PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
May 04, 2011

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) **May 4, 2011**

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 May 4, 2011.

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 2011 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. We are providing detailed guidance for financial performance for the second quarter and second half of calendar 2011. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under this 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 2011 Guidance

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as non-GAAP financial measures in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. EBIT and EBITDA (each as defined below in Note 1 to the Operating and Financial Guidance table) are non-GAAP financial measures. Net income represents one of the two most directly comparable GAAP measures to EBIT and EBITDA. In Note 10 below, we reconcile net income to EBIT and EBITDA for the 2011 guidance periods presented. Cash flow from operating activities is the other most comparable GAAP measure. We do not, however, reconcile cash flows from operating activities to EBIT and EBITDA, because such reconciliations are impractical for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled Non-GAAP Reconciliations), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. In addition, we have highlighted the impact of (i) equity compensation expense, (ii) gains from other derivative activities, (iii) net loss on early repayment of senior notes, (iv) insurance deductible related to property damage incident, (v) significant acquisition related expenses, and (vi) noncontrolling interest portion of selected items impacting comparability, as such items affect Segment Profit, EBITDA, Net Income attributable to Plains and Net Income per Basic and Diluted Limited Partner Unit.

We based our guidance for the three-month period ending June 30, 2011 and the six-month and twelve-month period ending December 31, 2011 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 LPG 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 3, 2011. We undertake no obligation to publicly update or revise any forward-looking statements.

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Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	Actual	**Guidance (1)**					
	3 Months Ended 3/31/2011	**3 Months Ending June 30, 2011 Low**	**3 Months Ending June 30, 2011 High**	**6 Months Ending December 31, 2011 Low**	**6 Months Ending December 31, 2011 High**	**12 Months Ending December 31, 2011 Low**	**12 Months Ending December 31, 2011 High**
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 615	$ 559	$ 581	$ 1,140	$ 1,159	$ 2,314	$ 2,355
Field operating costs	(197)	(218)	(212)	(410)	(403)	(825)	(812)
General and administrative expenses	(70)	(65)	(63)	(120)	(116)	(255)	(249)
	348	276	306	610	640	1,234	1,294
Depreciation and amortization expense	(63)	(64)	(61)	(127)	(123)	(254)	(247)
Interest expense, net	(65)	(65)	(62)	(133)	(128)	(263)	(255)
Income tax benefit (expense)	(13)	(8)	(6)	(12)	(10)	(33)	(29)
Other income (expense), net	(22)	1	1	3	3	(18)	(18)
Net Income	**185**	**140**	**178**	**341**	**382**	**666**	**745**
Less: Net income attributable to noncontrolling interests	(3)	(7)	(5)	(17)	(14)	(27)	(22)
Net Income attributable to Plains	**$ 182**	**$ 133**	**$ 173**	**$ 324**	**$ 368**	**$ 639**	**$ 723**
Net Income to Limited Partners	$ 133	$ 81	$ 120	$ 213	$ 257	$ 427	$ 510
Basic Net Income Per Limited Partner Unit (2)							
Weighted Average Units Outstanding	143	149	149	149	149	148	148
Net Income Per Unit	$ 0.90	$ 0.53	$ 0.79	$ 1.41	$ 1.70	$ 2.83	$ 3.40
Diluted Net Income Per Limited Partner Unit (2)							
Weighted Average Units Outstanding	144	150	150	150	150	148	148
Net Income Per Unit	$ 0.90	$ 0.53	$ 0.79	$ 1.41	$ 1.69	$ 2.81	$ 3.36
EBIT	**$ 263**	**$ 213**	**$ 246**	**$ 486**	**$ 520**	**$ 962**	**$ 1,029**
EBITDA	**$ 326**	**$ 277**	**$ 307**	**$ 613**	**$ 643**	**$ 1,216**	**$ 1,276**
Selected Items Impacting Comparability							
Equity compensation expense	$ (14)	$ (13)	$ (13)	$ (19)	$ (19)	$ (46)	$ (46)
Gains from other derivative activities	20					20	20
Net loss on early repayment of senior notes	(23)					(23)	(23)
Insurance deductible related to property damage incident	(1)					(1)	(1)
Significant acquisition related expenses	(4)					(4)	(4)
Selected Items Impacting Comparability of EBITDA	(22)	(13)	(13)	(19)	(19)	(54)	(54)
Noncontrolling interest portion of Selected Items Impacting Comparability	2	1	1	1	1	4	4
Selected Items Impacting Comparability of Net Income attributable to Plains	$ (20)	$ (12)	$ (12)	$ (18)	$ (18)	$ (50)	$ (50)
Excluding Selected Items Impacting Comparability							

Adjusted Segment Profit							
Transportation	$ 143	$ 135	$ 139	$ 303	$ 309	$ 581	$ 591
Facilities	87	84	87	189	193	360	367
Supply and Logistics	117	70	93	137	157	324	367
Other income (expense), net	1	1	1	3	3	5	5
Adjusted EBITDA	$ 348	$ 290	$ 320	$ 632	$ 662	$ 1,270	$ 1,330
Adjusted Net Income attributable to Plains	$ 202	$ 145	$ 185	$ 342	$ 386	$ 689	$ 773
Adjusted Basic Net Income per Limited Partner Unit	$ 1.04	$ 0.61	$ 0.87	$ 1.53	$ 1.81	$ 3.17	$ 3.72
Adjusted Diluted Net Income per Limited Partner Unit	$ 1.03	$ 0.61	$ 0.87	$ 1.52	$ 1.81	$ 3.14	$ 3.69

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(1) The projected average foreign exchange rate is $1.0 Canadian dollar to $1 U.S. Dollar for the three month period ending June 30, 2011 and $1.05 Canadian dollar to $1 U.S. Dollar for the six month period ending December 31, 2011. The rate as of May 3, 2011 was $0.95 Canadian dollar to $1 U.S. Dollar. A $0.05 change in the FX rate will impact annual EBITDA by approximately $10 million.

(2) Net income per unit has been calculated in accordance with FASB s requirement that the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter, be utilized within the earnings per unit calculation.

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
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other natural gas-related petroleum products (primarily propane and butane)
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 and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in the Butte, Frontier and White Cliffs pipeline systems and Settoon Towing, in which we own non-controlling interests.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and assumed completion of internal growth projects. Actual volumes will be influenced by maintenance schedules at refineries, production declines, 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 pipeline volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

	Actual Three Months Ended Mar 31, 2011	Three Months Ending Jun 30, 2011	Guidance Six Months Ending Dec 31, 2011	Twelve Months Ending Dec 31, 2011
Average Daily Volumes (000 Bbls/d)				
All American	35	37	38	37
Basin	427	400	400	407
Capline	188	190	190	190
Line 63 / 2000	94	100	100	97
Salt Lake City Area Systems (1)	136	140	140	139
Permian Basin Area Systems (1)	392	400	410	404
Manito	67	60	60	62
Rainbow	179	185	140	162
Rangeland	54	50	55	54
Refined Products	97	120	115	112
Other	1,235	1,288	1,297	1,278
	2,904	2,970	2,945	2,942
Trucking	99	100	105	102
	3,003	3,070	3,050	3,044
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability (2)	$ 0.53	$ 0.49(2)	$ 0.55(2)	$ 0.53(2)

(1) The aggregate of multiple systems in their respective areas.

(2) Mid-point of guidance.

b. *Facilities*. Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, LPG and natural gas, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

Adjusted segment profit is forecast 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 Three Months Ended Mar 31, 2011	Three Months Ending Jun 30, 2011	Guidance Six Months Ending Dec 31, 2011	Twelve Months Ending Dec 31, 2011
Operating Data				
Crude oil, refined products and LPG storage (MMBbls/Mo.)	67	69	72	70
Natural Gas Storage (Bcf/Mo.)	59	75	76	72
LPG Processing (MBbl/d)	11	11	11	11
Facilities Activities Total (1)				
Avg. Capacity (MMBbls/Mo.)	77	82	85	82
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability (2)	$ 0.37	$ 0.35(2)	$ 0.38(2)	$ 0.37(2)

(1) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by the gas to crude Btu equivalent ratio of 6 mcf of gas to 1 barrel of crude oil; and (iii) LPG processing 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 activities:

- the purchase of crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;

- the storage of inventory during contango market conditions and the seasonal storage of LPG;

- the purchase of refined products and LPG from producers, refiners and other marketers;

- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and

- the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

The level of profit 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, 2011 reflect the current market structure and, for the last nine months of 2011, reflect the seasonal, weather-related variations in LPG 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, production declines, weather, and other external factors beyond our control. Field operating costs do not include depreciation. Realized unit margins for any given lease-gathered barrel could vary significantly based on a variety of factors including location, quality and contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Actual		**Guidance**	
	Three Months Ended Mar 31, 2011	**Three Months Ending Jun 30, 2011**	**Six Months Ending Dec 31, 2011**	**Twelve Months Ending Dec 31, 2011**
Average Daily Volumes (MBbl/d)				
Crude Oil Lease Gathering Purchases	723	750	750	744
LPG Sales	151	70	120	115
Waterborne foreign crude oil imported	26	30	40	34
	900	850	910	893
Segment Profit per Barrel ($/Bbl)				

Excluding Selected Items Impacting Comparability (1)	$ 1.46	$ 1.05(1)	$ 0.88(1)	$ 1.06(1)

(1) Mid-point of guidance

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

4. *Acquisitions and Other Capital Expenditures.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions to which we may commit after the date hereof. We forecast capital expenditures during calendar 2011 to be approximately $600 million for expansion projects with an additional $90 million for maintenance capital projects. During the first three months of 2011, we spent

$97 million and $24 million, respectively, for expansion and maintenance projects. Following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2011:

		Calendar 2011 (in millions)
Expansion Capital		
• PAA Natural Gas Storage (multiple projects)	$	103
• Cushing - Phases IX - XI		61
• Basile Gas Processing Facility		36
• Ross (Stanley) Rail Project		35
• Undisclosed		30
• Shafter Expansion		25
• Bumstead Facility		22
• Undisclosed		20
• Nipisi Treater		18
• Mid-Continent Project		17
• Patoka Phase IV		17
• Ridgelawn (Sidney) Propane Storage		13
• Basin System Expansion		12
• Other projects (1)		191
		600
Maintenance Capital		90
Total Projected Capital Expenditures (excluding acquisitions)	$	690

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2010.

5. *Capital Structure.* This guidance is based on our capital structure as of March 31, 2011.

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

Included in interest expense are commitment fees, amortization of long-term debt discounts or premiums, deferred amounts associated with terminated interest-rate hedges and interest on short-term debt for non-contango inventory (primarily hedged LPG inventory and New York Mercantile Exchange and IntercontinentalExchange margin deposits). Interest expense is net of amounts capitalized for major expansion capital projects and does not include interest on borrowings for inventory stored in a contango market. We treat interest on contango-related borrowings as carrying costs of crude oil and include it in purchases and related costs.

7. *Income Taxes*. Effective January 1, 2011, our Canadian entities that were previously pass-through entities for Canadian tax purposes became taxpaying entities. For U.S. tax purposes, these entities will continue to be treated as pass-through entities. As a result of this and other organizational modifications related to this event, we expect our Canadian income tax expense to increase to approximately $31 million, of which approximately $27 million is classified as current taxes. In addition, withholding tax payments of approximately $10 million are estimated to be payable in 2011. Such withholding payments will reduce distributable cash flow, but will result in a tax credit to our equity

holders and will be reflected as a distribution in partners capital.

8. *Reconciliation of Adjusted EBITDA to Implied DCF.* The following table reconciles the mid-point of adjusted EBITDA to implied distributable cash flow for the three-month period ending June 30, 2011 and the twelve-month period ending December 31, 2011.

	Mid-Point Guidance	
	Jun. 30, 2011	Dec. 31, 2011
Adjusted EBITDA	$ 305	$ 1,300
Interest expense, net	(64)	(259)
Cash income taxes	(6)	(27)
Withholding taxes		(10)
Distributions to non-controlling interests	(11)	(41)
Maintenance capital expenditures	(22)	(90)
Other, net	1	6
Implied DCF	**$ 203**	**$ 879**

9. *Equity Compensation Plans*. The majority of grants outstanding under our various equity compensation plans contain vesting criteria that are based on a combination of performance benchmarks and service period. 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 4, 2011, estimated vesting dates range from May 2011 to May 2019 and annualized distribution levels range from $3.50 to $4.80. For some awards, a percentage of any units remaining unvested as of a date certain will vest on such date and all others will be forfeited.

On April 11, 2011, we declared an annualized distribution of $3.88 payable on May 13, 2011 to our unitholders of record as of May 3, 2011. We have made the assessment that a $4.00 distribution level is probable of occurring, and accordingly, for grants that vest at annualized distribution levels of $4.00 or less, guidance includes an accrual over the applicable service period at an assumed market price of $64.00 per unit as well as an accrual associated with awards that will vest on a date certain. The actual amount of equity compensation expense amortization in any given period will be directly influenced by (i) our unit price at the end of each reporting period, (ii) our unit price on the vesting date (iii) the probability assessment regarding distributions, and (iv) new equity compensation award grants. For example, a $3.00 change in the unit price assumption at June 30, 2011 would change the second-quarter equity compensation expense by approximately $4 million and the second-half equity compensation expense by approximately $10 million. Therefore, actual net income could differ materially from our projections. Similarly, if an assessment was made that a $4.10 distribution level was probable, second-quarter equity compensation expense would increase by approximately $11 million (approximately $8 million for the cumulative effect of prior service periods and approximately $3 million for the current service period amortization). Additionally, compensation expense for the six months ending December 31, 2011 would increase approximately $7 million.

10. *Reconciliation of Net Income to EBIT and EBITDA.* The following table reconciles net income to EBIT and EBITDA, for the three-month guidance period ending June 30, 2011 and the six-month and twelve-month guidance periods ending December 31, 2011.

	Actual	Guidance					
	3 Months Ended	3 Months Ending June 30, 2011		6 Months Ending December 31, 2011		12 Months Ending December 31, 2011	
	Mar 31, 2011	Low	High	Low	High	Low	High
				(in millions, except per unit amounts)			
Reconciliation to EBITDA							
Net Income	$ 185	$ 140	$ 178	$ 341	$ 382	$ 666	$ 745
Interest expense	65	65	62	133	128	263	255
Income tax expense	13	8	6	12	10	33	29
EBIT	263	213	246	486	520	962	1,029
Depreciation and amortization	63	64	61	127	123	254	247
EBITDA	$ 326	$ 277	$ 307	$ 613	$ 643	$ 1,216	$ 1,276

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 these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- failure to implement or capitalize on planned internal growth projects;

- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;

- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

- the effectiveness of our risk management activities;

- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;

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

- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the 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;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;
- the effects of competition;
- interruptions in service on third-party pipelines;
- increased costs or lack of availability of insurance;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- the currency exchange rate of the Canadian dollar;

- weather interference with business operations or project construction;

- risks related to the development and operation of natural gas storage facilities;

- future developments and circumstances at the time distributions are declared;

- 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, refined products and liquefied petroleum gas and other natural gas related petroleum products.

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 4, 2011	By:	/s/ Charles Kingswell-Smith Name: Charles Kingswell-Smith Title: *Vice President and Treasurer*