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) — **August 6, 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 August 6, 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 second-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 detailed guidance for financial performance for the third and fourth quarters of calendar 2012. 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 Third and Fourth Quarter 2012 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) inventory valuation adjustments net of gains from related derivative activities, (ii) gains from other derivative activities, (iii) equity compensation expense, (iv) losses on foreign currency revaluation,

(v) 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 period ending September 30, 2012, and 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 August 5, 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)					
	6 Months Ended 6/30/2012	3 Months Ending September 30, 2012		3 Months Ending December 31, 2012		12 Months Ending December 31, 2012	
		Low	High	Low	High	Low	High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 1,688	$ 776	$ 804	$ 824	$ 852	$ 3,288	$ 3,344
Field operating costs	(568)	(318)	(310)	(303)	(295)	(1,189)	(1,173)
General and administrative expenses	(182)	(80)	(76)	(76)	(72)	(338)	(330)
	938	378	418	445	485	1,761	1,841
Depreciation and amortization expense	(146)	(87)	(84)	(87)	(84)	(320)	(314)
Interest expense, net	(140)	(79)	(76)	(79)	(76)	(298)	(292)
Income tax benefit (expense)	(30)	(2)	2	(17)	(14)	(49)	(42)
Other income (expense), net	2	1	1	1	1	4	4
Net Income	**624**	**211**	**261**	**263**	**312**	**1,098**	**1,197**
Less: Net income attributable to noncontrolling interests	(15)	(7)	(7)	(11)	(11)	(33)	(33)
Net Income attributable to Plains	**$ 609**	**$ 204**	**$ 254**	**$ 252**	**$ 301**	**$ 1,065**	**$ 1,164**
Net Income to Limited Partners (2)	$ 465	$ 129	$ 178	$ 172	$ 220	$ 770	$ 867
Basic Net Income Per Limited Partner Unit (2)							
Weighted Average Units Outstanding	159	164	164	165	165	162	162
Net Income Per Unit	$ 2.90	$ 0.78	$ 1.08	$ 1.04	$ 1.33	$ 4.71	$ 5.30
Diluted Net Income Per Limited Partner Unit (2)							
Weighted Average Units Outstanding	161	165	165	166	166	163	163
Net Income Per Unit	$ 2.88	$ 0.77	$ 1.07	$ 1.03	$ 1.32	$ 4.67	$ 5.27
EBIT	**$ 794**	**$ 292**	**$ 335**	**$ 359**	**$ 402**	**$ 1,445**	**$ 1,531**
EBITDA	**$ 940**	**$ 379**	**$ 419**	**$ 446**	**$ 486**	**$ 1,765**	**$ 1,845**
Selected Items Impacting Comparability							
Inventory valuation adjustments net of gains from related derivative activities	$ (5)	$ —	$ —	$ —	$ —	$ (5)	$ (5)
Gains from other derivative activities	18	—	—	—	—	18	18
Equity compensation expense	(38)	(11)	(11)	(9)	(9)	(58)	(58)
Losses on foreign currency revaluation	(16)	—	—	—	—	(16)	(16)
Acquisition related expenses	(13)	—	—	—	—	(13)	(13)
Selected Items Impacting Comparability of Net Income attributable to Plains	$ (54)	$ (11)	$ (11)	$ (9)	$ (9)	$ (74)	$ (74)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 353	$ 183	$ 193	$ 205	$ 215	$ 741	$ 761
Facilities	219	112	118	132	138	463	475
Supply and Logistics	419	94	118	117	141	630	678
Other income, net	4	1	1	1	1	6	6
Adjusted EBITDA	$ 995	$ 390	$ 430	$ 455	$ 495	$ 1,840	$ 1,920
Adjusted Net Income attributable to Plains	$ 663	$ 215	$ 265	$ 261	$ 310	$ 1,139	$ 1,238
Basic Adjusted Net Income per Limited Partner Unit	$ 3.23	$ 0.84	$ 1.14	$ 1.09	$ 1.38	$ 5.15	$ 5.75
Diluted Adjusted Net Income per Limited Partner Unit	$ 3.21	$ 0.84	$ 1.13	$ 1.09	$ 1.38	$ 5.12	$ 5.71

(1) The projected average foreign exchange rate is $1.00 Canadian to $1.00 U.S. for the three-month periods ending September 30, 2012 and December 31, 2012. The rate as of August 3, 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 $10 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.

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
LPG	Liquefied petroleum gas and other natural gas-related products
NGL	Natural gas liquids. Includes ethane and natural gasoline products as well as propane and butane, which are often referred to as 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 noncontrolling 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		
	Six Months Ended Jun 30, 2012	**Three Months Ending Sep 30, 2012**	**Three Months Ending Dec 31, 2012**	**Twelve Months Ending Dec 31, 2012**
Average Daily Volumes (000 Bbls/d)				
All American	28	35	35	32
Basin	505	500	500	502
Capline	136	145	145	141
Line 63 / 2000	124	125	125	125
Salt Lake City Area Systems [1]	138	140	140	139
Permian Basin Area Systems [1]	450	460	490	463
Mid-Continent Area Systems [1]	236	245	250	242
Manito	62	60	60	61
Rainbow	149	155	150	151
Rangeland	62	50	60	58
NGL	111	220	220	166
Refined Products	115	105	100	109
Other	1,147	1,220	1,230	1,186
	3,263	3,460	3,505	3,375
Trucking	102	125	125	114
	3,365	3,585	3,630	3,489
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.58	$ 0.57[2]	$ 0.63[2]	$ 0.59[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		
	Six Months Ended Jun 30, 2012	**Three Months Ending 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.)	85	95	95	90
Natural Gas Storage (Bcf/Mo.)	78	88	92	84
NGL Fractionation (MBbl/d)	60	95	105	80
Facilities Activities Total				
Avg. Capacity (MMBbls/Mo.) (1)	100	112	114	106
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.37	$ 0.34(2)	$ 0.40(2)	$ 0.37(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 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 and terminal 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 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 production at the wellhead 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 September 30, 2012 reflect the current market structure and for the last six months of 2012, reflect the seasonal, weather-related variations in NGL sales. Our second-half guidance reflects an expectation for less favorable crude oil market conditions than those experienced during the first half of the year as well as less favorable NGL market conditions than previously forecasted. 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, production declines, 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		
	Six Months Ended Jun 30, 2012	**Three Months Ending 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	806	820	825	814
NGL Sales	144	125	215	157
Waterborne cargos	2	—	—	1
	952	945	1,040	972
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 2.42	$ 1.22(1)	$ 1.35(1)	$ 1.84(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 $140 to $160 million for maintenance capital projects. During the first six months of 2012, we invested $511 million and $76 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	$160
· Spraberry Area Pipeline Projects	100
· Gardendale Gathering System (1)	90
· Rainbow II Pipeline	75
· Mississippian Lime Project	60
· PAA Natural Gas Storage (multiple projects)	58
· Rail Projects (2)	50
· Bakken North	50
· St. James Phase IV	40
· Yorktown Terminal Project	40
· BP NGL Acquisition Related Projects	30
· Cushing Terminal Expansion (3)	30
· Shafter Expansion	30
· Patoka Terminal Expansion (3)	25
· Other Projects (4)	312
	$1,150
Potential Adjustments for Timing / Scope Refinement (5)	- $50 + $100
Total Projected Expansion Capital Expenditures	$1,100 - $1,250
Maintenance Capital Expenditures	$140 - $160

(1) Includes pipeline, tankage and condensate stabilization.
(2) Excludes rail project associated with the Yorktown terminal project.
(3) Includes carryover capital from 2011 expansions previously shown as “Other” 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 June 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 contango-related borrowings as carrying costs of crude oil and include it in purchases and related costs.

7. *Income Taxes*. We expect Canadian income tax expense/(benefit) to be approximately $0 million and $46 million for the three-month and twelve-month periods ending September 30, 2012 and December 31, 2012, respectively, of which approximately $(1) million and $36 million, respectively, is classified as current. For the twelve-month period ending December 31, 2012 we expect to have a deferred tax expense of $10 million. All or part of the income tax expense of $46 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 period ending September 30, 2012 and the three-month and twelve-month periods ending December 31, 2012.

	Mid-Point Guidance Three Months Ending Sep 30, 2012	Three Months Ending Dec 31, 2012	Twelve Months Ending Dec 31, 2012
		(in millions)	
Adjusted EBITDA	$ 410	$ 475	$ 1,880
Interest expense, net	(78)	(78)	(295)
Current income tax benefit (expense)	1	(14)	(36)
Distributions to noncontrolling interests	(12)	(12)	(48)
Maintenance capital expenditures	(37)	(37)	(150)
Other, net	1	1	1
Implied DCF	$ 285	$ 335	$ 1,352

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 August 5, 2012, estimated vesting dates range from August 2012 to May 2019 and annualized distribution levels range from $3.85 to $4.80. 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 July 9, 2012, we declared an annualized distribution of $4.26 payable on August 14, 2012 to our unitholders of record as of August 3, 2012. For the purposes of guidance, we have made the assessment that a $4.70 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of $86.00 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 $3.00 change in the unit price during the third-quarter would change the third-quarter equity compensation expense by approximately $3 million and the fourth-quarter equity compensation expense by less than $1 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 six-month period ended June 30. 2012, three-month period ending September 30, 2012 and three-month and twelve-month periods ending December 31, 2012.

	Actual 6 Months Ended Jun 30, 2012	Guidance 3 Months Ending Sep 30, 2012 Low	3 Months Ending Sep 30, 2012 High	3 Months Ending Dec 31, 2012 Low	3 Months Ending Dec 31, 2012 High	12 Months Ending Dec 31, 2012 Low	12 Months Ending Dec 31, 2012 High
			(in millions)				
Reconciliation to EBITDA							
Net Income	$ 624	$ 211	$ 261	$ 263	$ 312	$ 1,098	$ 1,197
Interest expense, net	140	79	76	79	76	298	292
Income tax expense (benefit)	30	2	(2)	17	14	49	42
EBIT	794	292	335	359	402	1,445	1,531
Depreciation and amortization	146	87	84	87	84	320	314
EBITDA	$ 940	$ 379	$ 419	$ 446	$ 486	$ 1,765	$ 1,845

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: August 6, 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
Strong Second-Quarter 2012 Results

(Houston — August 6, 2012) Plains All American Pipeline, L.P. (NYSE: PAA) today reported net income attributable to Plains of $378 million, or $1.85 per diluted limited partner unit, for the second quarter of 2012 as compared to $225 million, or $1.13 per diluted limited partner unit for the second quarter of 2011. The Partnership reported earnings before interest, taxes, depreciation and amortization ("EBITDA") of $557 million for the second quarter of 2012, compared to reported EBITDA of $367 million for the second quarter of 2011.

The Partnership's reported results include the impact of items that affect comparability between reporting periods. The impact of these items is excluded from adjusted results, as detailed in the table below. Accordingly, the Partnership's second-quarter 2012 adjusted net income attributable to Plains, adjusted net income per diluted limited partner unit and adjusted EBITDA were $343 million, $1.64 and $522 million, respectively. The comparable amounts for the second-quarter of 2011 were $224 million, $1.12 and $366 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.)

"PAA delivered outstanding second-quarter results with all three segments delivering strong performance," said Greg L. Armstrong, Chairman and CEO of Plains All American. "These results are reflective of PAA's strategically located assets, proven business model and solid execution during favorable market conditions."

Armstrong added, "Our distribution payable next week represents an 8.4% increase over last year's August distribution and we remain on track to increase our distribution by 8-9% during 2012. Demand for our assets and services remains strong and we have good visibility for continued growth. We have completed over $3 billion of acquisitions since the beginning of 2011, and we are on track to execute over $1 billion of organic growth projects during 2012. Additionally, PAA ended the quarter with a strong balance sheet, $2.8 billion of committed liquidity and favorably positioned with respect to each of its targeted credit metrics."

- more -

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Selected Items Impacting Comparability - Income / (Loss) (1):				
Inventory valuation adjustments net of gains from related derivative activities (2)	$ (5)	$ —	$ (5)	$ —
Gains from other derivative activities (2)	77	21	18	41
Equity compensation expense (3)	(12)	(20)	(38)	(33)
Net loss on early repayment of senior notes	—	—	—	(23)
Net loss on foreign currency revaluation	(16)	—	(16)	—
Significant acquisition-related expenses	(9)	—	(13)	(4)
Other (4)	—	—	—	1
Selected items impacting comparability of net income attributable to Plains	$ 35	$ 1	$ (54)	$ (18)
Less: GP 2% portion of selected items impacting comparability	(1)	—	1	—
Limited partners' 98% of selected items impacting comparability	$ 34	$ 1	$ (53)	$ (18)
Impact to basic net income per limited partner unit	$ 0.21	$ 0.02	$ (0.33)	$ (0.12)
Impact to diluted net income per limited partner unit	$ 0.21	$ 0.01	$ (0.33)	$ (0.12)

(1) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
(2) Gains from derivative activities related to revalued inventory are included in the line item "Inventory valuation adjustments net of gains from related derivative activities;" gains from derivative activities not related to revalued inventory are included in the line item "Gains from other derivative activities."
(3) Equity compensation expense for the three and six months ended June 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.
(4) 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 second quarter (amounts in millions):

	Three Months Ended June 30, 2012			Three Months Ended June 30, 2011		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues [1]	$ 361	$ 287	$ 9,442	$ 290	$ 164	$ 8,586
Purchases and related costs [1]	(35)	(65)	(9,030)	(31)	(20)	(8,330)
Field operating costs (excluding equity compensation expense) [1]	(128)	(86)	(105)	(106)	(43)	(73)
Equity compensation expense - operations	(3)	—	(1)	(2)	—	(1)
Segment G&A expenses (excluding equity compensation expense) [2]	(28)	(18)	(27)	(16)	(10)	(23)
Equity compensation expense - general and administrative	(7)	(4)	(5)	(11)	(5)	(8)
Equity earnings in unconsolidated entities	9	—	—	4	—	—
Reported segment profit	$ 169	$ 114	$ 274	$ 128	$ 86	$ 151
Selected items impacting comparability of segment profit [3]	11	5	(53)	9	5	(15)
Segment profit excluding selected items impacting comparability	$ 180	$ 119	$ 221	$ 137	$ 91	$ 136
Maintenance capital	$ 27	$ 10	$ 3	$ 17	$ 7	$ 3

	Six Months Ended June 30, 2012			Six Months Ended June 30, 2011		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues [1]	$ 678	$ 523	$ 18,319	$ 564	$ 325	$ 16,022
Purchases and related costs [1]	(63)	(139)	(17,638)	(54)	(43)	(15,535)
Field operating costs (excluding equity compensation expense) [1]	(224)	(133)	(207)	(196)	(83)	(141)
Equity compensation expense - operations	(10)	(1)	(1)	(5)	(1)	(1)
Segment G&A expenses (excluding equity compensation expense) [2]	(49)	(32)	(53)	(32)	(25)	(47)
Equity compensation expense - general and administrative	(16)	(14)	(18)	(17)	(9)	(13)
Equity earnings in unconsolidated entities	16	—	—	5	—	—
Reported segment profit	$ 332	$ 204	$ 402	$ 265	$ 164	$ 285
Selected items impacting comparability of segment profit [3]	21	15	17	15	13	(32)
Segment profit excluding selected items impacting comparability	$ 353	$ 219	$ 419	$ 280	$ 177	$ 253
Maintenance capital	$ 52	$ 17	$ 7	$ 35	$ 10	$ 7

(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 for the second quarter of 2012 increased by 31% over comparable 2011 results. This increase was primarily driven by acquisitions completed in late 2011 and early 2012 and higher average pipeline tariffs and volumes.

Adjusted segment profit for the Facilities segment for the second quarter of 2012 also increased by 31% over comparable 2011 results. This increase was primarily attributable to acquisitions completed in late 2011 and early 2012 and recently completed organic growth projects.

Adjusted segment profit for the Supply and Logistics segment for the second quarter of 2012 increased 63% over comparable 2011 results. This year-over-year improvement was driven by favorable crude oil market conditions and an increase in lease gathering margins and volumes.

The Partnership's basic weighted average units outstanding for the second quarter of 2012 totaled 162 million (163 million diluted) as compared to 149 million (150 million diluted) in last year's second quarter. On June 30, 2012, the Partnership had approximately 163 million units outstanding, long-term debt of approximately $5.8 billion and a long-term debt-to-total capitalization ratio of 47%.

The Partnership has declared a quarterly distribution of $1.065 per unit ($4.26 per unit on an annualized basis) payable August 14, 2012 on its outstanding limited partner units. This distribution represents an increase of approximately 8.4% over the quarterly distribution paid in August 2011 and an increase of approximately 1.9% over the quarterly distribution paid in May 2012.

The Partnership will hold a conference call at 11:00 AM (Eastern) on August 7, 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 third-quarter and full year 2012. 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. The primary measures used by management are 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 to 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.

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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.

Conference Call

The Partnership will host a conference call at 11:00 AM (Eastern) on Tuesday, August 7, 2012 to discuss the following items:

1. The Partnership's second-quarter 2012 performance;
2. The status of major expansion projects;
3. Capitalization and liquidity;
4. Financial and operating guidance for the third-quarter and full year 2012; and
5. 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 800-288-9626. International callers should dial 612-332-1025. 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 252212. The replay will be available beginning Tuesday, August 7, 2012, at approximately 1:00 PM (Eastern) and continue until 11:59 PM (Eastern) Friday, September 7, 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 also 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
(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
REVENUES	$ 9,786	$ 8,859	$ 19,004	$ 16,553
COSTS AND EXPENSES				
Purchases and related costs	8,830	8,202	17,332	15,281
Field operating costs	319	223	568	420
General and administrative expenses	89	73	182	143
Depreciation and amortization	86	63	146	126
Total costs and expenses	9,324	8,561	18,228	15,970
OPERATING INCOME	462	298	776	583
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	9	4	16	5
Interest expense	(75)	(62)	(140)	(128)
Other income/(expense), net	—	2	2	(20)
INCOME BEFORE TAX	396	242	654	440
Current income tax expense	(6)	(8)	(23)	(18)
Deferred income tax expense	(4)	(1)	(7)	(4)
NET INCOME	386	233	624	418
Less: Net income attributable to noncontrolling interests	(8)	(8)	(15)	(10)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 378	$ 225	$ 609	$ 408

NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 303	$ 170	$ 465	$ 299
GENERAL PARTNER	$ 75	$ 55	$ 144	$ 109
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.86	$ 1.14	$ 2.90	$ 2.04
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.85	$ 1.13	$ 2.88	$ 2.03
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	162	149	159	146
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	163	150	161	147

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

OPERATING DATA [1]	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Transportation activities (average daily volumes in thousands of barrels):				
Tariff activities				
All American	31	35	28	35
Basin	513	425	505	426
Capline	149	187	136	187
Line 63/Line 2000	130	122	124	108
Salt Lake City Area Systems [2]	147	138	138	137
Permian Basin Area Systems [2]	445	404	450	398
Mid-Continent Area Systems [2]	255	219	236	217
Manito	57	66	62	67
Rainbow	156	122	149	151
Rangeland	61	57	62	55
NGL	223	—	111	—
Refined products	118	97	115	97
Other	1,182	1,073	1,147	1,047
Tariff activities total	3,467	2,945	3,263	2,925
Trucking	96	104	102	101
Transportation activities total	3,563	3,049	3,365	3,026
Facilities activities (average monthly volumes):				
Crude oil, refined products and NGL storage (average monthly capacity in millions of barrels)	93	69	85	68
Natural gas storage (average monthly capacity in billions of cubic feet)	80	75	78	67
NGL fractionation (average throughput in thousands of barrels per day)	108	15	60	13
Facilities activities total (average monthly capacity in millions of barrels) [3]	109	82	100	80
Supply and Logistics activities (average daily volumes in thousands of barrels):				
Crude oil lease gathering purchases	814	722	806	722
NGL sales	153	65	144	108
Waterborne cargos	4	31	2	28
Supply and Logistics activities total	971	818	952	858

(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 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)

	June 30, 2012	December 31, 2011
ASSETS		
Current assets	$ 4,676	$ 4,351
Property and equipment, net	9,244	7,740
Goodwill	2,112	1,854
Linefill and base gas	645	564
Long-term inventory	291	135
Investments in unconsolidated entities	193	191
Other, net	645	546
Total assets	$ 17,806	$ 15,381
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 4,814	$ 4,511
Senior notes, net of unamortized discount	5,510	4,262
Long-term debt under credit facilities and other	283	258
Other long-term liabilities and deferred credits	554	376
Total liabilities	11,161	9,407
Partners' capital excluding noncontrolling interests	6,135	5,450
Noncontrolling interests	510	524
Total partners' capital	6,645	5,974
Total liabilities and partners' capital	$ 17,806	$ 15,381

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

CREDIT RATIOS
(in millions)

	June 30, 2012	December 31, 2011
Short-term debt	$ 997	$ 679
Long-term debt	5,793	4,520
Total debt	$ 6,790	$ 5,199
Long-term debt	5,793	4,520
Partners' capital	6,645	5,974
Total book capitalization	$ 12,438	$ 10,494
Total book capitalization, including short-term debt	$ 13,435	$ 11,173
Long-term debt-to-total book capitalization	47%	43%
Total debt-to-total book capitalization, including short-term debt	51%	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
(in millions, except per unit data)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Basic Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 378	$ 225	$ 609	$ 408
Less: General partner's incentive distribution [(1)]	(69)	(52)	(134)	(103)
Less: General partner 2% ownership [(1)]	(6)	(3)	(10)	(6)
Net income available to limited partners	303	170	465	299
Less: Undistributed earnings allocated and distributions to participating securities [(1)]	(2)	—	(3)	—
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 301	$ 170	$ 462	$ 299
Basic weighted average number of limited partner units outstanding	162	149	159	146
Basic net income per limited partner unit	$ 1.86	$ 1.14	$ 2.90	$ 2.04
Diluted Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 378	$ 225	$ 609	$ 408
Less: General partner's incentive distribution [(1)]	(69)	(52)	(134)	(103)
Less: General partner 2% ownership [(1)]	(6)	(3)	(10)	(6)
Net income available to limited partners	303	170	465	299
Less: Undistributed earnings allocated and distributions to participating securities [(1)]	(1)	—	(2)	—
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 302	$ 170	$ 463	$ 299
Basic weighted average number of limited partner units outstanding	162	149	159	146
Effect of dilutive securities:				
Weighted average LTIP units [(2)]	1	1	2	1
Diluted weighted average number of limited partner units outstanding	163	150	161	147
Diluted net income per limited partner unit	$ 1.85	$ 1.13	$ 2.88	$ 2.03

(1) 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.

(2) 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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FINANCIAL DATA RECONCILIATIONS
(in millions)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net income to earnings before interest, taxes, depreciation and amortization ("EBITDA") and excluding selected items impacting comparability ("Adjusted EBITDA") reconciliations				
Net Income	$ 386	$ 233	$ 624	$ 418
Add: Interest expense	75	62	140	128
Add: Income tax expense	10	9	30	22
Add: Depreciation and amortization	86	63	146	126
EBITDA	$ 557	$ 367	$ 940	$ 694
Selected items impacting comparability of EBITDA [(1)]	(35)	(1)	55	20
Adjusted EBITDA	$ 522	$ 366	$ 995	$ 714

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

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Adjusted EBITDA to Implied Distributable Cash Flow ("DCF")				
Adjusted EBITDA	$ 522	$ 366	$ 995	$ 714
Interest expense	(75)	(62)	(140)	(128)
Maintenance capital	(40)	(27)	(76)	(52)
Current income tax expense	(6)	(8)	(23)	(18)
Equity earnings in unconsolidated entities, net of distributions	1	1	—	6
Distributions to noncontrolling interests (1)	(12)	(11)	(24)	(23)
Other	—	—	—	(1)
Implied DCF	$ 390	$ 259	$ 732	$ 498

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

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Cash flow from operating activities reconciliation				
EBITDA	$ 557	$ 367	$ 940	$ 694
Current income tax expense	(6)	(8)	(23)	(18)
Interest expense	(75)	(62)	(140)	(128)
Net change in assets and liabilities, net of acquisitions	(466)	(6)	(489)	378
Other items to reconcile to cash flows from operating activities:				
Equity compensation expense	20	27	60	46
Net cash provided by operating activities	$ 30	$ 318	$ 348	$ 972

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

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

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net income and earnings per limited partner unit excluding selected items impacting comparability				
Net income attributable to Plains	$ 378	$ 225	$ 609	$ 408
Selected items impacting comparability of net income attributable to Plains	(35)	(1)	54	18
Adjusted net income attributable to Plains	$ 343	$ 224	$ 663	$ 426
Basic Adjusted Net Income per Limited Partner Unit:				
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 301	$ 170	$ 462	$ 299
Limited partners' 98% of selected items impacting comparability	(34)	(1)	53	18
Adjusted limited partners' net income	$ 267	$ 169	$ 515	$ 317
Basic weighted average units outstanding	162	149	159	146
Basic adjusted net income per limited partner unit	$ 1.65	$ 1.12	$ 3.23	$ 2.16
Diluted Adjusted Net Income per Limited Partner Unit:				
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 302	$ 170	$ 463	$ 299
Limited partners' 98% of selected items impacting comparability	(34)	(1)	53	18
Adjusted limited partner' net income	$ 268	$ 169	$ 516	$ 317
Diluted weighted average units outstanding	163	150	161	147
Diluted adjusted net income per limited partner unit	$ 1.64	$ 1.12	$ 3.21	$ 2.15

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