

PLAINS ALL AMERICAN PIPELINE LP

Form 8-K

February 13, 2008

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) February 13, 2008

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE

(State or other jurisdiction of
incorporation)

1-14569

(Commission File
Number)

76-0582150

(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:

- Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
 - Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
 - Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
 - 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 February 13, 2008

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 fourth quarter and annual 2007 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 first quarter and full year of calendar 2008. 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, 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.

Disclosure of First Quarter and Full Year 2008 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 10 below, we reconcile EBITDA and EBIT to net income for the 2008 guidance periods presented. It is, however, impractical to reconcile EBIT and EBITDA to cash flows from operating activities for forecasted periods. 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 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 of our equity compensation plans on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three-month period ending March 31, 2008 and twelve-month period ending December 31, 2008, is based on assumptions and estimates that we believe are reasonable given our assessment of historical trends (modified for recent changes in market conditions), business cycles and other information reasonably available. 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 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 February 13, 2008. 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)

	Guidance ¹			
	3 Months Ending March 31, 2008		12 Months Ending December 31, 2008	
	Low	High	Low	High
Segment Profit				
Net revenues (including equity earnings from unconsolidated entities)	\$ 358	\$ 372	\$ 1,476	\$ 1,511
Field operating costs	(146)	(142)	(578)	(568)
General and administrative expenses	(46)	(44)	(172)	(167)
	166	186	726	776
Depreciation and amortization expense	(47)	(45)	(192)	(186)
Interest expense, net	(42)	(40)	(175)	(168)
Income tax expense	(1)	(1)	(3)	(3)
Other income (expense), net				
Net Income	\$ 76	\$ 100	\$ 356	\$ 419
Net Income to Limited Partners	\$ 51	\$ 75	\$ 257	\$ 319
Basic Net Income Per Limited Partner Unit				
Weighted Average Units Outstanding	116	116	116	116
Net Income Per Unit	\$ 0.44	\$ 0.65	\$ 2.21	\$ 2.75
Diluted Net Income Per Limited Partner Unit				
Weighted Average Units Outstanding	117	117	117	117
Net Income Per Unit	\$ 0.44	\$ 0.64	\$ 2.20	\$ 2.73
EBIT	\$ 119	\$ 141	\$ 534	\$ 590
EBITDA	\$ 166	\$ 186	\$ 726	\$ 776
Selected Items Impacting Comparability				
Equity compensation charge	\$ (9)	\$ (9)	\$ (34)	\$ (34)
Excluding Selected Items Impacting Comparability				
Adjusted Segment Profit				
Transportation	\$ 87	\$ 92	\$ 374	\$ 387
Facilities	31	34	146	153

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Marketing	57	69	240	270
Adjusted EBITDA	\$ 175	\$ 195	\$ 760	\$ 810
Adjusted Net Income	\$ 85	\$ 109	\$ 390	\$ 453
Adjusted Basic Net Income per Limited Partner Unit	\$ 0.52	\$ 0.73	\$ 2.50	\$ 3.03
Adjusted Diluted Net Income per Limited Partner Unit	\$ 0.52	\$ 0.72	\$ 2.48	\$ 3.01

(1) The projected average foreign exchange rate is \$1 CAD to \$1 USD. The rate as of February 12, 2008 was \$1.00 CAD to \$1 USD.

Notes and Significant Assumptions:

1. *Definitions.*

Bcf	Billion cubic feet
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Bbls/d	Barrels per day
Segment Profit	Net revenues (including equity earnings, as applicable) less purchases, field operating costs, and segment general and administrative expenses
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other natural gas related petroleum products
FX	Foreign currency exchange
General partner	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. *Business Segments.* We manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. 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. We also include in this segment our equity earnings from our investments in the Butte and Frontier pipeline systems, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Volumes are influenced by temporary market-driven storage and withdrawal of oil, maintenance schedules at refineries, production declines and other external factors beyond our control. Segment profit is forecast 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 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.

	2008 Guidance	
	Three Months Ending March 31	Twelve Months Ending December 31
Average Daily Volumes (000 Bbls/d)		
All American Basin	48	48
Capline / Capwood	360	360
Line 63 / 2000	350	350
Salt Lake City Area Systems ⁽¹⁾	175	175
West Texas / New Mexico Area Systems ⁽¹⁾	105	120
Manito	380	380
Rangeland	75	75
Refined Products	55	55
Other	110	110
	1,067	1,067
	2,725	2,740
Trucking	105	110
	2,830	2,850
Average Segment Profit (\$/Bbl)		
Excluding Selected Items Impacting Comparability	\$ 0.35 ⁽²⁾	\$ 0.36 ⁽²⁾

(1) The aggregate of multiple systems in the respective areas.

(2) 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 and LPG, 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. This segment also includes our equity earnings from our 50% investment in PAA/Vulcan Gas Storage, LLC which owns and operates approximately 25.7 billion cubic feet of underground natural gas storage capacity and is constructing an additional 24 Bcf of underground storage capacity.

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.

2008 Guidance	
Three Months	Twelve Months

	Ending March 31	Ending December 31
Operating Data		
Crude oil, refined products and LPG storage (MMBbls/Mo.)	46	50
Natural Gas Storage (Bcf/Mo.)	13	14
LPG Processing (MBbl/d)	16	19
Facilities Activities Total ¹		
Avg. Capacity (MMBbls/Mo.)	49	53
Segment Profit per Barrel (\$/Bbl)		
Excluding Selected Items Impacting Comparability	\$ 0.22 ₍₂₎	\$ 0.23 ₍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 crude oil barrel ratio; and
(iii) LPG processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly capacity in millions.

(2) Mid-point of guidance.

- c. *Marketing.* Our marketing segment operations generally consist of the following merchant activities:
- the purchase of U.S. and Canadian 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
 - arranging for 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 marketing 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 March 31, 2008 reflect our expectation of a backwardated market structure and weather-related seasonal variations in LPG sales. Unexpected changes in market structure or volatility (or lack thereof) could cause actual results to differ materially from forecasted results.

We forecast 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. 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.

	2008 Guidance	
	Three Months Ending March 31	Twelve Months Ending December 31
Average Daily Volumes (MBbl/d)		
Crude Oil Lease Gathering	690	685
LPG Sales	135	105
Refined Products	20	30
Waterborne foreign crude imported	75	75
	920	895
Segment Profit per Barrel (\$/Bbl)		
Excluding Selected Items Impacting Comparability	\$ 0.75 ₍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 is computed using the straight-line method over estimated useful lives, which range from 3 years (for office furniture and equipment) to 40 years (for certain pipelines, crude oil terminals and facilities) and includes gains and losses on the sale of assets.

4. *Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS 133)*. The guidance presented above does not include assumptions or 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 mark-to-market adjustments) could cause actual net income to differ materially from our projections.

5. *Capital Expenditures and Acquisitions.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions that may be made after the date hereof. Capital expenditures for expansion projects are forecasted to be approximately \$330 million during calendar 2008. Following are some of the more notable projects and forecasted expenditures for the year:

	Calendar 2008 (in millions)
Expansion Capital	
Patoka tankage	\$ 43
Kerrobert facility	36
Paulsboro tankage	30
Fort Laramie Tank Expansion	22
West Hynes tankage	13
Edmonton tankage and connections	12
Bumstead expansion	10
Pier 400(1)	10
Other Projects(2)	154
	330
Maintenance Capital	60
Total Projected Capital Expenditures (excluding acquisitions)	\$ 390

(1) This project requires approval from a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time.

(2) Primarily pipeline connections, upgrades and truck stations as

well as new tank
construction and
refurbishing.

6. *Capital Structure.* This guidance is based on our capital structure as of December 31, 2007. The Partnership's policy is to finance acquisitions and major growth capital projects with at least 50% equity or cash flow in excess of distributions. As a result of our equity financing activities in 2007 combined with our projected 2008 cash flows in excess of distributions, we have substantially pre-funded all of the required equity financing associated with our 2008 expansion capital program.
7. *Interest Expense.* Debt balances are projected based on estimated cash flows, current distribution rates, forecasted 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.

Annual 2008 interest expense is expected to be between \$168 million and \$175 million, assuming an average long-term debt balance of approximately \$2.8 billion during the period. 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 contango inventory. We treat interest on contango-related borrowings as carrying costs of crude oil and include it as part of the purchase price of crude oil.

8. *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.

	Guidance (in millions, except per unit data)			
	Three Months Ending March 31, 2008		Twelve Months Ending December 31, 2008	
	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:				
Net Income	\$ 76	\$ 100	\$ 356	\$ 419
General partners incentive distribution	(27)	(27)	(109)	(109)
General partners incentive distribution reduction	4	4	15	15
	53	77	262	325
General partner 2% ownership	(2)	(2)	(5)	(6)
Net income available to limited partners	\$ 51	\$ 75	\$ 257	\$ 319
Denominator:				
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	116	116	116	116
Effect of dilutive securities:				
Weighted average LTIP units	1	1	1	1
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	117	117	117	117
Basic net income per limited partner unit	\$ 0.44	\$ 0.65	\$ 2.21	\$ 2.75
Diluted net income per limited partner unit	\$ 0.44	\$ 0.64	\$ 2.20	\$ 2.73

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. The amount of income allocated to our limited partner 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 \$3.40 per unit, our general partner's distribution is forecast to be approximately \$117 million annually, of which approximately \$109 million is attributed to the incentive distribution rights. In conjunction with the Pacific acquisition, however, the general partner agreed to reduce the amounts due it as incentive distributions. The reduction will be effective for five years, as follows: (i) \$5 million per quarter for the first four quarters beginning with the February 2007 distribution, (ii) \$3.75 million per quarter for the following eight quarters, (iii) \$2.5 million per quarter for the following four quarters, and (iv) \$1.25 million per quarter for the final four quarters. The aggregate reduction in incentive distributions will be \$65 million and the total reduction during 2008 will be \$15 million. The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units. Based on the current number of units outstanding, each \$0.05 per unit annual increase in the distribution over \$3.40 per unit decreases net income available for limited partners by approximately \$6 million (\$0.05 per unit) on an annualized basis.

9.

Equity Compensation Plans. The majority of grants outstanding under our equity compensation plans (LTIP and Class B units) contain vesting criteria that are based on a combination of performance benchmarks and service period. The grants will vest in various percentages, typically on the later to occur of specified earliest vesting dates and the dates on which minimum distribution levels are reached. Among the various grants, vesting dates range from May 2008 to May 2012 and minimum annualized distribution levels range from \$2.80 to \$4.50. For some awards, a percentage of any remaining units will vest on a date certain in 2011 or 2012.

On January 16, 2008, we declared an annualized distribution of \$3.40 payable on February 14, 2008 to our unitholders of record as of February 4, 2008. In addition to achieving the distribution level of \$3.40, we have deemed probable that the \$3.50 distribution level will be achieved. Accordingly, for grants that vest at annualized distribution levels of \$3.50 or less, guidance includes an accrual over the applicable service period at an assumed market price of

\$52.00 per unit as well as the fair value associated with awards that will vest on a date certain. For 2008, the guidance includes approximately \$39 million of expense associated with these equity compensation plans. The actual amount of equity compensation expense amortization in any given year will be directly influenced by (i) our unit price at the end of each reporting period, (ii) our unit price on the date of actual vesting, (iii) the amount of amortization in the early years, (iv) the probability assessment of achieving future distribution rates, and (v) new equity compensation award grants. For example, a \$3.00 change in the unit price assumption at March 31, 2008 would change the first quarter equity compensation expense by \$3 million \$1 million for the current quarter and \$2 million for the life-to-date adjustment to the liability accrued in prior periods. Therefore, actual net income could differ materially from our projections.

Included in equity compensation expense highlighted in selected items impacting comparability for 2008 is approximately \$8 million of expense attributable to the Class B units. Since the economic burden of the Class B units is borne solely by the General Partner and not the Partnership, the expense will be reflected as a capital contribution and thus will result in a corresponding credit to Partners' Capital in the financial statements of the Partnership.

The amount of equity compensation expense highlighted in selected items impacting comparability for 2008 excludes the portion of the expense represented by awards that pursuant to their terms, will be settled in cash only (\$5 million) and have no impact in the determination of diluted units.

10. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the 2008 guidance ranges for EBITDA and EBIT to net income.

	Three Months Ending March 31, 2008		Twelve Months Ending December 31, 2008	
	Low	High	Low	High
	(in millions)		(in millions)	
Reconciliation to Net Income				
EBITDA	\$ 166	\$ 186	\$ 726	\$ 776
Depreciation and amortization	47	45	192	186
EBIT	119	141	534	590
Interest expense	42	40	175	168
Income tax expense	1	1	3	3
Net Income	\$ 76	\$ 100	\$ 356	\$ 419

Forward-Looking Statements and Associated Risks

All statements included in this report, other than statements of historical fact, are forward-looking statements, including, but not limited to, statements identified by the words anticipate, believe, estimate, expect, plan, forecast and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. 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:

failure to implement or capitalize on planned internal growth projects;

the success of our risk management activities;

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 counterparties;

abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;

shortages or cost increases of power supplies, materials or labor;

the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate, and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers;

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 transmission throughput requirements;

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 and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

unanticipated changes in crude oil market structure and volatility (or lack thereof);

the impact of current and future laws, rulings and governmental regulations;

the effects of competition;

continued creditworthiness of, and performance by, our counterparties;

interruptions in service and fluctuations in tariffs or volumes 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;