

PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
February 08, 2016

**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) **February 8, 2016**

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE
(State or other jurisdiction of
incorporation)

1-14569
(Commission File Number)

76-0582150
(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)

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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))
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Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated February 8, 2016

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 fourth-quarter and full-year 2015 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 of financial performance for the first quarter and full year of 2016. 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 First-Quarter and Full-Year 2016 Guidance

We based our guidance for the three-month period ending March 31, 2016 and twelve-month period ending December 31, 2016 on assumptions and estimates that we believe are reasonable, given our assessment of historical trends (modified for changes in market conditions, including an assumption that U.S. onshore oil production continues to decline in 2016 as well as a continuation of a competitive crude oil market), 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. In particular, in response to recent price fluctuations, many producers are still developing their 2016 capital plans and production forecasts and others are modifying previously disclosed plans, which adds a fairly significant element of uncertainty to our 2016 quarterly and annual guidance given the impact that producer capital activity and production levels can have on our performance. Please refer to information under the caption Forward-Looking Statements and Associated Risks on page 10. 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 in the following pages is given as of the date hereof, based on information known to us as of February 7, 2016. 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 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. EBITDA (as defined in Note 1 to the Operating and Financial Guidance table) is a non-GAAP financial measure. Net income represents one of the two most directly comparable GAAP measures to EBITDA. In Note 10, we reconcile net income to EBITDA and adjusted EBITDA for the 2016 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 EBITDA, because such reconciliations are impractical for forecasted periods. We encourage you to visit our website at

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www.plainsallamerican.com (in particular the section under and Financial Information entitled Non-GAAP Reconciliations within the Investor Relations tab), which presents a historical reconciliation of EBITDA as well as certain other commonly used non-GAAP and supplemental 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), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) 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, referred to as adjusted results, but not impact other non-GAAP financial measures. We consider an understanding of these selected items impacting comparability to be material to the evaluation of our operating results and prospects.

Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	3 Months Ending Mar 31, 2016		Guidance (a)		12 Months Ending Dec 31, 2016			
	Low	High	Low	High	Low	High		
Segment Profit								
Net revenues (including equity earnings in unconsolidated entities)	\$	934	\$	982	\$	3,717	\$	3,877
Field operating costs		(329)		(320)		(1,289)		(1,259)
General and administrative expenses		(74)		(71)		(283)		(273)
		531		591		2,145		2,345
Depreciation and amortization expense		(114)		(110)		(446)		(430)
Interest expense, net		(112)		(108)		(448)		(432)
Income tax expense		(33)		(29)		(114)		(98)
Other income / (expense), net								
Net Income		272		344		1,137		1,385
Net income attributable to noncontrolling interests		(1)		(1)		(5)		(5)
Net Income Attributable to PAA	\$	271	\$	343	\$	1,132	\$	1,380
Net income attributable to common unitholders								
(b)	\$	96	\$	167	\$	401	\$	644
Basic net income per common unit (b)								
Weighted average common units outstanding		398		398		398		398
Net income per common unit	\$	0.24	\$	0.42	\$	1.01	\$	1.62
Diluted net income per common unit(b)(c)								
Weighted average common units outstanding								
(c)		400		400		400		400
Net income per common unit	\$	0.24	\$	0.42	\$	1.00	\$	1.61
EBITDA	\$	531	\$	591	\$	2,145	\$	2,345
Selected items impacting comparability-income / (loss)								
Equity-indexed compensation expense	\$	(9)	\$	(9)	\$	(30)	\$	(30)
Selected items impacting comparability of net income attributable to PAA								
	\$	(9)	\$	(9)	\$	(30)	\$	(30)
Excluding selected items impacting comparability								
Adjusted segment profit								
Transportation	\$	242	\$	260	\$	1,140	\$	1,200
Facilities		139		151		595		635
Supply and Logistics		159		189		440		540
Other income / (expense), net								
Adjusted EBITDA	\$	540	\$	600	\$	2,175	\$	2,375
Adjusted net income attributable to PAA	\$	280	\$	352	\$	1,162	\$	1,410
Basic adjusted net income per common unit (b)	\$	0.26	\$	0.44	\$	1.08	\$	1.69
Diluted adjusted net income per common unit								
(b)(c)	\$	0.26	\$	0.44	\$	1.07	\$	1.68

(a) The assumed average foreign exchange rate is \$1.40 Canadian dollar (CAD) to \$1.00 U.S. dollar (USD) for the three-month period ending March 31, 2016 and the twelve month period ending December 31, 2016. The rate as of February 5, 2016 was \$1.39 CAD to \$1.00 USD. We do not anticipate that fluctuations in the foreign exchange rate will have a significant impact on aggregate reported financial results, but such fluctuations will result in variations between segments.

(b) We allocate Net Income Attributable to PAA among our Series A Preferred Unitholders, Common Unitholders and General Partner interest using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate Net Income Attributable to PAA 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, common unitholders and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

(c) Diluted net income per common unit is computed based on the weighted average number of common units outstanding plus the effect of dilutive potential units outstanding during the period using the two-class method, unless the effects of such units are anti-dilutive.

Notes and Significant Assumptions:

1. *Definitions.*

EBITDA	Earnings before interest, taxes and depreciation and amortization
Segment Profit	Net revenues (including equity earnings in unconsolidated entities, as applicable) less segment field operating costs and general and administrative expenses
DCF	Distributable cash flow
Bbls/d	Barrels per day
Mcf	Thousand cubic feet
Bcf	Billion cubic feet
LTIP	Long-term incentive plan
NGL	Natural gas liquids, including 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: Transportation, Facilities and 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 pipeline capacity agreements and other transportation fees. Our transportation segment also includes equity earnings from our investments in the entities that own BridgeTex, Caddo, Eagle Ford, Frontier, Saddlehorn, White Cliffs, and Butte pipeline systems as well as Settoon Towing, in which we own interests ranging from 22% to 50%. We account for these investments under the equity method of accounting.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and assumed completion of capital projects. Actual volumes will be influenced by maintenance schedules at refineries, drilling and completion activity levels, production trends, weather and other natural occurrences including hurricanes, changes in the quantity of inventory held in tanks, variations due to market structure and other external factors beyond our control. We forecast adjusted segment profit using the volume assumptions following in the table, 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, as well as the extent of any cash we receive with respect to minimum ship or pay commitments for which revenue recognition is required to be deferred until the associated transportation credits are used or expire. The following table summarizes our total transportation volumes and broken down by crude oil geographic area as well as total NGL and trucking volumes.

	Guidance	
	Three Months Ending Mar 31, 2016	Twelve Months Ending Dec 31, 2016
Average daily volumes (MBbls/d)		
Volumes from tariff activities		
Crude oil pipelines (by region):		
Permian Basin (1)	2,125	2,380
South Texas / Eagle Ford (1)	320	340
Western	180	230
Rocky Mountain (1)	435	470
Gulf Coast	580	470
Central	360	405
Canada	395	410
Crude oil pipelines	4,395	4,705
NGL pipelines	165	155
Total volumes from tariff activities	4,560	4,860
Trucking	115	120
Total Transportation segment volumes	4,675	4,980
Adjusted segment profit per barrel (\$/Bbl)	\$ 0.59(2)	\$ 0.64(2)

- (1) Area systems include volumes (attributable to our interest) from pipelines owned by unconsolidated entities.
- (2) Represents the midpoint 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 agreements and processing arrangements.

Revenues generated in this segment primarily include (i) fees that are generated from storage capacity agreements, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and deliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) fees from NGL fractionation and isomerization services, (v) fees from natural gas and condensate processing services and (vi) 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 following table, priced at forecasted rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation.

	Three Months Ending Mar 31, 2016	Guidance	Twelve Months Ending Dec 31, 2016
Operating Data			
Crude oil, refined products and NGL terminalling and storage capacity (MMBbls/Mo.)	105		105
Rail load / unload volumes (MBbls/d)	115		150
Natural gas storage capacity (Bcf/Mo.)	97		97
NGL fractionation volumes (MBbls/d)	110		110
Total Facilities segment volumes			
Avg. Capacity (MMBbls/Mo.) (1)	128		129
Adjusted segment profit per barrel (\$/Bbl)	\$ 0.38(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 working capacity divided by 6 to account for the 6:1 mcf of natural 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) Represents the 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;
- 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 and carrying costs for hedged inventory 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 March 31, 2016 and for the twelve-month period ending December 31, 2016 reflect current market structure as well as seasonal, and weather-related and other anticipated variations in crude oil, NGL and natural gas 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 hedged 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 adjusted segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Guidance	
	Three Months Ending Mar 31, 2016	Twelve Months Ending Dec 31, 2016
Average daily volumes (MBbls/d)		
Crude oil lease gathering purchases	915	935
NGL sales	300	250
Total Supply and Logistics segment volumes	1,215	1,185
Adjusted segment profit per barrel (\$/Bbl)	\$ 1.57 ⁽¹⁾	\$ 1.13 ⁽¹⁾

(1) Represents the 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 also 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 calendar year 2016 to be approximately \$1.5 billion for expansion projects with an additional \$190 million to \$210 million for maintenance capital projects. The following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2016:

	Calendar 2016 (in millions)
Expansion Capital	
• Red River Pipeline (Cushing to Longview)	\$290
• Diamond Pipeline	260
• Permian Basin Area Pipeline Projects	185
• Fort Saskatchewan Facility Projects	190
• Saddlehorn Pipeline	155
• Cushing Terminal Expansions	35
• St. James Terminal Expansions	35
• Caddo Pipeline	30
• Cactus Pipeline	20
• Eagle Ford JV Project	20

• Other Projects	280	
	\$1,500	
Potential Adjustments for Timing / Scope Refinement (1)	- \$100	+ \$100
Total Projected Expansion Capital Expenditures	\$1,400	- \$1,600
Maintenance Capital Expenditures	\$190	- \$210

(1) Potential variation to current capital costs estimates may result from (i) changes to project design, (ii) final cost of materials and labor and (iii) timing of incurrence of costs due to uncontrollable factors such as receipt of permits, or regulatory approvals and weather.

5. *Asset Sales.* This guidance takes into account the sale of non-core assets for total proceeds of \$200 million to \$400 million which are assumed to close mid-year 2016. We do not expect that in the aggregate any gain or loss from these asset sales will be material and thus, we have not included any such estimate in our guidance.

6. *Capital Structure.* This guidance is based on our capital structure as of December 31, 2015, adjusted for the issuance of approximately 61 million Series A Convertible Preferred Units for net proceeds of approximately \$1.6 billion which closed late January 2016.

7. *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 January 2016.

Interest expense is net of amounts capitalized for 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.

8. *Income Taxes.* We expect our Canadian income tax expense to be approximately \$31 million and \$106 million for the three-month period ending March 31, 2016 and twelve-month period ending December 31, 2016, respectively, of which approximately \$23 million and \$80 million, respectively, is classified as a current income tax expense. For the twelve-month period ending December 31, 2016 we expect to have a deferred tax expense of \$26 million. All or part of the annual income tax expense of \$106 million may result in a tax credit to our equity holders.

9. *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 February 7, 2016, estimated vesting dates range from May 2016 to August 2024 and annualized benchmark distribution levels range from \$2.075 to \$3.50.

On January 12, 2016, we declared an annualized distribution of \$2.80 per unit payable on February 12, 2016 to our unitholders of record as of January 29, 2016. We have made the assessment that an annualized \$2.90 distribution level is probable in the reasonably foreseeable future, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of \$23 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 first-quarter equity-indexed compensation expense by approximately \$4 million and the full year equity-indexed compensation expense by approximately \$5 million. Therefore, actual net income could differ from our projections.

10. *Reconciliation of Net Income to EBITDA and Adjusted EBITDA.* The following table reconciles net income to EBITDA and Adjusted EBITDA for the indicated periods.

	3 Months Ending Mar 31, 2016		Guidance		12 Months Ending Dec 31, 2016	
	Low	High	Low	High	Low	High
Reconciliation to EBITDA and Adjusted EBITDA						
Net income	\$ 272	\$ 344	\$ 1,137	\$ 1,385		
Interest expense, net	112	108	448	432		
Income tax expense	33	29	114	98		
Depreciation and amortization	114	110	446	430		
EBITDA	\$ 531	\$ 591	\$ 2,145	\$ 2,345		
Selected items impacting comparability of EBITDA	9	9	30	30		
Adjusted EBITDA	\$ 540	\$ 600	\$ 2,175	\$ 2,375		

11. *Implied DCF*. The following table reconciles adjusted EBITDA to implied DCF for the indicated periods.

	Mid-Point Guidance	
	Three Months Ending Mar 31, 2016	Twelve Months Ending Dec 31, 2016
Adjusted EBITDA	\$ 570	\$ 2,275
Interest expense (1)	(106)	(423)
Maintenance capital expenditures	(50)	(200)
Current income tax expense	(23)	(80)
Other, net	3	14
Implied DCF	\$ 394	\$ 1,586

(1) Excludes non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

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 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:

- 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 assets, 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, whether from reduced cash flow to fund drilling or the inability to access capital, or other factors;
- the effects of competition;
- failure to implement or capitalize, or delays in implementing or capitalizing, on expansion 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;
- 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;
- tightened capital markets or other factors that increase our cost of capital or limit 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 currency exchange rate of the Canadian dollar;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- non-utilization of our assets and facilities;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- 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;
- increased costs, or lack of availability, of insurance;
- the effectiveness of our risk management activities;
- shortages or cost increases of supplies, materials or labor;
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;

- 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 assets, including our ability to satisfy our contractual obligations to our customers;
- inability to recognize current revenue attributable to deficiency payments received from customers who fail to ship or move more than minimum contracted volumes until the related credits expire or are used;
- 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: February 8, 2016

By: /s/ Sharon Spurlin
Name: Sharon Spurlin
Title: *Vice President and Treasurer*