PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
November 05, 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) 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 9 Months Ended 09/30/08 | Guidance [(1)] 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 |

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(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.

| | Actual Nine Months Ended September 30 | Calendar 2008 Guidance 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.

| | Actual Nine Months Ended September 30 | Calendar 2008 Guidance 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) |

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(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 II[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 |

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(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 sta 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

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|---|---|---|---|
| Date: November 5, 2008 | By: | /s/ AL SWANSON | |
| | | Name: | Al Swanson |
| | | Title: | *Senior Vice President-Finance* |