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, 2012**

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) Exhibit 99.1 — Press Release dated November 5, 2012

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 2012 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 fourth quarter and full year 2012 detailed guidance for financial performance and we are providing preliminary guidance for calendar year 2013 . In accordance with General Instruction B.2. of Form 8-K, the information presented herein under Item 2.02 and Item 7.01 shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Disclosure of Fourth Quarter 2012 Guidance and Full Year 2013 Preliminary Guidance

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as "non-GAAP financial measures" in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. EBIT and EBITDA (each as defined below in Note 1 to the "Operating and Financial Guidance" table) are non-GAAP financial measures. Net income represents one of the two most directly comparable GAAP measures to EBIT and EBITDA. In Note 10 below, we reconcile net income to EBIT and EBITDA for the 2012 guidance periods presented. Cash flow from operating activities is the other most comparable GAAP measure. We do not, however, reconcile cash flows from operating activities to EBIT and EBITDA, because such reconciliations are impractical for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled "Non-GAAP Reconciliations"), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. In addition, we have highlighted the impact of (i) losses from derivative activities net of inventory valuation adjustments, (ii) asset impairments, (iii) equity compensation expense, (iv) losses on foreign currency revaluation, (v) significant acquisition-related expenses and (vi) other selected items. Due to the nature of the selected items, certain of the selected items impacting comparability may impact certain non-GAAP financial measures but not impact other non-GAAP financial measures.

We based our guidance for the three-month and twelve-month periods ending December 31, 2012 on assumptions and estimates that we believe are reasonable, given our assessment of historical trends (modified for changes in market conditions), business cycles and other reasonably available information. Projections covering multi-quarter periods contemplate inter-period changes in future performance resulting from new expansion projects, seasonal operational changes (such as NGL 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, 2012. We undertake no obligation to publicly update or revise any forward-looking statements.

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

	Actual	Guidance [1]			
	9 Months Ended 9/30/2012	3 Months Ending December 31, 2012		12 Months Ending December 31, 2012	
		Low	High	Low	High
Segment Profit					
Net revenues (including equity earnings from unconsolidated entities)	$ 2,528	$ 870	$ 905	$ 3,398	$ 3,433
Field operating costs	(860)	(307)	(297)	(1,167)	(1,157)
General and administrative expenses	(264)	(80)	(75)	(344)	(339)
	1,404	483	533	1,887	1,937
Depreciation and amortization expense	(356)	(88)	(84)	(444)	(440)
Interest expense, net	(214)	(78)	(74)	(292)	(288)
Income tax benefit (expense)	(43)	(25)	(21)	(68)	(64)
Other income (expense), net	6	1	1	7	7
Net Income	**797**	**293**	**355**	**1,090**	**1,152**
Less: Net income attributable to noncontrolling interests	(23)	(11)	(11)	(34)	(34)
Net Income attributable to Plains	**$ 774**	**$ 282**	**$ 344**	**$ 1,056**	**$ 1,118**
Net Income to Limited Partners [2]	$ 554	$ 200	$ 261	$ 754	$ 815
Basic Net Income Per Limited Partner Unit [2], [3]					
Weighted Average Units Outstanding [3]	322	335	335	325	325
Net Income Per Unit	$ 1.71	$ 0.59	$ 0.77	$ 2.31	$ 2.49
Diluted Net Income Per Limited Partner Unit [2], [3]					
Weighted Average Units Outstanding [3]	325	337	337	328	328
Net Income Per Unit	$ 1.70	$ 0.59	$ 0.77	$ 2.29	$ 2.47
EBIT	**$ 1,054**	**$ 396**	**$ 450**	**$ 1,450**	**$ 1,504**
EBITDA	**$ 1,410**	**$ 484**	**$ 534**	**$ 1,894**	**$ 1,944**
Selected Items Impacting Comparability					
Losses from derivative activities net of inventory valuation adjustments	$ (18)	$ —	$ —	$ (18)	$ (18)
Asset Impairments [4]	(125)	—	—	(125)	(125)
Equity compensation expense	(50)	(11)	(11)	(61)	(61)
Losses on foreign currency revaluation	(6)	—	—	(6)	(6)
Significant acquisition-related expenses	(13)	—	—	(13)	(13)
Other [4]	1	—	—	1	1
Selected Items Impacting Comparability of Net Income attributable to Plains	$ (211)	$ (11)	$ (11)	$ (222)	$ (222)
Excluding Selected Items Impacting Comparability					
Adjusted Segment Profit					
Transportation	$ 543	$ 187	$ 199	$ 730	$ 742
Facilities	362	129	137	491	499
Supply and Logistics	587	178	208	765	795
Other income, net	5	1	1	6	6
Adjusted EBITDA	$ 1,497	$ 495	$ 545	$ 1,992	$ 2,042
Adjusted Net Income attributable to Plains	$ 985	$ 293	$ 355	$ 1,278	$ 1,340
Basic Adjusted Net Income per Limited Partner Unit [2], [3]	$ 2.35	$ 0.63	$ 0.81	$ 2.97	$ 3.15
Diluted Adjusted Net Income per Limited Partner Unit [2], [3]	$ 2.33	$ 0.62	$ 0.80	$ 2.95	$ 3.13

(1) The projected average foreign exchange rate is $1.00 Canadian to $1.00 U.S. for the three-month period ending December 31, 2012. The rate as of

November 2, 2012 was $1.00 Canadian to $1.00 U.S. A $0.05 change in the FX rate will impact annual adjusted EBITDA by approximately $8 million.

(2) We calculate net income available to limited partners based on the distributions pertaining to the current period's net income.

After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

(3) Unit and per-unit amounts are presented as adjusted for the two-for-one unit split effected on October 1, 2012.

(4) Asset impairments and other do not impact adjusted EBITDA. As a component of depreciation and amortization expense, asset impairments are not included in EBITDA and thus do not impact adjusted EBITDA.

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
FASB	Financial Accounting Standards Board
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
NGL	Natural gas liquids. Includes ethane and natural gasoline products as well as propane and butane, which are often referred to as liquefied petroleum gas (LPG). When used in this document NGL refers to all NGL products including LPG.
FX	Foreign currency exchange
General partner (GP)	As the context requires, "general partner" refers to any or all of (i) PAA GP LLC, the owner of our 2% general partner interest, (ii) Plains AAP, L.P., the sole member of PAA GP LLC and owner of our incentive distribution rights and (iii) Plains All American GP LLC, the general partner of Plains AAP, L.P.

2. *Operating Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. The following is a brief explanation of the operating activities for each segment as well as key metrics.

   a. *Transportation.* Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil, NGL and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in the Butte, Frontier and White Cliffs pipeline systems and Settoon Towing, in which we own non-controlling interests.

   Pipeline volume estimates are based on historical trends, anticipated future operating performance and assumed completion of internal growth projects. Actual volumes will be influenced by maintenance schedules at refineries, production trends, weather and other natural occurrences including hurricanes, changes in the quantity of inventory held in tanks, and other external factors beyond our control. We forecast adjusted segment profit using the volume assumptions in the table below, priced at forecasted tariff rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation. Actual segment profit could vary materially depending on the level and mix of volumes transported or expenses incurred during the period.

   The following table summarizes our total transportation volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

	Actual	Guidance	
	Nine Months Ended Sep 30, 2012	Three Months Ending Dec 31, 2012	Twelve Months Ending Dec 31, 2012
Average Daily Volumes (MBbls/d)			
Crude Oil Pipelines			
All American	31	35	32
Basin	495	510	499
Capline	144	160	148
Line 63 / 2000	126	125	126
Salt Lake City Area Systems (1)	141	140	141
Permian Basin Area Systems (1)	450	470	455
Mid-Continent Area Systems (1)	247	265	252
Manito	59	50	57
Rainbow	147	145	146
Rangeland	60	55	59
Other	1,140	1,255	1,169
NGL Pipelines	163	205	174
Refined Products Pipelines	114	95	109
	3,317	3,510	3,367
Trucking	103	105	104

	3,420	3,615	3,471
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.58	$ 0.58(2)	$ 0.58(2)

(1) The aggregate of multiple systems in their 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, NGL and natural gas, as well as NGL fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

Adjusted segment profit is forecasted 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	Guidance	
	Nine Months Ended Sep 30, 2012	Three Months Ending Dec 31, 2012	Twelve Months Ending Dec 31, 2012
Operating Data			
Crude oil, refined products and NGL storage (MMBbls/Mo.)	88	94	90
Natural Gas Storage (Bcf/Mo.)	82	93	84
NGL Fractionation (MBbls/d)	73	105	81
Facilities Activities Total			
Avg. Capacity (MMBbls/Mo.) (1)	104	113	106
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.39	$ 0.39(2)	$ 0.39(2)

(1) Calculated as the sum of: (i) crude oil, refined products and NGL storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes (based on estimated utilized capacity), multiplied by the number of days in the period and divided by the number of months in the period.
(2) Mid-point of guidance.

c. *Supply and Logistics*. Our supply and logistics segment operations generally consist of the following activities:

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

We characterize a substantial portion of the profit generated by our supply and logistics segment as fee equivalent. This portion of the segment profit is generated by the purchase and resale of crude oil on an index-related basis, which results in us generating a gross margin for such activities. This gross margin is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil to market as well as any operating and general and administrative expenses. The level of profit associated with a portion of the other activities we conduct in the supply and logistics segment is influenced by overall market structure and the degree of volatility in the crude oil market, as well as variable operating expenses. Forecasted operating results for the three-month period ending December 31, 2012 reflect the current market structure and seasonal, weather-related variations in NGL sales. Variations in weather, market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast adjusted segment profit using the volume assumptions stated below, as well as estimates of unit margins, field operating costs, G&A expenses and carrying costs for contango inventory, based on current and anticipated market conditions. Actual volumes are influenced by temporary market-driven storage and withdrawal of oil, maintenance schedules at refineries, actual production levels, weather, and other external factors beyond our control. Field operating costs do not include depreciation. Realized unit margins for any given lease-gathered barrel could vary significantly based on a variety of factors including location, quality, and contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Actual	Guidance	
	Nine Months Ended Sep 30, 2012	Three Months Ending Dec 31, 2012	Twelve Months Ending Dec 31, 2012
Average Daily Volumes (MBbl/d)			
Crude Oil Lease Gathering Purchases	808	835	815
NGL Sales	155	260	181

Waterborne cargos	3	—	2
	966	1,095	998
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 2.22	$ 1.92[1]	$ 2.14[1]

(1) Mid-point of guidance.

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

4. *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 we may commit to after the date hereof. We forecast capital expenditures during calendar 2012 to be approximately $1.15 billion for expansion projects with an additional $160 to $170 million for maintenance capital projects. During the first nine months of 2012, we invested $831 million and $123 million for expansion and maintenance projects, respectively. The following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2012:

	Calendar 2012 (in millions)
Expansion Capital	
· Eagle Ford Project	$125
· Spraberry Area Pipeline Projects	90
· Gardendale Gathering System [1]	85
· Rainbow II Pipeline	75
· PAA Natural Gas Storage (multiple projects)	61
· Bakken North	50
· Rail Projects [2]	50
· Mississippian Lime Project	45
· St. James Terminal Expansion [3]	45
· Yorktown Terminal Project	35
· Cushing Terminal Expansion [3]	30
· BP NGL Acquisition Related Projects	25
· Patoka Terminal Expansion [3]	25
· Shafter Expansion	18
· Other Projects [4]	391
	$1,150
Potential Adjustments for Timing / Scope Refinement [5]	- $50 + $100
Total Projected Expansion Capital Expenditures	$1,100 - $1,250
Maintenance Capital Expenditures	$160 - $170

(1) Includes pipeline, tankage and condensate stabilization.
(2) Excludes rail project associated with the Yorktown terminal project.
(3) Includes carryover capital from 2011 expansions as well as new expansions.
(4) Primarily multiple, smaller projects comprised of pipeline connections, upgrades and truck stations, new tank construction and refurbishing, pipeline linefill purchases and carry-over of projects from prior years.
(5) Potential variation to current capital costs estimates may result from changes to project design, final cost of materials and labor and timing of incurrence of costs due to uncontrollable factors such as permits, regulatory approvals and weather.

5. *Capital Structure.* This guidance is based on our capital structure as of September 30, 2012 and adjusted for estimated equity issuances under our continuous offering program.

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

   Included in interest expense are commitment fees, amortization of long-term debt discounts or premiums, deferred amounts associated with terminated interest-rate hedges and interest on short-term debt for non-contango inventory (primarily hedged NGL inventory and New York Mercantile Exchange and Intercontinental Exchange 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 hedged inventory borrowings as carrying costs of crude oil and NGL and include it in purchases and related costs.

7. *Income Taxes*. We expect Canadian income tax expense/(benefit) to be approximately $23 million and $66 million for the three-month and twelve-month periods ending December 31, 2012, respectively, of which approximately $22 million and $54 million, respectively, is classified as current. For the twelve-month period ending December 31, 2012 we expect to have a deferred tax expense of $12 million. All or part of the income tax expense of $66 million may result in a tax credit to our equity holders.

8. *Reconciliation of Adjusted EBITDA to Implied DCF.* The following table reconciles the mid-point of adjusted EBITDA to implied distributable cash flow for the three-month and twelve-month periods ending December 31, 2012.

	Mid-Point Guidance	
	Three Months Ending December 31, 2012	Twelve Months Ending December 31, 2012
	(in millions)	
Adjusted EBITDA	$ 520	$ 2,017
Interest expense, net	(76)	(290)
Current income tax benefit (expense)	(22)	(54)
Distributions to noncontrolling interests	(12)	(48)
Maintenance capital expenditures	(42)	(165)
Other, net	1	3
Implied DCF	$ 369	$ 1,463

9. *Equity Compensation Plans.* The majority of grants outstanding under our various equity compensation plans contain vesting criteria that are based on a combination of performance benchmarks and service periods. The grants will vest in various percentages, typically on the later to occur of specified vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of November 5, 2012, estimated vesting dates range from November 2012 to May 2019 and annualized distribution levels range from $1.925 to $2.40. For some awards, a percentage of any units remaining unvested as of a certain date will vest on such date and all others will be forfeited.

   On October 4, 2012, we declared an annualized distribution of $2.17 payable on November 14, 2012 to our unitholders of record as of November 2, 2012. For the purposes of guidance, we have made the assessment that a $2.35 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of $46.00 per unit as well as an accrual associated with awards that will vest on a certain date. The actual amount of equity compensation expense 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 vesting date, (iii) the probability assessment regarding distributions, and (iv) new equity compensation award grants. For example, a $2.00 change in the unit price during the fourth-quarter would change the fourth-quarter equity compensation expense by approximately $4 million. Therefore, actual net income could differ from our projections.

10. *Reconciliation of Net Income to EBIT and EBITDA.* The following table reconciles net income to EBIT and EBITDA for the nine-month period ending September 30, 2012 and three-month and twelve-month periods ending December 31, 2012.

	Actual	Guidance			
	9 Months Ended Sep 30, 2012	3 Months Ending Dec 31, 2012		12 Months Ending Dec 31, 2012	
		Low	High	Low	High
			(in millions)		
Reconciliation to EBITDA					
Net Income	$ 797	$ 293	$ 355	$ 1,090	$ 1,152
Interest expense, net	214	78	74	292	288
Income tax expense (benefit)	43	25	21	68	64
EBIT	1,054	396	450	1,450	1,504
Depreciation and amortization	356	88	84	444	440
EBITDA	$ 1,410	$ 484	$ 534	$ 1,894	$ 1,944

Preliminary 2013 Guidance

Our preliminary adjusted EBITDA guidance for 2013 is based on (i) operating and financial performance of our existing assets that is assumed to be generally in line with recent performance trends, appropriately adjusted for known and expected developments as well as estimated market conditions, (ii) achievement of targeted performance levels for recent acquisitions and (iii) contributions from expansion capital projects in line with our expectations. In addition, our preliminary 2013 guidance does not include any forecast for acquisitions that we may commit to after the date hereof. The following table summarizes the range of selected key financial data of our preliminary guidance for calendar year 2013.

Preliminary Calendar 2013 Guidance (in millions)

	Low	High
Adjusted EBITDA	$ 1,875	$ 1,975
Interest expense, net	(320)	(310)
Current income tax benefit (expense)	(45)	(35)
Distributions to noncontrolling interests	(50)	(46)
Maintenance capital expenditures	(180)	(160)
Other, net	—	—
Implied DCF	1,280	1,424
Expansion Capital	$ 900	$ 1,100

Our preliminary guidance for interest expense is based on our capital structure as of September 30, 2012 and adjusted for estimated equity issuances under our continuous equity offering program, approved capital projects for 2012, and the assumption that 2013 capital projects will range between $900 million and $1.1 billion. Our preliminary guidance for maintenance capital expenditures is based on our estimated average level of recurring expenditures of approximately $170 million. Our preliminary guidance for adjusted net income and adjusted EBITDA does not include a forecast of selected items impacting comparability, such as equity compensation expense, as it is impractical to forecast such items.

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 incorporating the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast," as well as similar expressions and statements regarding our business strategy, plans and objectives 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 to be reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- failure to implement or capitalize, or delays in implementing or capitalizing, on planned internal growth projects;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- 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 effectiveness 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 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 impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;
- the effects of competition;
- interruptions in service 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;
- factors affecting demand for natural gas and natural gas storage services and rates;
- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

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, 2012

By: /s/ Charles Kingswell-Smith

Name: Charles Kingswell-Smith

Title: *Vice President and Treasurer*

PLAINS ALL AMERICAN PIPELINE, L.P.

News Release

FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P. Reports
Third-Quarter 2012 Results

(Houston — November 5, 2012) Plains All American Pipeline, L.P. (NYSE: PAA) today reported net income attributable to Plains for the third quarter of 2012 of $165 million, or $0.27 per diluted limited partner unit. These results include the impact of non-cash asset impairment charges totaling $125 million, primarily related to the Partnership's determination not to proceed with the development of the Pier 400 terminal project in California. Such results compare to net income attributable to Plains of $281 million, or $0.74 per diluted limited partner unit for the third quarter of 2011. The Partnership reported earnings before interest, taxes, depreciation and amortization ("EBITDA") of $470 million for the third quarter of 2012, compared to reported EBITDA of $421 million for the third quarter of 2011.

The Partnership's reported results include the impact of items that affect comparability between reporting periods. The impact of items impacting comparability are excluded from adjusted results, as detailed in the table below. Accordingly, the Partnership's third-quarter 2012 adjusted net income attributable to Plains, adjusted net income per diluted limited partner unit and adjusted EBITDA were $322 million, $0.73 and $502 million, respectively. The comparable amounts for the third quarter of 2011 were $274 million, $0.71 and $414 million. (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 their reconciliation to the most directly comparable GAAP measures.)

"Continuing a multi-quarter trend, PAA delivered strong adjusted results for the third quarter of 2012," said Greg L. Armstrong, Chairman and CEO of Plains All American. "The environment for crude oil production growth in North America remains very favorable and we continue to experience strong demand for our assets and services. As a result, we have increased our midpoint guidance for adjusted EBITDA to slightly over $2 billion for the full year of 2012, representing a 7% increase over our previous guidance midpoint for 2012.

"We are also expanding our asset base to meet the growing needs of our customers. Thus far in 2012, we have invested approximately $2.5 billion in organic growth projects and acquisitions and expect to incrementally invest over $1 billion in organic growth projects through the end of 2013. These investments provide meaningful visibility for increased baseline cash flow and distributions to unitholders."

Armstrong added, "In addition to delivering solid operating and financial results, we ended the quarter with a strong balance sheet, credit metrics favorable to our targets and approximately $2.4 billion of committed liquidity. As a result, we are well positioned to finance our growth while maintaining a solid financial position."

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The following table summarizes selected items that the Partnership believes impact comparability of financial results between reporting periods (amounts in millions, except per unit amounts):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Selected Items Impacting Comparability - Income / (Loss) [(1)] [(2)]**:**				
Gains/(losses) from derivative activities net of inventory valuation adjustments [(3)]	$ (31)	$ 30	$ (18)	$ 71
Asset impairments [(4)]	(125)	—	(125)	—
Equity compensation expense [(5)]	(12)	(6)	(50)	(40)
Net loss on early repayment of senior notes	—	—	—	(23)
Net gain/(loss) on foreign currency revaluation	11	(17)	(6)	(17)
Significant acquisition-related expenses	—	—	(13)	(4)
Other [(6)]	—	—	1	2
Selected items impacting comparability of net income attributable to Plains	$ (157)	$ 7	$ (211)	$ (11)
Impact to basic net income per limited partner unit	$ (0.46)	$ 0.02	$ (0.64)	$ (0.03)
Impact to diluted net income per limited partner unit	$ (0.46)	$ 0.03	$ (0.63)	$ (0.03)

(1) Per-unit amounts are presented as adjusted for the two-for-one unit split effected on October 1, 2012.
(2) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
(3) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period net of inventory valuation adjustments.
(4) Asset impairments are reflected in "Depreciation and amortization" on our Consolidated Statements of Operations and do not impact the comparability of EBITDA.

(5) Equity compensation expense for the three and nine months ended September 30, 2012 and 2011 excludes the portion of equity compensation expense represented by grants under our Long-term Incentive Plans ("LTIPs") that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units.

(6) Includes other immaterial selected items impacting comparability, as well as the noncontrolling interests' portion of selected items.

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

	Three Months Ended September 30, 2012			Three Months Ended September 30, 2011		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues (1)	$ 364	$ 262	$ 9,049	$ 300	$ 191	$ 8,545
Purchases and related costs (1)	(36)	(29)	(8,776)	(34)	(45)	(8,259)
Field operating costs (excluding equity compensation expense) (1)	(119)	(72)	(101)	(97)	(38)	(84)
Equity compensation expense - operations	(3)	—	(1)	(1)	—	—
Segment G&A expenses (excluding equity compensation expense) (2)	(23)	(16)	(24)	(16)	(11)	(20)
Equity compensation expense - general and administrative	(8)	(5)	(5)	(4)	(2)	(3)
Equity earnings in unconsolidated entities	9	—	—	4	—	—
Reported segment profit	$ 184	$ 140	$ 142	$ 152	$ 95	$ 179
Selected items impacting comparability of segment profit (3)	6	2	27	3	1	(18)
Segment profit excluding selected items impacting comparability	$ 190	$ 142	$ 169	$ 155	$ 96	$ 161
Maintenance capital	$ 26	$ 17	$ 4	$ 17	$ 6	$ 2

	Nine Months Ended September 30, 2012			Nine Months Ended September 30, 2011		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues (1)	$ 1,043	$ 785	$ 27,368	$ 864	$ 516	$ 24,567
Purchases and related costs (1)	(100)	(168)	(26,414)	(88)	(88)	(23,794)
Field operating costs (excluding equity compensation expense) (1)	(343)	(204)	(308)	(293)	(122)	(225)
Equity compensation expense - operations	(12)	(2)	(2)	(6)	(1)	(1)
Segment G&A expenses (excluding equity compensation expense) (2)	(73)	(48)	(77)	(49)	(35)	(67)
Equity compensation expense - general and administrative	(24)	(19)	(23)	(21)	(11)	(16)
Equity earnings in unconsolidated entities	25	—	—	9	—	—
Reported segment profit	$ 516	$ 344	$ 544	$ 416	$ 259	$ 464
Selected items impacting comparability of segment profit (3)	27	18	43	18	14	(50)
Segment profit excluding selected items impacting comparability	$ 543	$ 362	$ 587	$ 434	$ 273	$ 414
Maintenance capital	$ 78	$ 34	$ 11	$ 52	$ 16	$ 9

(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. Includes acquisition-related expenses for both the 2012 and 2011 periods.

(3) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

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Adjusted Transportation segment profit in the third quarter of 2012 increased by 23% over comparable 2011 results. This increase was primarily driven by higher revenues from acquisitions completed late in 2011 and early in 2012, organic growth capacity expansions, increased pipeline volumes and higher average pipeline tariffs. These increases in revenue were partially offset by higher operating and general and administrative expenses, commensurate with the growth of the business.

Adjusted Facilities segment profit in the third quarter of 2012 increased 48% over comparable 2011 results. This increased profitability is primarily related to capacity additions from the BP NGL acquisition and recently completed organic growth projects.

Adjusted Supply and Logistics segment profit in the third quarter of 2012 increased 5% over comparable 2011 results. This increase was primarily due to favorable crude oil market conditions and increased crude oil lease gathering and NGL sales volumes.

The Partnership's basic weighted average units outstanding for the third quarter of 2012 was 329 million units (331 million diluted) as compared to 299 million units (300 million diluted) in last year's third quarter. At the end of the third quarter, the Partnership had approximately 331.6 million units outstanding. These amounts have been adjusted for the two-for-one unit split effected on October 1, 2012. The Partnership had long-term debt of approximately $5.8 billion and a long-term debt-to-total capitalization ratio of 46% at the end of the third quarter.

The Partnership has declared a quarterly distribution of $0.5425 per unit ($2.17 per unit on an annualized basis) payable November 14, 2012, on its outstanding limited partner units. This distribution represents an increase of approximately 9.0% over the quarterly distribution paid in November 2011 and an increase of approximately 1.9% over the quarterly distribution paid in August 2012.

The Partnership will hold a conference call at 9:00 AM (Central) on November 6, 2012 (see details below). Prior to this conference call, 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 and full-year 2012 as well as preliminary financial guidance for 2013. A copy of the Form 8-K will be available on the Partnership's website at www.paalp.com.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as "non-GAAP financial measures" in its evaluation of past performance and prospects for the future. These measures include adjusted EBITDA and implied distributable cash flow ("DCF"). Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), (iii) items that are not indicative of our core operating results and business outlook and/or (iv) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items as "Selected Items Impacting Comparability." These additional financial measures are reconciled from the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

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. A full analysis of 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.

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Conference Call

The Partnership will host a conference call at 9:00 AM (Central) on Tuesday, November 6, 2012 to discuss the following items:

1. The Partnership's third-quarter 2012 performance;
2. The status of major expansion projects;
3. Capitalization and liquidity;
4. Financial and operating guidance for the fourth-quarter and full-year 2012;
5. Preliminary 2013 adjusted EBITDA guidance and growth capital investments; and
6. The Partnership's outlook for the future.

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.

Alternatively, you may access the live conference call by dialing toll free (800) 230-1085. International callers should dial (612) 332-0226. No password is required. You may access the slide presentation accompanying the conference call a few minutes prior to the call under the Conference Call Summaries portion of the Conference Calls tab of the Investor Relations section of PAA's website at www.paalp.com.

Telephonic Replay Instructions

To listen to a telephonic replay of the conference call, please dial (800) 475-6701, or, for international callers, (320) 365-3844, and replay access code 260375. The replay will be available beginning Tuesday, November 6, 2012, at approximately 11:00 AM (Central) and continue until 11:59 PM (Central) Thursday, December 6, 2012.

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Forward Looking Statements

Except for the historical information contained herein, the matters discussed in this 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, the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations; failure to implement or capitalize, or delays in implementing or capitalizing, on planned internal growth projects; unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof); 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 effectiveness 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 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 impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations; the effects of competition; interruptions in service 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; factors affecting demand for natural gas and natural gas storage services and rates; general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids discussed in the Partnership's filings with the Securities and Exchange Commission.

Plains All American Pipeline, L.P. is a publicly traded master limited partnership engaged in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the processing, transportation, fractionation, storage and marketing of natural gas liquids. Through its general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), PAA owns and operates natural gas storage facilities. PAA is headquartered in Houston, Texas.

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

CONSOLIDATED STATEMENTS OF OPERATIONS [1]
(in millions, except per unit data)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
REVENUES	$ 9,354	$ 8,837	$ 28,358	$ 25,390
COSTS AND EXPENSES				
Purchases and related costs	8,524	8,142	25,855	23,423
Field operating costs	292	217	860	638
General and administrative expenses	81	56	264	199
Depreciation and amortization [2]	210	65	356	191

Total costs and expenses	9,107	8,480	27,335	24,451
OPERATING INCOME	247	357	1,023	939
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	9	4	25	9
Interest expense	(74)	(62)	(214)	(190)
Other income/(expense), net	4	(5)	6	(24)
INCOME BEFORE TAX	186	294	840	734
Current income tax expense	(10)	(7)	(32)	(25)
Deferred income tax (expense)/benefit	(3)	1	(11)	(3)
NET INCOME	173	288	797	706
Less: Net income attributable to noncontrolling interests	(8)	(7)	(23)	(18)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 165	$ 281	$ 774	$ 688
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 89	$ 221	$ 554	$ 520
GENERAL PARTNER	$ 76	$ 60	$ 220	$ 168
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.27	$ 0.74	$ 1.71	$ 1.77
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.27	$ 0.74	$ 1.70	$ 1.76
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	329	299	322	294
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	331	300	325	296

(1) Unit and per-unit amounts are presented as adjusted for the two-for-one unit split effected on October 1, 2012.

(2) For both the three and nine months ended September 30, 2012, includes impairment losses of approximately $125 million, primarily related to the Pier 400 terminal project.

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

OPERATING DATA (1)	**Three Months Ended September 30, 2012**	**2011**	**Nine Months Ended September 30, 2012**	**2011**
Transportation activities (average daily volumes in thousands of barrels):				
Crude Oil Pipelines				
All American	38	38	31	36
Basin	474	443	495	432
Capline	159	121	144	165
Line 63/Line 2000	131	126	126	114
Salt Lake City Area Systems (2)	146	142	141	139
Permian Basin Area Systems (2)	451	408	450	402
Mid-Continent Area Systems (2)	257	217	247	217
Manito	51	65	59	66
Rainbow	142	96	147	132
Rangeland	57	60	60	57
Other	1,141	1,096	1,140	1,063
NGL Pipelines	264	—	163	—
Refined Products Pipelines	112	104	114	99
Tariff activities total	3,423	2,916	3,317	2,922
Trucking	107	109	103	104
Transportation activities total	3,530	3,025	3,420	3,026
Facilities activities (average monthly volumes):				
Crude oil, refined products and NGL storage (average monthly capacity in millions of barrels)	94	71	88	69
Natural gas storage (average monthly capacity in billions of cubic feet)	89	75	82	69
NGL fractionation (average throughput in thousands of barrels per day)	100	16	73	14

Facilities activities total (average monthly capacity in millions of barrels) (3)	111	84	104	81
Supply and Logistics activities (average daily volumes in thousands of barrels):				
Crude oil lease gathering purchases	811	748	808	731
NGL sales	179	77	155	97
Waterborne cargos	5	27	3	28
Supply and Logistics activities total	995	852	966	856

(1) Volumes associated with acquisitions represent total volumes for the number of days or months we actually owned the assets divided by the number of days or months in the period.

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

(3) Facilities total is calculated as the sum of: (i) crude oil, refined products and NGL storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

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

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(in millions)

	September 30, 2012	December 31, 2011
ASSETS		
Current assets	$ 4,813	$ 4,351
Property and equipment, net	9,348	7,740
Goodwill	2,119	1,854
Linefill and base gas	714	564
Long-term inventory	287	135
Investments in unconsolidated entities	289	191
Other, net	617	546
Total assets	$ 18,187	$ 15,381
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 4,886	$ 4,511
Senior notes, net of unamortized discount	5,511	4,262
Long-term debt under credit facilities and other	300	258
Other long-term liabilities and deferred credits	565	376
Total liabilities	11,262	9,407
Partners' capital excluding noncontrolling interests	6,420	5,450
Noncontrolling interests	505	524
Total partners' capital	6,925	5,974
Total liabilities and partners' capital	$ 18,187	$ 15,381

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

CREDIT RATIOS
(in millions)

	September 30, 2012	December 31, 2011
Short-term debt	$ 834	$ 679
Long-term debt	5,811	4,520

Total debt	$	6,645	$	5,199
Long-term debt		5,811		4,520
Partners' capital		6,925		5,974
Total book capitalization	$	12,736	$	10,494
Total book capitalization, including short-term debt	$	13,570	$	11,173
Long-term debt-to-total book capitalization		46%		43%
Total debt-to-total book capitalization, including short-term debt		49%		47%

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

COMPUTATION OF BASIC AND DILUTED EARNINGS PER LIMITED PARTNER UNIT [(1)]
(in millions, except per unit data)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Numerator for Basic and Diluted Net Income per Limited Partner Unit:				
Net income attributable to Plains	$ 165	$ 281	$ 774	$ 688
Less: General partner's incentive distribution [(2)]	(74)	(55)	(208)	(158)
Less: General partner 2% ownership [(2)]	(2)	(5)	(12)	(10)
Net income available to limited partners	89	221	554	520
Less: Undistributed earnings allocated and distributions to participating securities [(2)]	(1)	—	(3)	—
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 88	$ 221	$ 551	$ 520
Denominator for Basic and Diluted Net Income per Limited Partner Unit:				
Basic weighted average number of limited partner units outstanding	329	299	322	294
Effect of dilutive securities: Weighted average LTIP units [(3)]	2	1	3	2
Diluted weighted average number of limited partner units outstanding	331	300	325	296
Basic net income per limited partner unit	$ 0.27	$ 0.74	$ 1.71	$ 1.77
Diluted net income per limited partner unit	$ 0.27	$ 0.74	$ 1.70	$ 1.76

(1) Unit and per-unit amounts are presented as adjusted for the two-for-one unit split effected on October 1, 2012.
(2) We calculate net income available to limited partners based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.
(3) Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

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

FINANCIAL DATA RECONCILIATIONS
(in millions)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net income to earnings before interest, taxes, depreciation and amortization				

	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
("EBITDA") and excluding selected items impacting comparability ("Adjusted EBITDA") reconciliations				
Net Income	$ 173	$ 288	$ 797	$ 706
Add: Interest expense	74	62	214	190
Add: Income tax expense	13	6	43	28
Add: Depreciation and amortization	210	65	356	191
EBITDA	$ 470	$ 421	$ 1,410	$ 1,115
Selected items impacting comparability of EBITDA [1]	32	(7)	87	13
Adjusted EBITDA	$ 502	$ 414	$ 1,497	$ 1,128

(1) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Adjusted EBITDA to Implied Distributable Cash Flow ("DCF")				
Adjusted EBITDA	$ 502	$ 414	$ 1,497	$ 1,128
Interest expense	(74)	(62)	(214)	(190)
Maintenance capital	(47)	(25)	(123)	(77)
Current income tax expense	(10)	(7)	(32)	(25)
Equity earnings in unconsolidated entities, net of distributions	1	2	2	7
Distributions to noncontrolling interests [1]	(12)	(12)	(36)	(35)
Other	—	—	—	(1)
Implied DCF	$ 360	$ 310	$ 1,094	$ 807

(1) Includes distributions that pertain to the current quarter's net income and are to be paid in the subsequent quarter.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Cash flow from operating activities reconciliation				
EBITDA	$ 470	$ 421	$ 1,410	$ 1,115
Current income tax expense	(10)	(7)	(32)	(25)
Interest expense	(74)	(62)	(214)	(190)
Net change in assets and liabilities, net of acquisitions	125	418	(366)	796
Other items to reconcile to cash flows from operating activities:				
Equity compensation expense	22	10	82	56
Net cash provided by operating activities	$ 533	$ 780	$ 880	$ 1,752

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

FINANCIAL DATA RECONCILIATIONS [1]
(in millions, except per unit data) (continued)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Basic Adjusted Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 165	$ 281	$ 774	$ 688
Selected items impacting comparability of net income attributable to Plains	157	(7)	211	11
Adjusted net income attributable to Plains	322	274	985	699
Less: General partner's incentive distribution [2]	(74)	(55)	(208)	(158)
Less: General partner 2% ownership [2]	(5)	(5)	(16)	(10)
Adjusted net income available to limited partners	243	214	761	531
Less: Undistributed earnings allocated and distributions to participating securities [2]	(2)	—	(5)	—
Adjusted limited partners' net income	$ 241	$ 214	$ 756	$ 531
Basic weighted average number of limited partner units outstanding	329	299	322	294
Basic adjusted net income per limited partner unit	$ 0.73	$ 0.72	$ 2.35	$ 1.80
Diluted Adjusted Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 165	$ 281	$ 774	$ 688
Selected items impacting comparability of net income attributable to Plains	157	(7)	211	11

Adjusted net income attributable to Plains		322		274		985		699
Less: General partner's incentive distribution [2]		(74)		(55)		(208)		(158)
Less: General partner 2% ownership [2]		(5)		(5)		(16)		(10)
Adjusted net income available to limited partners		243		214		761		531
Less: Undistributed earnings allocated and distributions to participating securities [2]		(1)		—		(3)		—
Adjusted limited partners' net income	$	242	$	214	$	758	$	531
Diluted weighted average number of limited partner units outstanding		331		300		325		296
Diluted adjusted net income per limited partner unit	$	0.73	$	0.71	$	2.33	$	1.79

(1) Unit and per-unit amounts are presented as adjusted for the two-for-one unit split effected on October 1, 2012.

(2) We calculate adjusted net income available to limited partners based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

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