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)—November 5, 2008

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) Exhibits
Exhibit 99.1 – Press Release dated November 5, 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 third-quarter 2008 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 updated detailed guidance for financial performance for the fourth quarter of calendar 2008 and resulting financial performance for the full year of calendar year of 2008 (which supersedes guidance pertaining to 2008 contained in our Form 8-K furnished on August 6, 2008). 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.

Update of Fourth Quarter 2008 Guidance; Comments on 2009 Preliminary Guidance Initially Furnished on Form 8-K on May 29, 2008

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 12 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 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 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, revaluations of foreign currency, inventory valuation adjustments and, to the extent known, gains and losses related to SFAS 133 (primarily non-cash, mark-to-market adjustments) on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three months and twelve months ending December 31, 2008 is based 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 information reasonably available. 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 November 4, 2008. We undertake no obligation to publicly update or revise any forward-looking statements.

	Actual	Guidance (1)			
	9 Months Ended 09/30/08	3 Months Ending December 31, 2008		12 Months Ending December 31, 2008	
		Low	High	Low	High
Segment Profit					
Net revenues (including equity earnings from unconsolidated entities)	$ 1,200	$ 416	$ 430	$ 1,616	$ 1,630
Field operating costs	(458)	(159)	(155)	(617)	(613)
General and administrative expenses	(130)	(41)	(39)	(171)	(169)
	612	216	236	828	848
Depreciation and amortization expense	(150)	(54)	(53)	(204)	(203)
Interest expense, net	(143)	(55)	(53)	(198)	(196)
Income tax expense	(7)	(4)	(4)	(11)	(11)
Other income (expense), net	27	2	2	29	29
Net Income	**$ 339**	**$ 105**	**$ 128**	**$ 444**	**$ 467**
Net Income to Limited Partners	$ 256	$ 75	$ 98	$ 331	$ 354
Basic Net Income Per Limited Partner Unit					
Weighted Average Units Outstanding	120	123	123	120	120
Net Income Per Unit	$ 2.14	$ 0.61	$ 0.80	$ 2.76	$ 2.95
Diluted Net Income Per Limited Partner Unit					
Weighted Average Units Outstanding	121	124	124	121	121
Net Income Per Unit	$ 2.12	$ 0.60	$ 0.79	$ 2.74	$ 2.93
EBIT	**$ 489**	**$ 164**	**$ 185**	**$ 653**	**$ 674**
EBITDA	**$ 639**	**$ 218**	**$ 238**	**$ 857**	**$ 877**

Selected Items Impacting Comparability					
SFAS 133 Mark-to-Market Adjustment (see note 4)	$ 72	$ —	$ —	$ 72	$ 72
Gains on Rainbow acquisition-related hedges	11	—	—	11	11
Net loss on foreign currency revaluation (see note 5)	(8)	—	—	(8)	(8)
Equity compensation expense (see note 11)	(23)	(7)	(7)	(30)	(30)
Inventory valuation adjustment (see note 6)	(65)	—	—	(65)	(65)
	$ (13)	$ (7)	$ (7)	$ (20)	$ (20)

Excluding Selected Items Impacting Comparability					
Adjusted Segment Profit					
Transportation	$ 327	$ 118	$ 123	$ 445	$ 450
Facilities	111	42	45	153	156
Marketing	198	63	75	261	273
Other Income (Expense), net	16	2	2	18	18
Adjusted EBITDA	$ 652	$ 225	$ 245	$ 877	$ 897
Adjusted Net Income	$ 352	$ 112	$ 135	$ 464	$ 487
Adjusted Basic Net Income per Limited Partner Unit	$ 2.24	$ 0.67	$ 0.85	$ 2.93	$ 3.11
Adjusted Diluted Net Income per Limited Partner Unit	$ 2.22	$ 0.66	$ 0.85	$ 2.90	$ 3.08

(1) The projected average foreign exchange rate is $1.20 CAD to $1 USD. The rate as of November 4, 2008 was $1.15 CAD to $1 USD.

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
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, weather and other natural disasters including hurricanes, 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.

	Calendar 2008		
	Actual	Guidance	
	Nine Months Ended September 30	Three Months Ending December 31	Twelve Months Ending December 31
Average Daily Volumes (000 Bbls/d)			
All American	44	44	44
Basin	372	373	372
Capline	218	235	222
Line 63 / 2000	151	140	148
Salt Lake City Area Systems (1)	94	100	96
West Texas / New Mexico Area Systems (1)	367	370	368
Rainbow	108	195	130
Manito	70	70	70
Rangeland	58	55	57
Refined Products	110	115	111
Other	1,238	1,228	1,236
	2,830	2,925	2,854
Trucking	96	110	100
	2,926	3,035	2,954
Average Segment Profit ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.41	$ 0.43(2)	$ 0.41(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 26 Bcf 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.

	Calendar 2008		
	Actual	Guidance	
	Nine Months Ended September 30	Three Months Ending December 31	Twelve Months Ending December 31
Operating Data			
Crude oil, refined products and LPG storage (MMBbls/Mo.)(1)	54	56	55

Natural Gas Storage (Bcf/Mo.)	13	13	13
LPG Processing (MBbl/d)	16	18	17
Facilities Activities Total (2)			
Avg. Capacity (MMBbls/Mo.)	57	59	58
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.22	$ 0.25(3)	$ 0.22(3)

(1) Effective with the second quarter of 2008, facilities segment volumes with respect to crude oil and refined products are reported based on total shell capacity to provide uniform comparisons with respect to our activities for these products. Previously, such volumes were reported based on a combination of shell capacity and working capacity depending on the terms of the third-party or intra-company lease agreements. Natural gas and LPG volumes, which consist primarily of underground storage facilities, reflect working capacity as that is the primary basis upon which such facilities are leased. Corresponding metrics for prior periods have been conformed to this uniform approach.

(2) 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.

(3) 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
- 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 remainder of 2008 reflect (i) continued impacts related to Hurricanes Gustav and Ike, including an approximate 35,000 barrel per day decrease in crude oil lease gathering, (ii) adjustments relative to historical practices with respect to deployment of working capital for inventory carry opportunities, (iii) reduction of high-cost, lower margin volumes, and (iv) seasonal, weather-related variations in LPG sales. 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. Volumes are influenced by temporary market-driven storage and withdrawal of oil, maintenance schedules at refineries, production declines, weather and other natural disasters including hurricanes, 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.

	Calendar 2008		
	Actual	**Guidance**	
	Nine Months Ended September 30	**Three Months Ending December 31**	**Twelve Months Ending December 31**
Average Daily Volumes (MBbl/d)			
Crude Oil Lease Gathering	663	640	657
LPG Sales	85	110	91
Refined Products	24	28	25
Waterborne foreign crude imported	84	74	82
	856	852	855
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.84	$ 0.88(1)	$ 0.85(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 (SFAS) No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended ("SFAS 133").* This guidance 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. *Foreign Currency Revaluations.* PAA has certain Canadian subsidiaries that conduct business in a U.S. dollar currency (primarily butane operations). Under SFAS 52 “Foreign Currency Translation,” gains and losses from foreign currency transactions (monetary transactions denominated in a currency other than the entity's functional currency) are included in the consolidated statement of operations in other income. The recent significant strengthening of the U.S. dollar resulted in an $8 million loss in the third quarter of 2008. However, as we liquidate butane inventory over the remainder of 2008 and early 2009, we will recognize higher profit margins that will principally offset these losses. The timing of the liquidation of this inventory is difficult to predict, as such, guidance for adjusted EBITDA does not reflect the anticipated inventory sales and the potential non-cash gains or losses related to these foreign currency revaluations which could cause actual net income to differ materially from our projections.

6. *Inventory Revaluations.* In the third quarter of 2008, certain crude oil and LPG inventories were revalued to current market prices that resulted in a loss of approximately $65 million and were not included in adjusted EBITDA. Since the inventory was hedged with derivatives ensuring future sales prices, the third quarter loss is expected to be materially offset by a higher profit margin on inventory sales in later periods (principally fourth quarter 2008 and first half 2009), subject to normal hedge effectiveness. The timing of the liquidation of this inventory is difficult to predict as such, guidance for adjusted EBITDA does not reflect the anticipated hedged inventory sales and expected gains which could cause actual net income to differ materially from our projections.

7. *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 $470 million during calendar 2008, of which $379 million was spent in the first nine months of 2008. Following are some of the more notable projects and forecasted expenditures for the year:

	Calendar 2008 (in millions)
Expansion Capital	
• Patoka tankage	$ 54
• Paulsboro tankage	30
• Fort Laramie tank expansion	22
• St. James phase III (1)	22
• Kerrobert mainline connection	20
• Rangeland tankage and connections	14
• West Hynes tankage	13
• Pier 400 (2)	11
• Other projects, including acquisition related expansion projects (3)	284
	470
Maintenance Capital	75
Total Projected Capital Expenditures (excluding acquisitions)	$ 545

(1) Includes a dock and condensate tanks.

(2) 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. Does not include intangible expenditures of approximately $5 million for emission reduction credits.

(3) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2007.

Capital expenditures for maintenance projects are forecast to be approximately $75 million during 2008, of which $56 million was incurred in the first nine months.

8. *Capital Structure.* This guidance is based on our capital structure as of September 30, 2008.

9. *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.

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 Chicago 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 as part of the purchase price of crude oil.

10. *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.

	2008 Guidance (in millions)			
	Three Months Ending December 31		Twelve Months Ending December 31	
	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:				
Net Income	$ 105	$ 128	$ 444	$ 467
General partners incentive distribution	(34)	(34)	(124)	(124)
General partners incentive distribution reduction	6	6	18	18
	77	100	338	361
General partner 2% ownership	(2)	(2)	(7)	(7)
Net income available to limited partners	$ 75	$ 98	$ 331	$ 354
Denominator:				
Denominator for basic earnings per limited partner unit- weighted average number of limited partner units	123	123	120	120
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	124	124	121	121
Basic net income per limited partner unit	$ 0.61	$ 0.80	$ 2.76	$ 2.95
Diluted net income per limited partner unit	$ 0.60	$ 0.79	$ 2.74	$ 2.93

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 (less any hypothetical distributions to the general partner in accordance with EITF 03-06). 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 as adjusted for temporary reductions in the incentive distribution rights.

In conjunction with the Pacific and Rainbow acquisitions, the general partner reduced the amounts due it as incentive distributions by an aggregate amount of $75 million. Approximately $31.3 million of this reduction was realized as of August 14, 2008. Incentive distributions will be reduced by $6 million for the fourth quarter of 2008, $21 million in 2009, $11 million in 2010 and $5 million in 2011.

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 or decrease in the distribution relative to forecasted amounts decreases or increases, respectively, net income available for limited partners by approximately $6 million ($0.05 per unit) on an annualized basis.

11. *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 outstanding as of November 4, 2008, estimated vesting dates range from May 2009 to January 2016 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 and all others are forfeited.

On October 22, 2008, we declared an annualized distribution of $3.57 payable on November 14, 2008 to our unitholders of record as of November 4, 2008. In addition to the current distribution level of $3.57, we have deemed probable that the $3.75 distribution level will be achieved. Accordingly, for grants that vest at annualized distribution levels of $3.75 or less, guidance includes an accrual over the applicable service period at an assumed market price of $39.62 per unit as well as the fair value associated with awards that will vest on a date certain. The actual amount of equity compensation expense amortization in any given period 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 December 31, 2008 would change the fourth-quarter equity compensation expense by approximately $5 million — $1 million for the current quarter and $4 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 $15 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, an amount equal to 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.

12. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the three-month and twelve month guidance range ending December 31, 2008 for EBITDA and EBIT to net income.

	2008 Guidance (in millions)			
	Three Months Ending December 31		Twelve Months Ending December 31	
	Low	High	Low	High
Reconciliation to Net Income				
EBITDA	$ 218	$ 238	$ 857	$ 877

Depreciation and amortization	54	53	204	203
EBIT	164	185	653	674
Interest expense	55	53	198	196
Income tax expense	4	4	11	11
Net Income	$ 105	$ 128	$ 444	$ 467

Comments on Preliminary Calendar 2009 Guidance

On May 29, 2008, the partnership provided preliminary guidance for 2009 based on a foreign exchange (“FX”) rate of $1.00 CAD to $1.00 USD. The closing FX rate on May 28 was $0.99 CAD to $1.00 USD. The average FX rate during the first nine months of 2008 was $1.02 CAD to $1.00 USD. During October 2008, the CAD weakened significantly and the October 31 closing FX rate was $1.21 CAD to $1.00 USD. Within a given period, the actual economic impact of an adverse change in the FX rate is reduced or offset by a corresponding decrease in Canadian interest expense, taxes, repayment of third party Canadian dollar debt and capital reinvested within Canada. In addition, we have hedges in place for the amount of Canadian dollars we actually expect to return to the U.S. Accordingly the weakening of the Canadian dollar is not anticipated to have a material net economic effect in 2009.

Despite these offsetting factors and the minimal actual net economic impact, the amount of adjusted EBITDA we report will be influenced by changes in the FX rate. Based on an FX rate of $1.20 CAD to $1.00 USD, the detriment to the preliminary guidance for 2009 adjusted EBITDA furnished on May 29, 2008, would be approximately $30 milllion, net of hedges.

Looking beyond 2009, a positive or negative economic impact is realized if unhedged Canadian dollars are returned to the U.S., depending on the FX rate in effect at the time. The partnership has a substantial inventory of capital opportunities in Canada and has and will continue to actively manage the flow of capital between the two countries to optimize or mitigate as appropriate the economic impact on the partnership.

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,” “intend” and “forecast,” as well as 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;
- 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 success of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- 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, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;
- 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 successful integration and future performance of acquired assets and 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, governmental regulations and interpretations;
- the effects of competition;
- 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;
- risks related to the development and operation of natural gas storage facilities;
- future developments and circumstances at the time distributions are declared;
- general economic, market or business conditions; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

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.

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: PAA GP LLC, its general partner

By: PLAINS AAP, L. P., its sole member

By: PLAINS ALL AMERICAN GP LLC, its general partner

Date: November 5, 2008

By: /s/ AL SWANSON
Name: Al Swanson
Title: *Senior Vice President-Finance*

PLAINS ALL AMERICAN PIPELINE, L.P.

News Release

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FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P.
Reports Solid Third-Quarter 2008 Results

(Houston – November 5, 2008) Plains All American Pipeline, L.P. (NYSE: PAA) today reported net income of $206 million, or $1.14 per diluted limited partner unit, for the third quarter of 2008 as compared to net income for the third quarter of 2007 of $98 million, or $0.66 per diluted limited partner unit. The Partnership reported earnings before interest, taxes, depreciation and amortization ("EBITDA") of $310 million for the third quarter of 2008, compared with EBITDA of $183 million for the third quarter of 2007.

Reported results for the quarter ended September 30, 2008 were impacted by a larger than usual mark-to-market adjustment and an inventory valuation adjustment resulting from the significant decrease in crude oil and liquefied petroleum gas ("LPG") prices during the period. Reported results include the impact of these adjustments and various other items that affect comparability between reporting periods. These items are excluded from adjusted results, as further described in the table below. Accordingly, the Partnership's third-quarter 2008 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA were $119 million, $0.70 and $223 million, respectively. The Partnership's third-quarter 2007 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA were $111 million, $0.77 and $196 million, respectively. (See the section of this release entitled "Non-GAAP Financial Measures" and the attached tables for discussion of EBITDA and other non-GAAP financial measures, and reconciliations of such measures to the comparable GAAP measures.)

"Plains All American delivered third-quarter results that were in line with guidance during a period marked by operational challenges related to Hurricanes Gustav and Ike," stated Greg L. Armstrong, Chairman and CEO of Plains All American. "We continue to see strong demand for our assets and services within each of our three segments, and we are pleased with PAA's positioning relative to the current state of the financial markets. We have a solid balance sheet, ample liquidity and are well positioned to execute our growth plans for the remainder of 2008 and the full year of 2009 without the need to access the capital markets."

The Partnership's third-quarter results were also impacted by items that have not been included as selected items impacting comparability between reporting periods. These items primarily include an estimated $10 million to $15 million negative impact related to Hurricanes Gustav and Ike, and an approximate $12 million gain on the sale of its shares in the New York

– MORE –

Mercantile Exchange ("NYMEX") in connection with the NYMEX's August 2008 merger with the Chicago Mercantile Exchange. The hurricane impact includes an estimate of reduced revenues attributable to disruptions in crude transportation and marketing volumes, insurance deductibles associated with response and repair costs included in operating expenses and a $1 million contribution by the Partnership to a relief fund to assist employees sustaining hurricane damage.

For the first nine months of 2008, the Partnership reported net income of $339 million, or $2.12 per diluted limited partner unit, as compared to net income for the first nine months of 2007 of $288 million, or $2.05 per diluted limited partner unit. The Partnership reported EBITDA of $639 million for the first nine months of 2008, compared with EBITDA of $559 million for the first nine months of 2007. Adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA for the first nine months of 2008 were $352 million, $2.22 and $652 million, respectively. Adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA for the first nine months of 2007 were $352 million, $2.60 and $612 million, respectively.

The following table summarizes selected items that the Partnership believes impact comparability of financial results between reporting periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In millions, except per unit data)		(In millions, except per unit data)	
Selected items impacting comparability				
Equity compensation charge [1]	$ (3)	$ —	$ (23)	$ (38)
SFAS 133 mark-to-market adjustment [2]	163	(13)	72	(15)
Gains on Rainbow acquisition-related hedges	—	—	11	—
Inventory valuation adjustment	(65)	—	(65)	—
Net loss on foreign currency revaluation	(8)	—	(8)	—
Deferred income tax expense	—	—	—	(11)
Selected items impacting comparability	87	(13)	(13)	(64)

Less: GP 2% portion of selected items impacting comparability	(2)	—	—	1
LP 98% portion of selected items impacting comparability	$ 85	$ (13)	$ (13)	$ (63)
Impact to basic net income per limited partner unit [3]	$ 0.44	$ (0.11)	$ (0.10)	$ (0.56)
Impact to diluted net income per limited partner unit [3]	$ 0.44	$ (0.11)	$ (0.10)	$ (0.55)

(1) The equity compensation charge for the three- and nine-month periods ended September 30, 2008 and 2007 excludes the portion of the equity compensation expense represented by grants under the LTIP Plans that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans for the three- and nine-month periods of both years is approximately $1 million and $3 million, respectively.

(2) The Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended ("SFAS 133") gain for the three- and nine-month periods ended September 30, 2008 includes a gain of less than $1 million and a loss of less than $1 million, respectively, related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit. The SFAS 133 charge for both the three- and nine- month periods ended September 30, 2007 includes a $2 million gain related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit.

(3) Reflects pro forma full distribution of earnings under EITF 03-06. The application of EITF 03-06 negatively impacted basic earnings per limited partner unit and diluted earnings per limited partner unit by $0.26 and $0.25, respectively for the quarter ended September 30, 2008.

The Partnership indicated that its hedging activities conducted during the third quarter of 2008 were consistent with prior periods; however, the significant decreases in crude oil and LPG

prices resulted in an inventory valuation adjustment and a larger than usual SFAS 133 mark-to-market adjustment for the quarter ended September 30, 2008. The inventory subject to the valuation adjustment was hedged with financial derivatives and the inventory valuation charge is offset by the SFAS mark-to-market gain, subject to normal hedge effectiveness. The Partnership expects that the effect of these adjustments will reverse in future periods as the offsetting physical transactions are settled.

The following tables present certain selected financial information by segment for the third quarter and first nine months (amounts in millions):

	Three Months Ended September 30, 2008			Three Months Ended September 30, 2007		
	Transportation Operations	**Facilities Operations**	**Marketing Operations**	**Transportation Operations**	**Facilities Operations**	**Marketing Operations**
Revenues [1]	$ 242	$ 69	$ 8,676	$ 198	$ 54	$ 5,668
Purchases and related costs [1]	(23)	—	(8,471)	(20)	—	(5,556)
Field operating costs (excluding equity compensation charge)	(86)	(27)	(50)	(74)	(22)	(38)
Equity compensation benefit - operations	1	—	—	—	—	—
Segment G&A expenses (excluding equity compensation charge) [2]	(14)	(5)	(16)	(14)	(5)	(13)
Equity compensation charge - general and administrative	(2)	(1)	(1)	(1)	—	—
Equity earnings in unconsolidated entities	1	3	—	2	2	—
Reported segment profit	$ 119	$ 39	$ 138	$ 91	$ 29	$ 61
Selected items impacting comparability of segment profit [3]:						
Equity compensation charge [4]	1	1	1	—	—	—
SFAS 133 mark-to-market impact [5]	—	—	(163)	—	—	15
Inventory valuation adjustment	—	—	65	—	—	—
Net loss on foreign currency revaluation	—	—	8	—	—	—
Segment profit excluding selected items impacting comparability	$ 120	$ 40	$ 49	$ 91	$ 29	$ 76
Maintenance capital	$ 13	$ 5	$ 1	$ 9	$ —	$ 1

	Nine Months Ended September 30, 2008			Nine Months Ended September 30, 2007		
	Transportation Operations	**Facilities Operations**	**Marketing Operations**	**Transportation Operations**	**Facilities Operations**	**Marketing Operations**
Revenues [1]	$ 680	$ 194	$ 24,594	$ 571	$ 153	$ 13,565
Purchases and related costs [1]	(68)	—	(24,211)	(58)	—	(13,169)
Field operating costs (excluding equity compensation charge)	(246)	(76)	(135)	(213)	(62)	(115)
Equity compensation charge - operations	(1)	—	—	(5)	—	—
Segment G&A expenses (excluding equity compensation charge) [2]	(42)	(13)	(49)	(38)	(15)	(39)
Equity compensation charge - general and administrative	(12)	(5)	(9)	(16)	(5)	(15)
Equity earnings in unconsolidated entities	4	7	—	3	9	—
Reported segment profit	$ 315	$ 107	$ 190	$ 244	$ 80	$ 227
Selected items impacting comparability of segment profit [3]:						
Equity compensation charge [4]	12	4	7	19	5	14

SFAS 133 mark-to-market impact [5]	—	—	(72)	—	—	17
Inventory valuation adjustment	—	—	65	—	—	—
Net loss on foreign currency revaluation	—	—	8	—	—	—
Segment profit excluding selected items impacting comparability	$ 327	$ 111	$ 198	$ 263	$ 85	$ 258
Maintenance capital	$ 38	$ 15	$ 3	$ 22	$ 6	$ 4

(1) Includes intersegment amounts.
(2) Segment general and administrative expenses (G&A) reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.
(3) Excludes deferred income tax expense and the gains on Rainbow acquisition-related hedges as they do not impact segment profit.
(4) The equity compensation charge for the three- and nine-month periods ended September 30, 2008 and 2007 excludes the portion of the equity compensation expense represented by grants under the LTIP Plans that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans for the three- and nine-month periods of both years is approximately $1 million and $3 million, respectively.
(5) The SFAS 133 gain for the three- and nine-month periods ended September 30, 2008 includes a gain of less than $1 million and a loss of less than $1 million, respectively, related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit. The SFAS 133 charge for both the three- and nine-month periods ended September 30, 2007 includes a $2 million gain related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit.

– MORE –

Adjusted segment profit from Transportation operations for the third quarter of 2008 increased 32% over corresponding third-quarter 2007 results due principally to contributions from the Partnership’s Rainbow Pipe Line acquisition which occurred in May 2008, higher average tariffs and an increase in pipeline loss allowance revenue. These contributions were partially offset by higher operating expenses and an estimated $3 million to $5 million negative impact primarily due to lost revenues associated with hurricane-related volume reductions on certain of the Partnership’s Gulf Coast area pipelines.

Adjusted segment profit from Facilities operations for the third quarter of 2008 increased 38% over corresponding third-quarter 2007 results due primarily to an approximate 16% capacity increase associated with expansions at the Cushing, St. James, and Martinez facilities as well as the Tirzah & Bumstead LPG facility acquisitions.

Adjusted segment profit from Marketing operations for the third quarter of 2008 was $49 million, representing a decrease of 36% from corresponding third-quarter 2007 results of $76 million. Third-quarter 2007 results benefited from contracts entered into during a contango market as well as the impacts of favorable differentials. The third-quarter 2008 results were negatively affected by increased operating and general and administrative expenses as well as an estimated $7 million to $10 million impact primarily due to lost revenues associated with volume disruptions resulting from Hurricanes Gustav and Ike.

The Partnership’s basic weighted average units outstanding for the third quarter of 2008 totaled 123 million (124 million diluted) as compared to 116 million (117 million diluted) in last year’s third quarter. At September 30, 2008, the Partnership had approximately 123 million units outstanding, long-term debt of approximately $3.2 billion and a long-term debt-to-total capitalization ratio of 47%.

On October 22, 2008, the Partnership declared a quarterly distribution of $0.8925 per unit ($3.57 per unit on an annualized basis) on its outstanding limited partner units. The distribution is payable on November 14, 2008, to holders of record of such units on November 4, 2008. This distribution payment represents increases of approximately 6.3% and 0.6%, respectively, over the quarterly distributions paid in November 2007 and August 2008. This distribution constitutes the 18th consecutive increase in quarterly distributions for the Partnership and the 25th increase in the last thirty-one quarters.

Prior to its conference call on November 6, 2008, the Partnership will furnish a current report on Form 8-K, which will include material in this press release and financial and operational guidance for the fourth quarter of 2008. A copy of the Form 8-K will be available on the Partnership’s website at www.paalp.com.

Non-GAAP Financial Measures

In this release, the Partnership’s EBITDA disclosure is not presented in accordance with generally accepted accounting principles and is not intended to be used in lieu of GAAP

– MORE –

presentations of net income or cash flows from operating activities. EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as 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 present selected items that impact the comparability of our operating results as additional information that may be helpful to your understanding of our financial results. We consider an understanding of these selected items impacting comparability to be material to our evaluation of our operating results and prospects. Although we present selected items that we consider in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions and numerous other factors. These types of variations are not separately identified in this release, but will be discussed, as applicable, in management's discussion and analysis of operating results in our Quarterly Report on Form 10-Q.

A reconciliation of EBITDA to net income and cash flows from operating activities for the periods presented is included in the tables attached to this release. In addition, the Partnership maintains on its website (www.paalp.com) a reconciliation of all non-GAAP financial information, such as EBITDA, to the most comparable GAAP measures. To access the information, investors should click on the "Investor Relations" link on the Partnership's home page and then the "Non-GAAP Reconciliation" link on the Investor Relations page.

Conference Call

The Partnership will host a conference call on Thursday, November 6, 2008 to discuss the following items:

1. The Partnership's third-quarter 2008 performance;

2. The status of major expansion projects;

3. Capitalization and liquidity;

4. Financial and operating guidance for the fourth quarter 2008; and

5. The Partnership's outlook for the future.

The call will begin at 11:00 AM (Eastern). To participate in the call, please dial 877-709-8150, or, for international callers, 201-689-8354, at approximately 10:55 AM (Eastern). No password or reservation number is required.

Webcast Instructions

To access the Internet webcast, please go to the Partnership's website at www.paalp.com, choose "Investor Relations," and then choose "Conference Calls." Following the live webcast, the call will be archived for a period of sixty (60) days on the Partnership's website.

– MORE –

Telephonic Replay Instructions

To listen to a telephonic replay of the conference call, please dial 877-660-6853, or, for international callers, 201-612-7415, and enter account number 232 and replay ID number 298261. The replay will be available beginning Thursday, November 6, 2008, at approximately 1:00 PM (Eastern) and continue until 11:59 PM (Eastern) Saturday, December 6, 2008.

Plains All American Pipeline, L.P. is a publicly traded master limited partnership engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products. Through its 50% ownership in PAA/Vulcan Gas Storage LLC, the partnership is also engaged in the development and operation of natural gas storage facilities. The Partnership is headquartered in Houston, Texas.

Forward Looking Statements

Except for the historical information contained herein, the matters discussed in this news release are forward-looking statements that involve certain risks and uncertainties that could cause actual results to differ materially from results anticipated in the forward-looking statements. These risks and uncertainties include, among other things: failure to implement or capitalize on planned internal growth projects; 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 success of our risk management activities; environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves; abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline system; 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, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves; 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 successful integration and future performance of acquired assets and 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, governmental regulations and interpretations; the effects of competition; 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; risks related to the development and operation of natural gas storage facilities; future developments and circumstances at the time distributions are declared; general economic, market or business conditions; and other factors and uncertainties inherent in the transportation, storage, terminalling, and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products discussed in the Partnership's filings with the Securities and Exchange Commission.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per unit data)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
REVENUES	$ 8,862	$ 5,799	$ 25,118	$ 13,946
COSTS AND EXPENSES				
Purchases and related costs	8,369	5,455	23,929	12,884
Field operating costs	162	134	458	395
General and administrative expenses	39	33	130	128
Depreciation and amortization	49	43	150	135
Total costs and expenses	8,619	5,665	24,667	13,542
OPERATING INCOME	243	134	451	404
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	4	4	11	12
Interest expense	(52)	(39)	(143)	(121)
Interest income and other income (expense), net	14	2	27	8
Income before tax	209	101	346	303
Current income tax expense	(3)	—	(9)	(1)
Deferred income tax benefit (expense)	—	(3)	2	(14)
NET INCOME	$ 206	$ 98	$ 339	$ 288
NET INCOME - LIMITED PARTNERS	$ 173	$ 77	$ 256	$ 231
NET INCOME - GENERAL PARTNER	$ 33	$ 21	$ 83	$ 57
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.15	$ 0.66	$ 2.14	$ 2.06
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.14	$ 0.66	$ 2.12	$ 2.05
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	123	116	120	112
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	124	117	121	113

– MORE –

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

OPERATING DATA [1]	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Transportation activities (Average Daily Volumes, thousands of barrels):				
Tariff activities				
All American	44	46	44	48
Basin	375	397	372	382
Capline	216	230	218	232
Line 63/Line 2000	131	171	151	177
Salt Lake City Area Systems [2]	90	103	94	102
West Texas/New Mexico Area Systems [2]	370	382	367	375

Manito	68	72	70	74
Rainbow	191	—	108	—
Rangeland	54	65	58	64
Refined products	108	110	110	110
Other	1,234	1,129	1,238	1,132
Tariff activities total	2,881	2,705	2,830	2,696
Trucking	101	104	96	107
Transportation activities total	2,982	2,809	2,926	2,803
Facilities activities (Average Monthly Volumes):				
Crude oil, refined products, and LPG storage (average monthly capacity in millions of barrels)	55	47	54	44
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	14	13	13	13
LPG processing (average throughput in thousands of barrels per day)	17	21	16	18
Facilities activities total (average monthly capacity in millions of barrels) [3]	58	50	57	47
Marketing activities (Average Daily Volumes, thousands of barrels):				
Crude oil lease gathering	638	679	663	689
Refined products	27	14	24	10
LPG sales	67	58	85	78
Waterborne foreign crude imported	77	82	84	76
Marketing activities total	809	833	856	853

(1) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.
(2) The aggregate of multiple systems in the respective areas. The volumes for the West Texas/New Mexico Area Systems for the three and nine months ended September 30, 2007 previously included amounts for the Mesa system, which has been reclassified to "Other" for all periods presented.
(3) In order to calculate total facilities activities volume add: (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 period and divided by the number of months in the period.

– MORE –

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(In millions)

	September 30, 2008	December 31, 2007
ASSETS		
Current assets	$ 4,535	$ 3,673
Property and equipment, net	5,061	4,419
Pipeline linefill in owned assets	431	284
Inventory in third-party assets	78	74
Investment in unconsolidated entities	254	215
Goodwill	1,242	1,072
Other long-term assets, net	269	169
Total assets	$ 11,870	$ 9,906
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 4,742	$ 3,729
Long-term debt under credit facilities and other	1	1
Senior notes, net of unamortized discount	3,219	2,623
Other long-term liabilities and deferred credits	257	129
Total liabilities	8,219	6,482
Partners' capital	3,651	3,424
Total liabilities and partners' capital	$ 11,870	$ 9,906

– MORE –

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED EARNINGS PER LIMITED PARTNER UNIT

(In millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 206	$ 98	$ 339	$ 288
Less: General partner's incentive distribution paid	(30)	(20)	(78)	(52)
Subtotal	176	78	261	236
Less: General partner 2% ownership	(3)	(1)	(5)	(5)
Net income available to limited partners	173	77	256	231
Less: Pro forma additional general partner's distribution [1]	(31)	—	—	—
Net income available for limited partners under EITF 03-06	142	77	256	231
Denominator:				
Basic weighted average number of limited partner units outstanding	123	116	120	112
Effect of dilutive securities:				
Weighted average LTIP units	1	1	1	1
Diluted weighted average number of limited partner units outstanding	124	117	121	113
Basic net income per limited partner unit [1]	$ 1.15	$ 0.66	$ 2.14	$ 2.06
Diluted net income per limited partner unit [1]	$ 1.14	$ 0.66	$ 2.12	$ 2.05

[1] Reflects pro forma full distribution of earnings under EITF 03-06. The application of EITF 03-06 negatively impacted basic earnings per limited partner unit and diluted earnings per limited partner unit by $0.26 and $0.25, respectively for the quarter ended September 30, 2008.

– MORE –

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS

(In millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Earnings before interest, taxes, depreciation and amortization ("EBITDA")				
Net income reconciliation				
Net income	$ 206	$ 98	$ 339	$ 288
Add: Interest expense	52	39	143	121
Add: Income tax expense	3	3	7	15
Earnings before interest and taxes ("EBIT")	261	140	489	424
Add: Depreciation and amortization	49	43	150	135
EBITDA	$ 310	$ 183	$ 639	$ 559

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Cash flow from operating activities reconciliation				
EBITDA	$ 310	$ 183	$ 639	$ 559
Current income tax expense	(3)	—	(9)	(1)
Interest expense	(52)	(39)	(143)	(121)
Net change in assets and liabilities, net of acquisitions	(481)	542	(243)	492
Other items to reconcile to cash flows from operating activities:				
Equity earnings in unconsolidated entities, net of distributions	(3)	(3)	(4)	(11)
(Gain) loss on foreign currency revaluation	8	(1)	(2)	(3)

	2008	2007	2008	2007
SFAS 133 mark-to-market adjustment	(163)	13	(72)	15
Inventory valuation adjustment	65	—	65	1
Equity compensation charge	3	1	27	41
Gain on sale of investment assets	(12)	—	(12)	(4)
Other	(1)	—	(7)	1
Net cash provided by operating activities	$ (329)	$ 696	$ 239	$ 969

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Funds flow from operations ("FFO")				
Net income	$ 206	$ 98	$ 339	$ 288
Equity earnings in unconsolidated entities, net of distributions	(3)	(3)	(4)	(11)
Depreciation and amortization	49	43	150	135
Deferred income tax (benefit) expense	—	3	(2)	14
Non-cash amortization of terminated interest rate hedging instruments	—	—	1	—
FFO	252	141	484	426
Maintenance capital	(19)	(10)	(56)	(32)
FFO after maintenance capital	$ 233	$ 131	$ 428	$ 394

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS
(In millions, except per unit data) (continued)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income and earnings per limited partner unit excluding selected items impacting comparability				
Net income	$ 206	$ 98	$ 339	$ 288
Selected items impacting comparability	(87)	13	13	64
Adjusted net income	$ 119	$ 111	$ 352	$ 352
Net income available for limited partners under EITF 03-06	$ 142	$ 77	$ 256	$ 231
Limited partners' 98% of selected items impacting comparability	(85)	13	13	63
Pro forma additional general partner distribution under EITF 03-06	31	—	—	—
Adjusted limited partners' net income	$ 88	$ 90	$ 269	$ 294
Adjusted basic net income per limited partner unit	$ 0.71	$ 0.77	$ 2.24	$ 2.62
Adjusted diluted net income per limited partner unit	$ 0.70	$ 0.77	$ 2.22	$ 2.60
Basic weighted average units outstanding	123	116	120	112
Diluted weighted average units outstanding	124	117	121	113

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
EBITDA excluding selected items impacting comparability				
EBITDA	$ 310	$ 183	$ 639	$ 559
Selected items impacting comparability [(1)]	(87)	13	13	53
Adjusted EBITDA	$ 223	$ 196	$ 652	$ 612

[(1)] The nine-month period ended September 30, 2007 excludes deferred income tax expense as it does not impact EBITDA.

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