PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
February 09, 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) **February 9, 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 February 9, 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 fourth-quarter and annual 2010 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 first quarter of calendar 2011 and for the full year. 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 First Quarter and Full Year 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 and cash flows from operating activities are the most directly comparable GAAP measures to EBIT and EBITDA. In Note 11 below, we reconcile net income to EBIT and EBITDA for the 2011 guidance periods presented. 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 our (i) equity compensation expense, (ii) net loss on early repayment of senior notes, and (iii) PAA Natural Gas Storage (PNG) insurance deductible for the Bluewater incident as well as SG Resources acquisition related costs, 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 March 31, 2011 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 February 8, 2011. We undertake no obligation to publicly update or revise any forward-looking statements.

On December 29, 2010 PAA announced that PAA Natural Gas Storage, L.P. (in which PAA has a general partner interest and majority equity ownership position) entered into a definitive agreement to acquire SG Resources Mississippi, LLC, (SG Resources). The primary asset of SG Resources is the Southern Pines Energy Center (Southern Pines) which is a FERC-regulated, high-performance, salt-cavern natural gas storage facility. These projections include the effect of the Southern Pines acquisition which closed on February 9, 2011 for total consideration of approximately $750 million.

Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	Guidance							
	3 Months Ending March 31, 2011				12 Months Ending December 31, 2011			
	Low		High		Low		High	
Segment Profit								
Net revenues (including equity earnings from unconsolidated entities)	$	521	$	543	$	2,154	$	2,199
Field operating costs		(190)		(184)		(773)		(755)
General and administrative expenses		(63)		(61)		(236)		(229)
		268		298		1,145		1,215
Depreciation and amortization expense		(55)		(52)		(231)		(222)
Interest expense, net		(70)		(67)		(269)		(262)
Income tax benefit (expense)		(8)		(6)		(22)		(18)
Other income (expense), net		(26)		(26)		(22)		(22)
Net Income	**$**	**109**	**$**	**147**	**$**	**601**	**$**	**691**
Less: Net income attributable to noncontrolling interests		(2)		(1)		(23)		(21)
Net Income attributable to Plains	**$**	**107**	**$**	**146**	**$**	**578**	**$**	**670**
Net Income to Limited Partners	$	60	$	98	$	376	$	466
Basic Net Income Per Limited Partner Unit								
Weighted Average Units Outstanding		141		141		141		141
Net Income Per Unit	$	0.42	$	0.69	$	2.62	$	3.26
Diluted Net Income Per Limited Partner Unit								
Weighted Average Units Outstanding		142		142		142		142
Net Income Per Unit	$	0.41	$	0.68	$	2.60	$	3.24
EBIT	**$**	**187**	**$**	**220**	**$**	**892**	**$**	**971**
EBITDA	**$**	**242**	**$**	**272**	**$**	**1,123**	**$**	**1,193**
Selected Items Impacting Comparability								
Equity compensation expense	$	(10)	$	(10)	$	(39)	$	(39)
PNG insurance deductible on Bluewater incident and Southern Pines acquisition related expenses		(5)		(5)		(5)		(5)
Net loss on early repayment of senior notes		(23)		(23)		(23)		(23)
	$	(38)	$	(38)	$	(67)	$	(67)
Excluding Selected Items Impacting Comparability								
Adjusted Segment Profit								
Transportation	$	138	$	143	$	585	$	598
Facilities		73		76		353		360
Supply and Logistics		68		90		247		297
Other income (expense), net		1		1		5		5
Adjusted EBITDA	$	280	$	310	$	1,190	$	1,260
Adjusted Net Income attributable to Plains	$	145	$	184	$	645	$	737
Adjusted Basic Net Income per Limited Partner Unit	$	0.68	$	0.95	$	3.08	$	3.72
Adjusted Diluted Net Income per Limited Partner Unit	$	0.67	$	0.94	$	3.06	$	3.70

(1) The projected average foreign exchange rate is $1.05 Canadian dollar to $1 U.S. Dollar. The rate as of February 8, 2011 was $0.99 Canadian dollar to $1 U.S. Dollar. A $0.05 change in the FX rate will impact annual EBITDA by approximately $10 million.

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.

	Guidance	
	Three Months Ended Mar 31, 2011	Twelve Months Ending Dec 31, 2011
Average Daily Volumes (000 Bbls/d)		
All American	38	38
Basin	380	395
Capline	200	200
Line 63 / 2000	105	105
Salt Lake City Area Systems (1)	135	145
Permian Basin Area Systems (1)	390	400
Rainbow	190	165
Manito	60	60
Rangeland	50	55
Refined Products	115	120
Other	1,237	1,262
	2,900	2,945
Trucking	100	105
	3,000	3,050
Segment Profit per Barrel ($/Bbl)		
Excluding Selected Items Impacting Comparability (2)	$ 0.52	$ 0.53

(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.

	Guidance	
	Three Months Ended Mar 31, 2011	Twelve Months Ending Dec 31, 2011
Operating Data		
Crude oil, refined products and LPG storage (MMBbls/Mo.)	66	68
Natural Gas Storage (Bcf/Mo.)	58	71
LPG Processing (MBbl/d)	10	10
Facilities Activities Total (1)		
Avg. Capacity (MMBbls/Mo.)	76	80
Segment Profit per Barrel ($/Bbl)		
Excluding Selected Items Impacting Comparability (2)	$ 0.33	$ 0.37

(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 March 31, 2011 reflect the current market structure and 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.

	Guidance	
	Three Months Ended Mar 31, 2011	**Twelve Months Ending Dec 31, 2011**
Average Daily Volumes (MBbl/d)		
Crude Oil Lease Gathering Purchases	700	715
LPG Sales	155	120
Waterborne foreign crude oil imported	40	40
	895	875
Segment Profit per Barrel ($/Bbl)		

Excluding Selected Items Impacting Comparability (1)	$ 0.98	$ 0.85

(1) Mid-point of guidance

3. *Depreciation and Amortization.* We forecast depreciation and amortization based on our existing depreciable assets, the Southern Pines acquisition, 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. This guidance reflects the full year benefit of a reduction in depreciation expense from the internal review initiated in 2010 that reassessed the depreciable lives of several of our large storage facilities and pipeline systems.

4. *Acquisitions and Other Capital Expenditures.* As stated above, this guidance includes the effect of the purchase of Southern Pines that closed on February 9, 2011. 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 $550 million for expansion projects with an additional $85 million for maintenance capital 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 Terminal Phases IX XI		62
• Basile gas processing facility		36
• Shafter Expansion		30
• Stanley Rail Project		25
• Bumstead Facility		21
• Mid-Continent project		17
• Nipisi Treater		17
• Patoka Phase IV		17
• Undisclosed		17
• Sidney Propane Storage		13
• Basin System expansion		11
• Other projects (1)		181
		550
Maintenance Capital		85
Total Projected Capital Expenditures (excluding acquisitions)	$	635

(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 December 31, 2011 adjusted for PNG s issuance of $370 million of equity prior to closing of the Southern Pines acquisition and PAA s issuance of $600 million of 5% 10-year senior notes on January 14, 2011. A portion of the new senior notes was used to fund the remainder of the Southern Pines purchase price and repurchase $200 million of 7.75% senior notes on February 7, 2011 (a $23 million loss associated with repurchasing these notes is reflected in Other Expenses and is considered a Selected Item Impacting Comparability). Also, in early January 2011, a $500 million, 364-day revolving credit facility was established.

6. *Interest Expense.* Debt balances are projected based on the change in capital structure discussed in Note 5, 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 will become 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 $20 million, of which approximately $17 million is classified as current taxes. In addition, withholding tax payments of approximately $12 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 and twelve-month mid-point guidance periods ending March 31, 2011 and December 31, 2011, respectively.

	Mid-Point Guidance	
	Mar. 31, 2011	**Dec. 31, 2011**
Adjusted EBITDA	$ 295	$ 1,225
Interest expense, net	(69)	(266)
Cash income taxes	(5)	(17)
Withholding taxes	(3)	(12)
Distributions to non-controlling interests	(5)	(40)
Maintenance capital expenditures	(21)	(85)
Other, net	3	5
Implied DCF	$ 195	$ 810

9. *Net Income per Unit.* Basic net income per limited partner unit is calculated by dividing net income allocated to limited partners by the basic weighted average units outstanding during the period.

	Guidance			
	3 Months Ending March 31, 2011		**12 Months Ending December 31, 2011**	
	Low	**High**	**Low**	**High**
	(in millions, except per unit amounts)			
Numerator for basic and diluted earnings per limited partner unit:				
Net Income attributable to Plains	$ 107	$ 146	$ 578	$ 670
Less: General partners incentive distribution paid (1)	(46)	(46)	(194)	(194)
Subtotal	61	100	384	476
Less: General partner 2% ownership (1)	(1)	(2)	(8)	(10)
Net income available to limited partners	60	98	376	466
Adjustment in accordance with application of the two-class method for MLPs (1)	(1)	(1)	(6)	(6)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 59	$ 97	$ 370	$ 460
Denominator:				
Basic weighted average number of limited partner units	141	141	141	141
Effect of dilutive securities:				
Weighted average LTIP units	1	1	1	1
Diluted weighted average number of limited partner units	142	142	142	142
Basic net income per limited partner unit	$ 0.42	$ 0.69	$ 2.62	$ 3.26

Diluted net income per limited partner unit	$	0.41	$	0.68	$	2.60	$	3.24

(1) We calculate net income to our general partner based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). However, FASB guidance requires 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. After adjusting for this distribution, the remaining undistributed earnings or excess distribution over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement for earnings per unit calculation purposes. We reflect the impact of the difference in (i) the distribution utilized and (ii) the calculation of the excess 2% general partner interest as the Adjustment in accordance with application of the two-class method for MLPs.

In conjunction with certain acquisitions, our general partner reduced the amounts due it as incentive distributions by an aggregate amount of $83 million. Approximately $76 million of this reduction was realized as of December 31, 2010. The remaining $7 million of incentive distribution reductions will be realized in 2011.

The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units. Based on the current number of units outstanding, each $0.05 per unit annual increase or decrease in the distribution relative to forecasted amounts decreases or increases net income available for limited partners by approximately $7 million ($0.05 per unit) on an annualized basis.

10. *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 February 9, 2011, estimated vesting dates range from May 2011 to May 2019 and annualized distribution levels range from $3.50 to $4.50. 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 January 12, 2011, we declared an annualized distribution of $3.83 payable on February 14, 2011 to our unitholders of record as of February 4, 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 $63.00 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 amount of the amortization in the early years, (iv) the probability assessment regarding distributions, and (v) new equity compensation award grants. For example, a $3.00 change in the unit price assumption at March 31, 2011 would change the first-quarter equity compensation expense by approximately $6 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, first-quarter equity compensation expense would increase by approximately $8 million (approximately $6 million for the cumulative effect of prior service periods and approximately $2 million for the current service period amortization). Compensation expense for the remaining nine months ending December 31, 2011 would increase approximately $6 million.

11. *Reconciliation of Net Income to EBIT and EBITDA.* The following table reconciles net income to EBIT and EBITDA, for the three-month and twelve-month guidance periods ending March 31, 2011 and December 31, 2011, respectively.

	Guidance			
	3 Months Ending March 31, 2011		12 Months Ending December 31, 2011	
	Low	High	Low	High
Reconciliation to EBITDA				
Net Income	$ 109	$ 147	$ 601	$ 691
Interest expense	70	67	269	262
Income tax expense	8	6	22	18
EBIT	187	220	892	971
Depreciation and amortization	55	52	231	222
EBITDA	$ 242	$ 272	$ 1,123	$ 1,193

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;