PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
August 06, 2014

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, 2014**

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, 2014

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 2014 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 detailed guidance for financial performance for the third and fourth quarters and full year 2014. 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 2014 Guidance; Update of Full Year 2014 Guidance

We based our guidance for the three-month period ending September 30, 2014 and three-month and twelve-month periods ending December 31, 2014 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 we can provide no assurance 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, 2014. 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 2014 guidance periods presented. Cash flows 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 forecasted periods. We encourage you to visit our website at *www.plainsallamerican.com* (in particular the section under Investor Relations entitled Guidance and Non-GAAP Reconciliations), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. 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. Due to the nature of the selected items, certain 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 6 Months Ended Jun 30, 2014	Guidance (a) 3 Months Ending Sep 30, 2014 Low	3 Months Ending Sep 30, 2014 High	3 Months Ending Dec 31, 2014 Low	3 Months Ending Dec 31, 2014 High	12 Months Ending Dec 31, 2014 Low	12 Months Ending Dec 31, 2014 High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 1,972	$ 903	$ 938	$ 1,013	$ 1,048	$ 3,888	$ 3,958
Field operating costs	(696)	(377)	(367)	(352)	(342)	(1,425)	(1,405)
General and administrative expenses	(179)	(85)	(80)	(83)	(78)	(347)	(337)
	1,097	441	491	578	628	2,116	2,216
Depreciation and amortization expense	(196)	(94)	(90)	(95)	(91)	(385)	(377)
Interest expense, net	(161)	(88)	(84)	(90)	(86)	(339)	(331)
Income tax expense	(70)	(8)	(4)	(38)	(34)	(116)	(108)
Other income / (expense), net	2					2	2
Net Income	**672**	**251**	**313**	**355**	**417**	**1,278**	**1,402**
Net income attributable to noncontrolling interests	(1)	(1)	(1)	(1)	(1)	(3)	(3)
Net Income Attributable to PAA	**$ 671**	**$ 250**	**$ 312**	**$ 354**	**$ 416**	**$ 1,275**	**$ 1,399**
Net Income to Limited Partners (b)	$ 435	$ 123	$ 184	$ 216	$ 279	$ 777	$ 898
Basic Net Income Per Limited Partner Unit (b)							
Weighted Average Units Outstanding	363	369	369	372	372	367	367
Net Income Per Unit	$ 1.19	$ 0.33	$ 0.49	$ 0.58	$ 0.75	$ 2.10	$ 2.43
Diluted Net Income Per Limited Partner Unit (b)							
Weighted Average Units Outstanding	365	372	372	374	374	369	369
Net Income Per Unit	$ 1.18	$ 0.33	$ 0.49	$ 0.58	$ 0.74	$ 2.09	$ 2.42
EBIT	**$ 903**	**$ 347**	**$ 401**	**$ 483**	**$ 537**	**$ 1,733**	**$ 1,841**
EBITDA	**$ 1,099**	**$ 441**	**$ 491**	**$ 578**	**$ 628**	**$ 2,118**	**$ 2,218**
Selected Items Impacting Comparability							
Equity-indexed compensation expense	$ (36)	$ (14)	$ (14)	$ (13)	$ (13)	$ (63)	$ (63)
Tax effect on selected items impacting comparability	(9)					(9)	(9)
Net gain / (loss) on foreign currency revaluation	6					6	6
Gains / (losses) from derivative activities, net of inventory valuation adjustments	50					50	50
Selected Items Impacting Comparability of Net Income attri−butable to PAA	$ 11	$ (14)	$ (14)	$ (13)	$ (13)	$ (16)	$ (16)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 443	$ 225	$ 235	$ 261	$ 271	$ 929	$ 949
Facilities	297	130	140	146	156	573	593
Supply and Logistics	338	100	130	184	214	622	682
Other income, net	1					1	1
Adjusted EBITDA	$ 1,079	$ 455	$ 505	$ 591	$ 641	$ 2,125	$ 2,225
Adjusted Net Income Attributable to PAA	$ 660	$ 264	$ 326	$ 367	$ 429	$ 1,291	$ 1,415
Basic Adjusted Net Income Per Limited Partner Unit (b)	$ 1.16	$ 0.36	$ 0.53	$ 0.62	$ 0.78	$ 2.14	$ 2.47
Diluted Adjusted Net Income Per Limited Partner Unit (b)	$ 1.15	$ 0.36	$ 0.53	$ 0.61	$ 0.78	$ 2.12	$ 2.46

(a) The assumed average foreign exchange rate is $1.10 Canadian to $1.00 U.S. for the six-month period ending December 31, 2014. The rate as of August 5, 2014 was $1.10 Canadian to $1.00 U.S. A $0.05 change in the FX rate will impact adjusted EBITDA for the six months ending December 31, 2014 by approximately $12 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
G&A	General and administrative
General partner (GP)	As the context requires, general partner or GP 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 and NGL on pipelines, gathering systems, trucks and barges. The Transportation segment generates 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 interests ranging from 22% to 50% and account for these under the equity method of accounting.

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 Six Months Ended Jun 30, 2014	Guidance Three Months Ending Sep 30, 2014	Guidance Three Months Ending Dec 31, 2014	Guidance Twelve Months Ending Dec 31, 2014
Average Daily Volumes (MBbls/d)				
Crude Oil Pipelines				
All American	36	35	35	35
Bakken Area Systems	138	155	160	148
Basin/Mesa	729	735	740	733
Capline	123	155	155	139
Eagle Ford Area Systems	199	230	260	222
Line 63 / 2000	116	120	145	124
Manito	44	45	45	45
Mid-Continent Area Systems	338	380	395	363
Permian Basin Area Systems	759	780	830	782
Rainbow	114	120	120	117
Rangeland	67	60	65	65
Salt Lake City Area Systems	131	140	130	133
South Saskatchewan	61	55	55	58
White Cliffs	24	25	35	27
Other	703	790	785	746
NGL Pipelines				
Co-Ed	56	55	60	57
Other	119	120	110	117
	3,757	4,000	4,125	3,911
Trucking	129	135	145	135
	3,886	4,135	4,270	4,046
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.63	$ 0.60(1)	$ 0.68(1)	$ 0.64(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. The Facilities segment generates 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) fees from NGL fractionation and isomerization, (v) fees from gas and condensate processing services and (vi) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing 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 Six Months Ended Jun 30, 2014	Guidance Three Months Ending Sep 30, 2014	Three Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
Operating Data				
Crude Oil, Refined Products, and NGL Terminalling and Storage (MMBbls/Mo.)	95	95	95	95
Rail Load / Unload Volumes (MBbls/d)	227	250	275	245
Natural Gas Storage (Bcf/Mo.)	97	97	97	97
NGL Fractionation (MBbls/d)	89	95	95	92
Facilities Activities Total Avg. Capacity (MMBbls/Mo.) (1)	121	122	123	121
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.41	$ 0.37(2)	$ 0.41(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 and natural gas;

- 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;

- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and ocean-going vessels from various delivery points, market hub locations or directly to end users such as refineries, processors and fractionation facilities; and

- the purchase and sale of natural gas.

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 G&A 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 market volatility as well as variable operating expenses. Forecasted operating results for the three-month period ending September 30, 2014 reflect the current market structure and forecasted operating results for the three and six month periods ending December 31, 2014 reflect seasonal and weather-related variations in NGL and natural gas sales. Our guidance is also based on an expectation that domestic crude oil production will continue to increase in line with increases over the last couple of years. 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 crude 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		**Guidance**	
	Six Months Ended Jun 30, 2014	**Three Months Ending Sep 30, 2014**	**Three Months Ending Dec 31, 2014**	**Twelve Months Ending Dec 31, 2014**
Average Daily Volumes (MBbls/d)				
Crude Oil Lease Gathering Purchases	912	965	995	946
NGL Sales	205	135	255	200
	1,117	1,100	1,250	1,146
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 1.67	$ 1.14(1)	$ 1.73(1)	$ 1.56(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, acceleration of depreciation 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 the calendar year of 2014 to be approximately $1.95 billion for expansion projects with an additional $185 to $205 million for maintenance capital projects. During the first six months of 2014, we spent $1,012 million and $95 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, 2014:

	Calendar 2014 (in millions)
Expansion Capital	
• Permian Basin Area Projects	$480
• Cactus Pipeline	350
• Rail Terminal Projects (1)	220
• Ft. Sask Facility Projects / NGL Line	135
• Western Oklahoma Extension	80
• Eagle Ford JV Project	65
• Mississippian Lime Pipeline	50
• White Cliffs Expansion	40
• Line 63 Reactivation	35
• Natural Gas Storage Expansions	35
• Other Projects	460
	$1,950

Potential Adjustments for Timing / Scope Refinement (2)	- \$100 + \$100
Total Projected Expansion Capital Expenditures	\$1,850 - \$2,050
Maintenance Capital Expenditures	\$185 - \$205

(1) Includes projects located in or near Bakersfield, CA, Carr, CO, Van Hook, ND and Kerrobert, Canada.

(2) 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, 2014 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, 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 July 2014.

Interest expense is net of amounts capitalized for major expansion capital projects and does not include interest on borrowings for hedged inventory. We treat interest on hedged inventory borrowings as carrying costs of crude oil, NGL, and natural gas and include it in purchases and related costs.

7. *Income Taxes*. We expect our Canadian income tax expense to be approximately $6 million and $112 million for the three-month period ending September 30, 2014 and twelve-month period ending December 31,2014, respectively, of which approximately $5 million and $88 million, respectively, is classified as a current income tax expense. For the twelve-month period ending December 31, 2014 we expect to have a deferred tax expense of $24 million. All or part of the annual income tax expense of $112 million may result in a tax credit to our equity holders.

8. *Equity-Indexed Compensation Plans.* The majority of grants outstanding under our various equity-indexed 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 6, 2014, estimated vesting dates range from August 2014 to August 2019 and annualized benchmark distribution levels range from $2.05 to $3.10. 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 8, 2014, we declared an annualized distribution of $2.58 payable on August 14, 2014 to our unitholders of record as of August 1, 2014. For the purposes of guidance, we have made the assessment that an annualized $2.85 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of $60 per unit as well as an accrual associated with awards that will vest on a certain date. The actual amount of equity-indexed 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) our then current probability assessment regarding distributions, and (iv) new equity-indexed compensation award grants, including the timing of such grant issuances. For example, a $2 change in the unit price would change the third-quarter and full year equity-indexed compensation expense by approximately $4 million. 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 six-month period ended June 30, 2014, three-month period ending September 30, 2014, and the three-month and twelve-month periods ending December 31, 2014.

	Actual		**Guidance**	
	6 Months	**3 Months Ending**	**3 Months Ending**	**12 Months Ending**

	Ended Jun 30, 2014	Sep 30, 2014 Low	Sep 30, 2014 High	Dec 31, 2014 Low (in millions)	Dec 31, 2014 High	Dec 31, 2014 Low	Dec 31, 2014 High
Reconciliation to EBITDA and Adjusted EBITDA							
Net Income	$ 672	$ 251	$ 313	$ 355	$ 417	$ 1,278	$ 1,402
Interest expense, net	161	88	84	90	86	339	331
Income tax expense	70	8	4	38	34	116	108
EBIT	903	347	401	483	537	1,733	1,841
Depreciation and amortization	196	94	90	95	91	385	377
EBITDA	$ 1,099	$ 441	$ 491	$ 578	$ 628	$ 2,118	$ 2,218
Selected Items Impacting Comparability of EBITDA	(20)	14	14	13	13	7	7
Adjusted EBITDA	**$ 1,079**	**$ 455**	**$ 505**	**$ 591**	**$ 641**	**$ 2,125**	**$ 2,225**

10. *Implied DCF.* The following table reconciles adjusted EBITDA to implied DCF for the six-month period ended June 30, 2014, the three-month period ending September 30, 2014 and the three-month and twelve-month periods ending December 31, 2014.

	Actual Six Months Ended Jun 30, 2014	Three Months Ending Sep 30, 2014	Mid-Point Guidance Three Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
		(in millions)		
Adjusted EBITDA	$ 1,079	$ 480	$ 616	$ 2,175
Interest expense, net	(161)	(86)	(88)	(335)
Current income tax expense	(52)	(5)	(31)	(88)
Maintenance capital expenditures	(95)	(50)	(50)	(195)
Other, net	5	(3)	(1)	1
Implied DCF	$ 776	$ 336	$ 446	$ 1,558

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, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking 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 or outcomes to differ materially from the results or outcomes 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);

- 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 develop or slowdown in the development of additional oil and gas reserves or other factors;

- 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 occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;

- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;

- 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 currency exchange rate of the Canadian dollar;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- 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;
- shortages or cost increases of supplies, materials or labor;
- the effectiveness of our risk management activities;
- 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;
- 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;

- risks related to the development and operation of our facilities, including our ability to satisfy our contractual obligations to our customers at our 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, 2014	By:	/s/ Charles Kingswell-Smith Name: Charles Kingswell-Smith Title: *Vice President and Treasurer*