December 31, 2005**	
	Low	**High**	**Low**	**High**	**Low**	**High**
Reconciliation to Net Income						
EBITDA	$ 87.8	$ 97.8	$ 67.8	$ 82.8	$ 318.1	$343.1
Depreciation and amortization	20.3	19.8	20.8	20.3	79.7	78.7
EBIT	67.5	78.0	47.0	62.5	238.4	264.4
Interest expense	16.8	16.2	17.0	16.6	62.6	61.6
Net Income	$ 50.7	$ 61.8	$30.0	$45.9	$ 175.8	$202.8

8

Forward-Looking Statements and Associated Risks

All statements, other than statements of historical fact, included in this report are forward-looking statements, including, but not limited to, statements identified by the words anticipate, believe, estimate, expect, plan, intend and forecast and similar expressions and statemen regarding our business strategy, plans and objectives of our management for future operations. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- abrupt or severe production declines or production interruptions in outer continental shelf production located offshore California and transported on our pipeline system;
- the success of our risk management activities;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;
- successful integration and future performance of acquired assets or businesses;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counter-parties;
- declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- successful third-party drilling efforts in areas in which we operate pipelines or gather crude oil;
- demand for various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;
- fluctuations in refinery capacity in areas supplied by our transmission lines;
- the effects of competition;
- continued creditworthiness of, and performance by, our counterparties;
- the impact of crude oil price fluctuations;
- the impact of current and future laws, rulings and governmental regulations;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- the currency exchange rate of the Canadian dollar;

8

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our LTIP plan;
- general economic, market or business conditions; and
- other factors and uncertainties inherent in the marketing, transportation, terminalling, gathering and storage of crude oil and liquified petroleum gas.

We undertake no obligation to publicly update or revise any forward-looking statements. Further information on risks and uncertainties is available in our filings with the Securities and Exchange Commission, which information is incorporated by reference herein.

9

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 hereunto duly authorized.

	PLAINS ALL AMERICAN PIPELINE, L.P.		
	By:	PLAINS AAP, L. P., its general partner	
	By:	PLAINS ALL AMERICAN GP LLC, its general partner	
Date: July 28, 2005	By:	/s/ PHIL KRAMER	
		Name:	Phil Kramer
		Title:	*Executive Vice President and Chief Financial Officer*

10