PLAINS ALL AMERICAN PIPELINE LP
Form 8-K/A
May 07, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K/A

CURRENT REPORT

Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) **May 6, 2013**

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))

Explanatory Note

On May 6, 2013 Plains All American Pipeline, L.P. furnished a Current Report on Form 8-K. This amendment is being furnished to correct a typographical error contained in subsection C of Note 2 in the previously furnished report. The Supply and Logistics Segment Profit per Barrel ($/Bbl) Excluding Selected Items Impacting Comparability for the six month period ending December 31, 2013 should be $1.14 instead of $0.76 as stated in the previous Form 8-K. This amount has been corrected in this amended Form 8-K. There were no other changes made to the previous Form 8-K or the exhibits thereto.

Item 9.01. **Financial Statements and Exhibits**

(d) Exhibit 99.1 Press Release dated May 6, 2013

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 first quarter 2013 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 also providing second quarter and second half of 2013 detailed guidance for financial performance. 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 Second Quarter and Second Half 2013 Guidance

We based our guidance for the three-month period ending June 30, 2013 and six-month and twelve-month periods ending December 31, 2013 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 May 5, 2013. We undertake no obligation to publicly update or revise any forward-looking statements.

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 9 below, we reconcile net income to EBIT and EBITDA for the 2013 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, within our guidance, we have highlighted the impact of (i) equity compensation expense, (ii) tax effect on selected items impacting comparability, (iii) net gain on foreign currency revaluation, (iv) gains from derivative activities and (v) other selected items impacting comparability. 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.

Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	Actual 3 Months Ended March 31, 2013	Guidance (a) 3 Months Ending June 30, 2013 Low	High	6 Months Ending December 31, 2013 Low	High	12 Months Ending December 31, 2013 Low	High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 1,194	$ 832	$ 860	$ 1,771	$ 1,813	$ 3,797	$ 3,867
Field operating costs	(340)	(343)	(335)	(676)	(664)	(1,359)	(1,339)
General and administrative expenses	(106)	(90)	(86)	(166)	(160)	(362)	(352)
	748	399	439	929	989	2,076	2,176
Depreciation and amortization expense	(82)	(87)	(82)	(178)	(173)	(347)	(337)
Interest expense, net	(77)	(82)	(77)	(169)	(164)	(328)	(318)
Income tax benefit (expense)	(53)	(7)	(2)	(23)	(18)	(83)	(73)
Other income, net		1	1	2	2	3	3
Net Income	**536**	**224**	**279**	**561**	**636**	**1,321**	**1,451**
Less: Net income attributable to noncontrolling interests	(8)	(6)	(6)	(17)	(17)	(31)	(31)
Net Income Attributable to Plains	**$ 528**	**$ 218**	**$ 273**	**$ 544**	**$ 619**	**$ 1,290**	**$ 1,420**
Net Income to Limited Partners (b)	$ 433	$ 126	$ 180	$ 344	$ 418	$ 903	$ 1,030
Basic Net Income Per Limited Partner Unit (b)							
Weighted Average Units Outstanding	336	340	340	342	342	340	340
Net Income Per Unit	$ 1.28	$ 0.37	$ 0.53	$ 1.00	$ 1.21	$ 2.64	$ 3.01
Diluted Net Income Per Limited Partner Unit (b)							
Weighted Average Units Outstanding	339	342	342	345	345	343	343
Net Income Per Unit	$ 1.27	$ 0.36	$ 0.52	$ 0.99	$ 1.21	$ 2.62	$ 2.99
EBIT	**$ 666**	**$ 313**	**$ 358**	**$ 753**	**$ 818**	**$ 1,732**	**$ 1,842**
EBITDA	**$ 748**	**$ 400**	**$ 440**	**$ 931**	**$ 991**	**$ 2,079**	**$ 2,179**
Selected Items Impacting Comparability							
Equity compensation expense	$ (24)	$ (15)	$ (15)	$ (25)	$ (25)	$ (64)	$ (64)
Tax effect on selected items impacting comparability	(5)					(5)	(5)
Net gain on foreign currency revaluation	8					8	8
Gains from derivative activities	24					24	24
Other	1			1	1	2	2
Selected Items Impacting Comparability of Net Income attributable to Plains	$ 4	$ (15)	$ (15)	$ (24)	$ (24)	$ (35)	$ (35)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 175	$ 180	$ 190	$ 440	$ 455	$ 795	$ 820
Facilities	156	135	145	294	309	585	610
Supply and Logistics	407	99	119	219	249	725	775
Other income, net	1	1	1	3	3	5	5
Adjusted EBITDA	$ 739	$ 415	$ 455	$ 956	$ 1,016	$ 2,110	$ 2,210

Adjusted Net Income Attributable to Plains	$	524	$	233	$	288	$	568	$	643	$	1,325	$	1,455
Adjusted Basic Net Income Per Limited Partner Unit (b)	$	1.27	$	0.41	$	0.57	$	1.07	$	1.28	$	2.74	$	3.11
Adjusted Diluted Net Income Per Limited Partner Unit (b)	$	1.26	$	0.41	$	0.56	$	1.06	$	1.27	$	2.72	$	3.10

(a) The projected average foreign exchange rate is $1.00 Canadian to $1.00 U.S. for the three-month period ending June 30, 2013 and the six-month period ending December 31, 2013. The rate as of May 3, 2013 was $1.00 Canadian to $0.99 U.S. A $0.05 change in the FX rate will impact annual adjusted EBITDA by approximately $14 million.

(b) 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
DCF	Distributable Cash Flow
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 Settoon Towing and the White Cliffs, Butte, Frontier and Eagle Ford pipeline systems, 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		
	Three Months Ended Mar 31, 2013	**Three Months Ending Jun 30, 2013**	**Six Months Ending Dec 31, 2013**	**Twelve Months Ending Dec 31, 2013**
Average Daily Volumes (MBbls/d)				
Crude Oil / Refined Products Pipelines				
All American	40	35	35	36
Bakken Area Systems	123	130	135	131
Basin/Mesa	725	700	710	711
Capline	156	160	150	154
Eagle Ford Area Systems	48	75	155	109
Line 63 / 2000	118	110	110	112
Manito	47	45	45	45
Mid-Continent Area Systems	268	270	275	272
Permian Basin Area Systems	477	545	635	574
Rainbow	122	125	125	124
Rangeland	67	60	65	64
Salt Lake City Area Systems	135	145	150	145
White Cliffs	22	20	25	23
Other	918	895	830	868
NGL Pipelines				
Co-Ed	57	55	60	58
Other	207	175	185	188
	3,530	3,545	3,690	3,614
Trucking	111	135	130	127
	3,641	3,680	3,820	3,741
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.53	$ 0.55[1]	$ 0.64[1]	$ 0.59[1]

(1) 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 and natural gas and condensate processing services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and redeliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (v) revenues from the sale of natural gas, (vi) fees from NGL fractionation and isomerization and (vii) fees from gas and condensate processing services. 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		
	Three Months Ended Mar 31, 2013	**Three Months Ending Jun 30, 2013**	**Six Months Ending Dec 31, 2013**	**Twelve Months Ending Dec 31, 2013**
Operating Data				

Crude Oil, Refined Products, and NGL Terminalling and Storage (MMBbls/Mo.)	94	95	95	95
Rail Unload / Load Volumes (MBbl/d)	216	250	340	287
Natural Gas Storage (Bcf/Mo.)	93	97	97	96
NGL Fractionation (MBbls/d)	100	95	105	101
Facilities Activities Total Avg. Capacity (MMBbls/Mo.) [1]	119	122	125	123
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.44	$ 0.38[2]	$ 0.40[2]	$ 0.40[2]

(1) Calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes, multiplied by the number of days in the period and divided by the number of months in the period; (iii) 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 (iv) NGL fractionation volumes, 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 merchant-related activities:

- the purchase of U.S. and Canadian 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 various delivery points, including but not limited to refineries, connecting carriers and fractionation facilities.

We characterize a substantial portion of our baseline 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 June 30, 2013 reflect the current market structure and for the six-month period ending December 31, 2013 reflect the 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 and quality differentials as well as contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Actual Three Months Ended Mar 31, 2013	Three Months Ending Jun 30, 2013	Guidance Six Months Ending Dec 31, 2013	Twelve Months Ending Dec 31, 2013
Average Daily Volumes (MBbl/d)				
Crude Oil Lease Gathering Purchases	857	880	930	900
NGL Sales	284	125	185	194
Waterborne Cargos	4	5	5	5
	1,145	1,010	1,120	1,099
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 3.95	$ 1.19[1]	$ 1.14[1]	$ 1.87[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 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 2013 to be approximately $1.4 billion for expansion projects with an additional $170 to $190 million for maintenance capital projects. During the first three months of 2013, we spent $358 million and $44 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, 2013:

	Calendar 2013 (in millions)
Expansion Capital	
• Mississippian Lime Pipeline	$180
• Rainbow II Pipeline	130
• Eagle Ford JV Project	95
• Rail Terminal Projects (1)	90
• White Cliffs Expansion	90
• Gulf Coast Pipeline	90
• Yorktown Terminal Projects	80
• Eagle Ford Area Pipeline Projects	75
• St. James Terminal Projects	55
• Cactus Pipeline	50
• PAA Natural Gas Storage (Multiple Projects)	42
• Spraberry Area Pipeline Projects	40
• Western Oklahoma Extension	40
• Shafter Expansion	25
• Cushing Terminal Projects	20
• Other Projects (2)	298
	$1,400
Potential Adjustments for Timing / Scope Refinement (3)	- $50 + $150
Total Projected Expansion Capital Expenditures	$1,350 - $1,550
Maintenance Capital Expenditures	$170 - $190

(1) Includes projects located at or near Tampa, CO, Bakersfield, CA, Carr, CO and Van Hook, ND.

(2) 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.

(3) 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 March 31, 2013 and adjusted for estimated equity issuances under our continuous offering program. Also assumed in our guidance is that we expect to repay our $250 million 5.625% senior notes that mature December 15, 2013 with short-term borrowings from our credit facility as a result of prefunding during 2012 (equity and retained cash flow), accordingly these notes are classified as short-term on our balance sheet at March 31, 2013.

6. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, estimated capital expenditures for maintenance and expansion projects, anticipated equity proceeds from the continuous offering program, 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 LIBOR curve as of late April.

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 our Canadian income tax expense to be approximately $5 million and $78 million for the three-month period ending June 30, 2013 and twelve-month period ending December 31, 2013, of which approximately $(1) million and $49 million, respectively, is classified as current income tax expense (benefit). For the twelve-month period ending December 31, 2013 we expect to have a deferred tax expense of $29 million. All or part of the income tax expense of $78 million may result in a tax credit to our equity holders.

8. *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 May 5, 2013, estimated vesting dates range from May 2013 to August 2019 and annualized benchmark distribution levels range from $1.925 to $2.85. 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 April 8, 2013, we declared an annualized distribution of $2.30 payable on May 15, 2013 to our unitholders of record as of May 3, 2013. For the purposes of guidance, we have made the assessment that a $2.50 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of $56.00 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 would change the second-quarter and full-year equity compensation expense by approximately $6 million and $7 million, respectively. Therefore, actual net income could differ from our projections.

9. *Reconciliation of Net Income to EBIT, EBITDA and Adjusted EBITDA.* The following table reconciles net income to EBIT, EBITDA and Adjusted EBITDA for the three-month period ending June 30, 2013 and the six and twelve-month periods ending December 31, 2013.

	Guidance					
	3 Months Ending June 30, 2013		6 Months Ending December 31, 2013		12 Months Ending December 31, 2013	
	Low	**High**	**Low**	**High**	**Low**	**High**
Reconciliation to EBITDA						
Net Income	$ 224	$ 279	$ 561	$ 636	$ 1,321	$ 1,451
Interest expense, net	82	77	169	164	328	318
Income tax expense	7	2	23	18	83	73
EBIT	313	358	753	818	1,732	1,842
Depreciation and amortization	87	82	178	173	347	337
EBITDA	$ 400	$ 440	$ 931	$ 991	$ 2,079	$ 2,179
Selected Items Impacting Comparability of EBITDA	15	15	25	25	31	31
Adjusted EBITDA	**$ 415**	**$ 455**	**$ 956**	**$ 1,016**	**$ 2,110**	**$ 2,210**

10. *Implied DCF*. The following table reconciles the mid-point of adjusted EBITDA to implied DCF for the three-month period ending June 30, 2013 and the six and twelve-month periods ending December 31, 2013.

	Three Months Ending June 30, 2013	Mid-Point Guidance Six Months Ending December 31, 2013 (in millions)	Twelve Months Ending December 31, 2013
Adjusted EBITDA	$ 435	$ 986	$ 2,160
Interest expense, net	(80)	(166)	(323)
Current income tax benefit (expense)	1	(4)	(49)
Distributions to noncontrolling interests	(13)	(26)	(51)
Maintenance capital expenditures	(45)	(91)	(180)
Implied DCF	$ 298	$ 699	$ 1,557

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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 st regarding our business strategy, plans and objectives for future operations. The absence of such 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:

- 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);
- 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;
- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;
- tightened capital markets or other factors that increase our cost of capital or limit our access to capital;
- 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;

- declines in the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our facilities, whether due to declines in production from existing oil and gas reserves, failure to or slowdown in the development of additional oil and gas reserves or other factors;

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

- 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;

- non-utilization of our assets and facilities;

- 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: May 7, 2013	By:	/s/ Charles Kingswell-Smith	
		Name:	Charles Kingswell-Smith
		Title:	*Vice President and Treasurer*