PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
August 06, 2008

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, 2008

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) Exhibits

Exhibit 99.1 Press Release dated August 6, 2008.

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 2008 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 providing detailed guidance for financial performance for the third and fourth quarter of calendar 2008 and updating our previous guidance for financial performance for the full calendar year of 2008 (which supersedes guidance pertaining to 2008 contained in our Form 8-K furnished on May 29, 2008). 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 Third and Fourth Quarter 2008 Guidance; Update of Full Year 2008 Guidance

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 10 below, we reconcile EBITDA and EBIT to net income for the 2008 guidance periods presented. It is, however, impractical to reconcile EBIT and EBITDA to cash flows from operating activities for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled Non-GAAP Reconciliation), which presents a historical reconciliation of certain commonly used non-GAAP financial measures, including EBIT and EBITDA. We present EBIT and EBITDA because we believe they provide additional information with respect to both the performance of our fundamental business activities and our ability to meet our future debt service, capital expenditures and working capital requirements. We also believe that debt holders commonly use EBITDA to analyze partnership performance. In addition, we have highlighted the impact of our equity compensation plans and, to the extent known, gains and losses related to SFAS 133 (primarily non-cash, mark-to-market adjustments) on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three months ending September 30 and December 31, 2008 and the twelve months ending December 31, 2008 is based 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 information reasonably available. 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 August 5, 2008. 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)					
	6 Months Ended 06/30/08	3 Months Ending September 30, 2008		3 Months Ending December 31, 2008		12 Months Ending December 31, 2008	
		Low	High	Low	High	Low	High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 702	$ 407	$ 421	$ 425	$ 443	$ 1,534	$ 1,566
Field operating costs	(297)	(168)	(164)	(159)	(154)	(624)	(615)
General and administrative expenses	(90)	(44)	(42)	(44)	(42)	(178)	(174)
	315	195	215	222	247	732	777
Depreciation and amortization expense	(100)	(54)	(52)	(57)	(56)	(211)	(208)
Interest expense, net	(91)	(52)	(50)	(53)	(52)	(196)	(193)
Income tax expense	(3)	(5)	(4)	(6)	(5)	(14)	(12)
Other income (expense), net	12					12	12
Net Income	**$ 133**	**$ 84**	**$ 109**	**$ 106**	**$ 134**	**$ 323**	**$ 376**
Net Income to Limited Partners	$ 83	$ 53	$ 77	$ 75	$ 101	$ 211	$ 261
Basic Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	118	123	123	123	123	120	120
Net Income Per Unit	$ 0.70	$ 0.43	$ 0.63	$ 0.61	$ 0.82	$ 1.76	$ 2.18
Diluted Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	119	124	124	124	124	124	121
Net Income Per Unit	$ 0.69	$ 0.43	$ 0.62	$ 0.60	$ 0.81	$ 1.74	$ 2.16
EBIT	**$ 227**	**$ 141**	**$ 163**	**$ 165**	**$ 191**	**$ 533**	**$ 581**
EBITDA	**$ 327**	**$ 195**	**$ 215**	**$ 222**	**$ 247**	**$ 744**	**$ 789**
Selected Items Impacting Comparability							
Equity compensation charge	$ (21)	$ (10)	$ (10)	$ (8)	$ (8)	$ (39)	$ (39)
Acquisition related hedging activity	11					11	11
SFAS 133 Mark-to-Market Adjustment	(92)					(92)	(92)
	$ (102)	$ (10)	$ (10)	$ (8)	$ (8)	$ (120)	$ (120)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 206	$ 111	$ 117	$ 117	$ 123	$ 434	$ 446
Facilities	71	40	42	41	45	152	158
Marketing	151	54	66	72	87	277	304
Other Income (Expense), net	1					1	1
Adjusted EBITDA	$ 429	$ 205	$ 225	$ 230	$ 255	$ 864	$ 909
Adjusted Net Income	$ 235	$ 94	$ 119	$ 114	$ 142	$ 443	$ 496
Adjusted Basic Net Income per Limited Partner Unit	$ 1.54	$ 0.51	$ 0.71	$ 0.67	$ 0.89	$ 2.74	$ 3.16
Adjusted Diluted Net Income per Limited Partner Unit	$ 1.53	$ 0.51	$ 0.70	$ 0.67	$ 0.88	$ 2.72	$ 3.13

(1) The projected average foreign exchange rate is $1 CAD to $1 USD. The rate as of August 5, 2008 was $1.04 CAD to $1 USD.

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 purchases, 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
FX	Foreign currency exchange
General partner	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.
Class B units	Class B units of Plains AAP, L.P.

2. *Business Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. 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. We also include in this segment our equity earnings from our investments in the Butte and Frontier pipeline systems, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Volumes are influenced by temporary market-driven storage and withdrawal of oil, maintenance schedules at refineries, production declines and other external factors beyond our control. Segment profit is forecast 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 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.

	Calender 2008			
	Actual		Guidance	
	Six Months Ended June 30	Three Months Ending September 30	Three Months Ending December 31	Twelve Months Ending December 31
Average Daily Volumes (000 Bbls/d)				
All American	45	46	46	45
Basin	370	360	360	365
Capline	218	245	235	229
Line 63 / 2000	161	150	150	155
Salt Lake City Area Systems (1)	96	95	100	97
West Texas / New Mexico Area Systems (1)	402	400	400	401
Rainbow	66	195	195	130
Manito	70	75	75	73
Rangeland	60	55	55	58
Refined Products	111	110	120	113
Other	1,206	1,184	1,189	1,199
	2,805	2,915	2,925	2,865
Trucking	93	105	110	101
	2,898	3,020	3,035	2,966
Average Segment Profit ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.39	$ 0.41(2)	$ 0.43(2)	$ 0.41(2)

(1) The aggregate of multiple systems in the 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 and LPG, 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. This segment also includes our equity earnings from our 50% investment in PAA/Vulcan Gas Storage, LLC, which owns and operates approximately 26 Bcf of underground natural gas storage capacity and is constructing an additional 24 Bcf of underground storage capacity.

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.

	Calendar 2008			
	Actual		Guidance	
	Six Months Ended June 30	Three Months Ending September 30	Three Months Ending December 31	Twelve Months Ending December 31, 2008
Operating Data				
Crude oil, refined products and LPG storage (MMBbls/Mo.)[1]	54	55	59	56
Natural Gas Storage (Bcf/Mo.)	13	13	14	14
LPG Processing (MBbl/d)	16	20	19	18
Facilities Activities Total [2]				
Avg. Capacity (MMBbls/Mo.)	57	58	62	58
Segment Profit per Barrel ($/Bbl)				
	$ 0.21	$ 0.24(3)	$ 0.23(3)	$ 0.22(3)

Excluding Selected Items Impacting Comparability

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(1) Effective with the second quarter of 2008, facilities segment volumes with respect to crude oil and refined products are reported based on total shell capacity to provide uniform comparisons with respect to our activities for these products. Previously, such volumes were reported based on a combination of shell capacity and working capacity depending on the terms of the third-party or intra-company lease agreements. Natural gas and LPG volumes, which consist primarily of underground storage facilities, reflect working capacity as that is the primary basis upon which such facilities are leased. Corresponding metrics for prior periods have been conformed to this uniform approach.

(2) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to barrel of crude oil ratio; and (iii) LPG processing volumes multiplied by the number of days in the period and divided by the number of months in the period.

(3) Mid-point of guidance.

c. *Marketing*. Our marketing segment operations generally consist of the following merchant activities:

- the purchase of U.S. and Canadian 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 marketing 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 remainder of 2008 reflect the assumption of a relatively flat crude oil market structure and weather-related seasonal variations in LPG sales. Unforecasted changes in market structure or volatility (or lack thereof) could cause actual results to differ materially from forecasted results.

We forecast 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. 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.

	Calendar 2008			
	Actual	Guidance		
	Six Months Ended June 30	Three Months Ending September 30	Three Months Ending December 31	Twelve Months Ending December 31, 2008
Average Daily Volumes (MBbl/d)				
Crude Oil Lease Gathering	676	690	695	684
LPG Sales	93	75	125	97
Refined Products	22	27	30	25
Waterborne foreign crude imported	89	75	75	82
	880	867	925	888
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.94	$ 0.75(1)	$ 0.93(1)	$ 0.89(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 is computed using the straight-line method over estimated useful lives, which range from 3 years (for office furniture and equipment) to 40 years (for certain pipelines, crude oil terminals and facilities) and includes gains and losses on the sale of assets.

4. *Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS 133).* This guidance does not include assumptions or projections with respect to potential gains or losses related to derivatives accounted for under SFAS 133, as there is no accurate way to forecast these potential gains or losses. The potential gains or losses related to these derivatives (primarily mark-to-market adjustments) could cause actual net income to differ materially from our projections, as demonstrated by the $92 million SFAS 133 mark-to-market adjustment reported for the six months ended June 30, 2008, but will reverse in future periods as the offsetting physical transactions are settled.

5. *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 may be made after the date hereof. Capital expenditures for expansion projects are forecasted to be approximately $460 million during calendar 2008, of which $256 million was spent in the first six months of 2008. Following are some of the more notable projects and forecasted expenditures for the year:

		Calendar 2008 (in millions)
Expansion Capital		
• Patoka tankage	$	46
• Paulsboro tankage		30
• Kerrobert mainline connection		21
• Fort Laramie tank expansion		22
• Pier 400[(1)]		13
• West Hynes tankage		13
• Kerrobert facility		12
• Edmonton tankage and connections		11
• Other projects, including acquisition related expansion projects [(2)]		292
		460
Maintenance Capital		70
Total Projected Capital Expenditures (excluding acquisitions)	$	530

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(1) This project requires approval from a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time. Does not include intangible expenditures of approximately $5 million for emission reduction credits.

(2) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2007 including the Salt Lake City pipeline for which estimated costs have increased approximately $50 million over the May 29, 2008 estimate, primarily due to adverse soil conditions. Such amount also includes a preliminary estimate of expansion capital projects associated with the Rainbow acquisition that are expected to be commenced in 2008.

6. *Capital Structure.* This guidance is based on our capital structure as of June 30, 2008.

7. *Interest Expense*. Debt balances are projected based on estimated cash flows, current distribution rates, forecasted 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.

   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 as part of the purchase price of crude oil.

8. *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. The following table reflects the anticipated impact of achieving our November 2008 annualized distribution goal of $3.61 to $3.66 per unit.

	Guidance (in millions)					
	Three Months Ending September 30, 2008		Three Months Ending December 31, 2008		Twelve Months Ending December 31, 2008	
	Low	High	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:						
Net Income	$ 84	$ 109	$ 106	$ 134	$ 323	$ 376
General partners incentive distribution	(34)	(34)	(35)	(37)	(126)	(128)
	4	4	6	6	18	18

General partners incentive distribution reduction		54		79		77		103		215		266
General partner 2% ownership		(1)		(2)		(2)		(2)		(4)		(5)
Net income available to limited partners	$	53	$	77	$	75	$	101	$	211	$	261
Denominator:												
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units		123		123		123		123		120		120
Effect of dilutive securities: Weighted average LTIP units		1		1		1		1		1		1
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units		124		124		124		124		121		121
Basic net income per limited partner unit	$	0.43	$	0.63	$	0.61	$	0.82	$	1.76	$	2.18
Diluted net income per limited partner unit	$	0.43	$	0.62	$	0.60	$	0.81	$	1.74	$	2.16

Net income allocated to limited partners is impacted by the income allocated to the general partner and the amount of the incentive distribution paid to the general partner. The amount of income allocated to our limited partner interests is 98% of the total partnership income after deducting the amount of the general partner s incentive distribution as adjusted for temporary reductions in the incentive distribution rights as discussed below. For the second half of 2008, our forecast incorporates the assumption that we will achieve the midpoint of our targeted distribution growth for 2008, which is based on an annualized distribution level in the fourth quarter of 2008 of $3.61 per unit to $3.66 per unit.

In conjunction with the Pacific and Rainbow acquisitions, the general partner reduced the amounts due it as incentive distributions by an aggregate amount of $75 million. Approximately $27.5 million of this reduction was realized as of May 15, 2008. Incentive distributions will be reduced by $10 million for the second half of 2008, $21 million in 2009, $11 million in 2010 and $5 million 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, respectively, net income available for limited partners by approximately $6 million ($0.05 per unit) on an annualized basis.

9. *Equity Compensation Plans*. The majority of grants outstanding under our equity compensation plans (LTIP and Class B units) 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 earliest vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of August 5, 2008, estimated vesting dates range from May 2009 to January 2016 and minimum annualized distribution levels range from $2.80 to $4.50. For some awards, a percentage of any remaining units will vest on a date certain in 2011 or 2012 and all others are forfeited.

On July 14, 2008, we declared an annualized distribution of $3.55 payable on August 14, 2008 to our unitholders of record as of August 4, 2008. In addition to the current distribution level of $3.55, we have deemed probable that the $3.75 distribution level will be achieved. Accordingly, for grants that vest at annualized distribution levels of $3.75 or less, guidance includes an accrual over the applicable service period at an assumed market price of $45.11 per unit as well as the fair value 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 date of actual vesting, (iii) the amount of amortization in the early years, (iv) the probability assessment of achieving future distribution rates, and (v) new equity compensation award grants. For example, a $3.00 change in the unit price assumption at September 30, 2008 would change the third-quarter equity compensation expense by approximately $5 million $1 million for the current quarter and $4 million for the life-to-date adjustment to the liability accrued in prior periods. Therefore, actual net income could differ materially from our projections.

Included in equity compensation expense highlighted in selected items impacting comparability for 2008 is approximately $14 million of expense attributable to the Class B units. Since the economic burden of the Class B units is borne solely by the General Partner and not the Partnership, an amount equal to the expense will be reflected as a capital contribution and thus will result in a corresponding credit to Partners Capital in the financial statements of the Partnership.

10. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the three-month guidance range ending September 30 and December 31, 2008 and twelve months ending December 31, 2008 for EBITDA and EBIT to net income.

	Guidance (in millions)					
	Three Months Ending September 30, 2008		Three Months Ending December 31, 2008		Twelve Months Ending December 31, 2008	
	Low	High	Low	High	Low	High
Reconciliation to Net Income						
EBITDA	$ 195	$ 215	$ 222	$ 247	$ 744	$ 789
Depreciation and amortization	54	52	57	56	211	208
EBIT	141	163	165	191	533	581
Interest expense	52	50	53	52	196	193
Income tax expense	5	4	6	5	14	12

Net Income	$	84	$	109	$	106	$	134	$	323	$	376

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 identified by the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and sta regarding our business strategy, plans and objectives of our management 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 are 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;
- the success of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- 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;
- 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 power 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 access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;
- 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 and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations and interpretations;
- the effects of competition;
- interruptions in service and fluctuations in tariffs or volumes 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
- 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: August 6, 2008

By: /s/ AL SWANSON

Name: Al Swanson

Title: *Senior Vice President-Finance*