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 10, 2010**

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 10, 2010.

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 2009 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 first quarter of calendar 2010 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 2010 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 9 below, we reconcile net income to EBIT and EBITDA for the 2010 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 on Segment Profit, EBITDA, Net Income attributable to Plains and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three-month period ending March 31, 2010 and twelve-month period ending December 31, 2010 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 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 9, 2010. We undertake no obligation to publicly update or revise any forward-looking statements.

On January 25, 2010, PAA announced that its wholly owned subsidiary, PAA Natural Gas Storage, L.P. ("PNGS"), had filed a registration statement on Form S-1 with the SEC relating to its proposed initial public offering of common units representing limited partner interests in PNGS. The registration statement is available on the SEC's web site at http://www.sec.gov under the registrant's name, "PAA Natural Gas Storage, L.P.," but has not yet become effective. Although PAA is an existing issuer, PNGS is not. Under these circumstances, SEC rules restrict the disclosure of certain types of information about a potential issuer. In respect of these restrictions, we have modified the format and level of detail we typically apply to certain aspects of our presentation as they relate to specific information regarding PNGS activities. The PNGS securities may not be sold nor may offers to buy be accepted prior to the time the registration statement becomes effective. This notice shall not constitute an offer to sell or a solicitation of an offer to buy, nor shall there be any sale of these securities in any state or jurisdiction in which such an offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such state or jurisdiction.

Plains All American Pipeline, L.P.
Operating and Financial Guidance
(in millions, except per unit data)

	Guidance [1]			
	3 Months Ending March 31, 2010		12 Months Ending December 31, 2010	
	Low	High	Low	High
Total Segment Profit				
Net revenues (including equity earnings from unconsolidated entities)	$ 472	$ 487	$ 1,895	$ 1,930
Field operating costs	(176)	(173)	(702)	(693)
General and administrative expenses	(57)	(55)	(212)	(206)
	239	259	981	1,031
Depreciation and amortization expense	(65)	(63)	(257)	(251)
Interest expense, net	(61)	(59)	(246)	(238)
Income tax expense	(2)	(1)	(5)	(3)
Other income (expense), net	(1)	(1)	(2)	(2)
Net Income	**$ 110**	**$ 135**	**$ 471**	**$ 537**
Less: Net income attributable to the noncontrolling interest	—	—	(2)	(2)
Net Income attributable to Plains	**$ 110**	**$ 135**	**$ 469**	**$ 535**
Net Income Attributable to Plains—Limited Partners	$ 72	$ 96	$ 309	$ 373
Basic Net Income Per Limited Partner Unit				
Weighted Average Units Outstanding	136	136	136	136
Net Income Per Unit	$ 0.52	$ 0.70	$ 2.25	$ 2.72
Diluted Net Income Per Limited Partner Unit				
Weighted Average Units Outstanding	137	137	137	137
Net Income Per Unit	$ 0.51	$ 0.69	$ 2.23	$ 2.71
EBIT	**$ 173**	**$ 195**	**$ 722**	**$ 778**
EBITDA	**$ 238**	**$ 258**	**$ 979**	**$ 1,029**
Selected Item Impacting Comparability				
Equity compensation charge	$ (12)	$ (12)	$ (36)	$ (36)
Excluding Selected Items Impacting Comparability				
Adjusted Segment Profit				
Transportation	$ 120	$ 124	$ 516	$ 528
Facilities	59	61	266	272
Supply and Logistics	72	86	235	267
Other Income (Expense), net	(1)	(1)	(2)	(2)
Adjusted EBITDA	$ 250	$ 270	$ 1,015	$ 1,065
Adjusted Net Income attributable to Plains	$ 122	$ 147	$ 505	$ 571
Adjusted Basic Net Income per Limited Partner Unit	$ 0.60	$ 0.78	$ 2.50	$ 2.98
Adjusted Diluted Net Income per Limited Partner Unit	$ 0.60	$ 0.78	$ 2.49	$ 2.96

[1] The projected average foreign exchange rate is $1.10 Canadian dollar to $1 U.S. Dollar. The rate as of February 9, 2010 was $1.07 Canadian dollar to $1 U.S. Dollar. A $0.10 change in the FX rate will impact annual EBITDA by approximately $13 million.

Notes and Significant Assumptions:

1. *Definitions.*

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Adjusted Segment Profit	Net revenues (including equity earnings, as applicable) less field operating costs and segment general and administrative expenses as adjusted for selected items impacting comparability as itemized in the Operating and Financial Guidance table on page 3
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.
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) Supply and Logistics. We previously referred to the Supply and Logistics segment as the Marketing segment. We revised the segment name to better describe the business activities conducted within that segment. 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 and Frontier pipeline systems and Settoon Towing, in which we own noncontrolling interests.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Actual volumes are influenced by maintenance schedules at refineries, production declines, weather and other natural disasters including hurricanes, changes in the quantity of inventory held in tanks, and other external factors beyond our control. Adjusted 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 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.

	2010 Guidance	
	Three Months Ending March 31,	**Twelve Months Ending December 31,**
Average Daily Volumes (000 Bbls/d)		
All American	41	41
Basin	320	360
Capline	235	190
Line 63 / 2000	130	130
Salt Lake City Area Systems [1]	120	135
West Texas / New Mexico Area Systems [1]	370	375
Rainbow	190	190
Manito	60	60
Rangeland	50	50
Refined Products	120	120
Other	1,204	1,184
	2,840	2,835
Trucking	80	80
	2,920	2,915
Adjusted Segment Profit per Barrel ($/Bbl)	$ 0.46[2]	$ 0.49[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, 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.

2010 Guidance

	Three Months Ending March 31,	Twelve Months Ending December 31,
Facilities Total Operating Activities [1]		
Avg. Capacity (MMBbls/Mo.)	64	68
Adjusted Segment Profit per Barrel ($/Bbl)	$ 0.31[2]	$ 0.33[2]

[1] 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.

[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, 2010 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 actual segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	2010 Guidance	
	Three Months Ending March 31,	Twelve Months Ending December 31,
Average Daily Volumes (MBbl/d)		
Crude Oil Lease Gathering Purchases	595	595
LPG Sales	170	130
Refined Products Sales	35	45
Waterborne foreign crude oil imported	55	55
	855	825
Adjusted Segment Profit per Barrel ($/Bbl)	$ 1.03[1]	$ 0.83[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, or asset impairments.

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 2010 to be approximately $360 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, 2010 (in millions):

Expansion Capital	
· Patoka Phase III	$ 24
· West Texas gathering lines	18
· Bumstead facility upgrade	17
· Cushing - Phase VII	17
· St. James - Phase III	15
· Cushing - Phase VIII	15

· Wichita Falls tanks	11
· Martinez tanks	9
· Other projects, including acquisition related expansion projects [1]	234
	360
Maintenance Capital	85
Total Projected Capital Expenditures (excluding acquisitions)	$ 445

[1] Primarily gas storage construction projects, pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2009.

5. *Capital Structure.* This guidance is based on our capital structure as of December 31, 2009.

6. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, and 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, amortization of 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. *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 (in millions, except per unit data)			
	3 Months Ending March 31, 2010		12 Months Ending December 31, 2010	
	Low	**High**	**Low**	**High**
Numerator for basic and diluted earnings per limited partner unit:				
Net Income attributable to Plains	$ 110	$ 135	$ 469	$ 535
Less: General partner's incentive distribution paid[1]	(37)	(37)	(154)	(154)
Subtotal	73	98	315	381
Less: General partner 2% ownership [1]	(1)	(2)	(6)	(8)
Net income available to limited partners	72	96	309	373
Adjustment in accordance with application of the two-class method for MLPs [1]	(2)	(1)	(3)	(2)
Net income available to limited partners in accordance with application of the two-class method for MLPs [1]	$ 70	$ 95	$ 306	$ 371
Denominator:				
Basic weighted average number of limited partner units outstanding	136	136	136	136
Effect of dilutive securities:				
Weighted average LTIP units	1	1	1	1
Diluted weighted average number of limited partner units outstanding	137	137	137	137
Basic net income per limited partner unit	$ 0.52	$ 0.70	$ 2.25	$ 2.72
Diluted net income per limited partner unit	$ 0.51	$ 0.69	$ 2.23	$ 2.71

[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 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 the Pacific, Rainbow and PNGS acquisitions, our general partner reduced the amounts due it as incentive distributions by an aggregate amount of $83 million. Approximately $60 million of this reduction was realized as of December 31, 2009. Incentive distributions will be reduced approximately $16 million in 2010 and $7 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 net income available for limited partners by approximately $7 million ($0.05 per unit) on an annualized basis.

8. *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 February 10, 2010, estimated vesting dates range from May 2010 to May 2019 and annualized distribution levels range from $3.00 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 are forfeited.

On January 20, 2010, we declared an annualized distribution of $3.71 payable on February 12, 2010 to our unitholders of record as of February 2, 2010. We have made the assessment that a $3.90 distribution level is probable of occurring prior to the expiration dates of the underlying LTIP grants and accordingly, for grants that vest at annualized distribution levels of $3.90 or less, guidance includes an accrual over the applicable service period at an assumed market price of approximately $53.00 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 the 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 March 31, 2010 would change the first-quarter equity compensation expense by approximately $6 million. Therefore, actual net income could differ materially from our projections.

9. *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 ranges ending March 31, 2010 and December 31, 2010, respectively.

	3 Months Ending March 31, 2010		12 Months Ending December 31, 2010	
	Low	High	Low	High
Reconciliation to EBITDA				
Net Income	$ 110	$ 135	$ 471	$ 537
Interest expense	(61)	(59)	(246)	(238)
Income tax expense	(2)	(1)	(5)	(3)
EBIT	173	195	722	778
Depreciation and amortization	(65)	(63)	(257)	(251)
EBITDA	$ 238	$ 258	$ 979	$ 1,029

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 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 the 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 success 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 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 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 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 the amplification of other risks caused by deteriorated 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: February 10, 2010

By: /s/ AL SWANSON
Name: Al Swanson
Title: *Senior Vice President and Chief Financial Officer*

Contacts: **Roy I. Lamoreaux**
Director, Investor Relations
713/646-4222 – 800/564-3036

Al Swanson
Senior Vice President, CFO
713/646-4455 – 800/564-3036

FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P. Reports
Solid Fourth-Quarter and Full-Year 2009 Results

(Houston — February 10, 2010) Plains All American Pipeline, L.P. (NYSE: PAA) today reported net income attributable to Plains of $110 million, or $0.52 per diluted limited partner unit, for the fourth quarter 2009 and net income attributable to Plains of $579 million, or $3.32 per diluted limited partner unit, for the full year 2009. Net income attributable to Plains for the fourth quarter 2008 was $98 million, or $0.56 per diluted limited partner unit, and net income attributable to Plains for the full year 2008 was $437 million, or $2.64 per diluted limited partner unit.

The Partnership reported earnings before interest, taxes, depreciation and amortization ("EBITDA") of $236 million and $1.05 billion for the respective fourth-quarter and full-year 2009 periods, compared with reported EBITDA for the comparable 2008 periods of $213 million and $852 million. (See the section of this release entitled "Non-GAAP Financial Measures" and the attached tables for discussion of EBITDA and other non-GAAP financial measures, and reconciliations of such measures to the comparable GAAP measures.)

"2009 represents another year of solid execution for the Partnership and marks eight consecutive years of delivering performance in line with guidance," stated Greg L. Armstrong, Chairman and CEO of Plains All American. "These solid results, generated during a period of significant volatility in the energy markets, further reinforce the durability and predictability of PAA's baseline cash flow and are indicative of the positive transformation that PAA has undertaken over the past several years towards a lower risk profile."

Armstrong continued, "In addition to delivering operating and financial performance in line with guidance, throughout 2009 we invested approximately $760 million in organic growth projects and acquisitions, increased the distributions we paid by 3.6%, and generated aggregate annual distribution coverage of 114%. We ended the year with a solid balance sheet and approximately $975 million of committed liquidity. As we look forward to 2010 and beyond, we are well positioned to continue to grow our business platforms and distributable cash flow through a combination of our organic growth capital projects and acquisitions."

The Partnership's reported results include the impact of items that affect comparability between reporting periods. These items are excluded from adjusted results, as further described in the table below. Accordingly, the Partnership's fourth-quarter 2009 adjusted net income attributable to Plains, adjusted net income per diluted limited partner unit and adjusted EBITDA were $149 million, $0.80 and $275

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million, respectively, as compared to fourth-quarter 2008 adjusted net income attributable to Plains, adjusted net income per diluted limited partner unit and adjusted EBITDA of $121 million, $0.74 and $236 million, respectively.

The Partnership's adjusted net income attributable to Plains, adjusted net income per diluted limited partner unit and adjusted EBITDA for the full year 2009 were $555 million, $3.14 and $1.02 billion, respectively, as compared to adjusted net income attributable to Plains, adjusted net income per diluted limited partner unit and adjusted EBITDA for the full year 2008 of $472 million, $2.93 and $887 million, respectively.

The following table summarizes selected items that the Partnership believes impact comparability of financial results between reporting periods (amounts in millions, except per unit amounts):

	Three Months Ended December 31,		**Twelve Months Ended December 31,**	
	2009	**2008**	**2009**	**2008**
	(In millions, except per unit data)			
Selected Items Impacting Comparability - Income / (Loss):				
Equity compensation benefit/(charge) [1]	$ (14)	$ 2	$ (50)	$ (21)
Inventory valuation adjustments net of gains/(losses) from related derivative activities [2]	—	(16)	24	(11)
Gains/(losses) from other derivative activities [2] [3]	(20)	4	34	7
Net loss on early repayment of 7.125% $250 million senior notes	(4)	—	(4)	—
PNGS contingent consideration fair value adjustment	(1)	—	(1)	—
Net gain on purchase of remaining 50% interest in PNGS	—	—	9	—
Net gain/(loss) on foreign currency revaluation	—	(13)	12	(21)

Gains on acquisition-related foreign currency and linefill hedges	—	—	—	11
Selected items impacting comparability	(39)	(23)	24	(35)
Less: GP 2% portion of selected items impacting comparability	1	—	—	1
LP 98% portion of selected items impacting comparability	$ (38)	$ (23)	$ 24	$ (34)
Impact to basic net income per limited partner unit	$ (0.28)	$ (0.19)	$ 0.18	$ (0.29)
Impact to diluted net income per limited partner unit	$ (0.28)	$ (0.18)	$ 0.18	$ (0.29)

(1) The equity compensation benefits and charges for the three and twelve months ended December 31, 2009 and 2008 exclude the portion of the equity compensation expense represented by grants under the LTIP Plans that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans is approximately $6 million and less than $1 million for the three months ended December 31, 2009 and 2008, respectively, and approximately $18 million and $3 million for the twelve months ended December 31, 2009 and 2008, respectively.

(2) Gains and losses from derivative activities related to revalued inventory are included in the line item "Inventory valuation adjustments net of (gains)/losses from related derivative activities;" gains and losses from derivative activities not related to revalued inventory are included in the line item "Gains/(losses) from other derivative activities."

(3) Gains and losses from other derivative activities for the three and twelve months ended December 31, 2009 includes losses of approximately $2 million and $4 million, respectively, related to interest rate derivatives, which are included in other income/(expense), net, but do not impact segment profit. Gains and losses from other derivative activities for both the three and twelve months ended December 31, 2008 include gains of approximately $3 million related to interest rate derivatives, which are included in other income/(expense), net, but do not impact segment profit.

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The following tables present certain selected financial information by segment for the fourth-quarter and full-year reporting periods (amounts in millions):

	Three Months Ended December 31, 2009			Three Months Ended December 31, 2008		
	Transportation	Facilities	Supply & Logistics [1]	Transportation	Facilities	Supply & Logistics [1]
Revenues [2]	$ 248	$ 103	$ 5,881	$ 246	$ 77	$ 4,755
Purchases and related costs [2]	(16)	(4)	(5,752)	(21)	—	(4,663)
Field operating costs (excluding equity compensation charge) [2]	(84)	(35)	(43)	(85)	(28)	(47)
Equity compensation charge - operations	(3)	—	(1)	—	—	—
Segment G&A expenses (excluding equity compensation benefit/(charge)) [3]	(17)	(8)	(17)	(13)	(5)	(15)
Equity compensation benefit/(charge) - general and administrative	(7)	(3)	(6)	1	—	1
Equity earnings in unconsolidated entities	2	—	—	2	2	—
Reported segment profit	$ 123	$ 53	$ 62	$ 130	$ 46	$ 31
Selected items impacting comparability of segment profit:						
Equity compensation (benefit)/charge [4]	7	3	4	(1)	—	(1)
Inventory valuation adjustments net of (gains)/losses from related derivative activities [5]	—	—	—	—	—	16
(Gains)/losses from other derivative activities [5] [6]	—	—	18	—	—	(1)
Net loss on foreign currency revaluation	—	—	—	—	—	13
Subtotal	7	3	22	(1)	—	27
Segment profit excluding selected items impacting comparability	$ 130	$ 56	$ 84	$ 129	$ 46	$ 58
Maintenance capital	$ 17	$ 5	$ 3	$ 16	$ 8	$ 1

	Twelve Months Ended December 31, 2009			Twelve Months Ended December 31, 2008		
	Transportation	Facilities	Supply & Logistics [1]	Transportation	Facilities	Supply & Logistics [1]
Revenues [2]	$ 961	$ 362	$ 17,759	$ 927	$ 270	$ 29,350
Purchases and related costs [2]	(63)	(5)	(17,141)	(88)	—	(28,873)
Field operating costs (excluding equity compensation charge) [2]	(333)	(120)	(183)	(331)	(104)	(185)
Equity compensation charge - operations	(9)	(1)	(1)	(1)	—	—
Segment G&A expenses (excluding equity compensation charge) [3]	(61)	(26)	(67)	(56)	(18)	(63)

Equity compensation charge - general and administrative	(25)	(10)	(22)	(11)	(4)	(8)
Equity earnings in unconsolidated entities	7	8	—	5	9	—
Reported segment profit	$ 477	$ 208	$ 345	$ 445	$ 153	$ 221
Selected items impacting comparability of segment profit:						
Equity compensation charge [4]	25	9	16	11	3	7
Inventory valuation adjustments net of (gains)/losses from related derivative activities [5]	—	—	(24)	—	—	11
(Gains)/losses from other derivative activities [5] [6]	—	—	(38)	—	—	(4)
Net (gain)/loss on foreign currency revaluation	—	—	(12)	—	—	21
Subtotal	25	9	(58)	11	3	35
Segment profit excluding selected items impacting comparability	$ 502	$ 217	$ 287	$ 456	$ 156	$ 256
Maintenance capital	$ 57	$ 16	$ 8	$ 54	$ 23	$ 4

(1) We previously referred to the Supply and Logistics segment as the Marketing segment. We revised the segment name to better describe the business activities conducted within that segment.

(2) Includes intersegment amounts.

(3) Segment general and administrative expenses (G&A) reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(4) The equity compensation benefits and charges for the three and twelve months ended December 31, 2009 and 2008 exclude the portion of the equity compensation expense represented by grants under the LTIP Plans that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans is approximately $6 million and less than $1 million for the three months ended December 31, 2009 and 2008, respectively, and approximately $18 million and $3 million for the twelve months ended December 31, 2009 and 2008, respectively.

(5) Gains and losses from derivative activities related to revalued inventory are included in the line item “Inventory valuation adjustments net of (gains)/losses from related derivative activities;” gains and losses from derivative activities not related to revalued inventory are included in the line item “Gains/(losses) from other derivative activities.”

(6) Gains and losses from other derivative activities for the three and twelve months ended December 31, 2009 includes losses of approximately $2 million and $4 million, respectively, related to interest rate derivatives, which are included in other income/(expense), net, but do not impact segment profit. Gains and losses from other derivative activities for both the three and twelve months ended December 31, 2008 include gains of approximately $3 million related to interest rate derivatives, which are included in other income/(expense), net, but do not impact segment profit.

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Adjusted segment profit for the Transportation segment for the fourth quarter and full year of 2009 increased 1% and 10%, respectively, over corresponding 2008 results. The fourth-quarter increase reflects the benefit of increased tariff rates partially offset by lower volumes. The full-year increase primarily reflects higher average tariff rates and increased pipeline loss allowance revenue, partially offset by a gain on sale of linefill during the 2008 period.

Adjusted segment profit for the Facilities segment for the fourth quarter and full year of 2009 increased 22% and 39%, respectively, over comparable 2008 metrics primarily due to capacity increases from recently completed capital projects and acquisitions.

Adjusted segment profit for the Supply & Logistics segment for the fourth quarter and full year of 2009 increased 45% and 12% over comparable 2008 metrics. The increase in the fourth-quarter results over the prior period resulted primarily from higher average LPG margins, partially offset by lower quality arbitrage opportunities resulting from tighter crude oil differentials. The increase in the full-year 2009 results over the prior period resulted primarily from higher LPG margins and favorable contango market conditions experienced early in the year, partially offset by lower gathering margins.

The Partnership’s basic weighted average units outstanding for the fourth quarter of 2009 totaled 136 million (137 million diluted) as compared to 123 million (124 million diluted) in last year’s fourth quarter. At December 31, 2009, the Partnership had approximately 136.1 million units outstanding, long-term debt of approximately $4.1 billion ($222 million of which supports hedged inventory) and an adjusted long-term debt-to-total capitalization ratio of 49%.

The Partnership has declared a quarterly distribution of $0.9275 per unit ($3.71 per unit on an annualized basis) payable February 12, 2010 on its outstanding limited partner units. This distribution represents an increase of approximately 3.9% over the quarterly distribution paid in February 2009 and an increase of approximately 0.8% from the November 2009 distribution level.

Prior to its February 11th conference call, the Partnership will furnish a current report on Form 8-K, which will include material in this press release and financial and operational guidance for the first quarter and full year 2010. A copy of the Form 8-K will be available on the Partnership’s website at www.paalp.com.

Non-GAAP Financial Measures

In this release, the Partnership's EBITDA disclosure is not presented in accordance with generally accepted accounting principles and is not intended to be used in lieu of GAAP presentations of net income or cash flows from operating activities. EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as 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 present selected items that impact the comparability of our operating results as additional information that may be helpful to your understanding of our financial results. We consider an understanding of these selected items impacting comparability to be material to our evaluation of our operating results and prospects.

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Although we present selected items that we consider in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions and numerous other factors. These types of variations are not separately identified in this release, but will be discussed, as applicable, in management's discussion and analysis of operating results in our Annual Report on Form 10-K.

A reconciliation of EBITDA to net income and cash flows from operating activities for the periods presented is included in the tables attached to this release. In addition, the Partnership maintains on its website (www.paalp.com) a reconciliation of all non-GAAP financial information, such as EBITDA, to the most comparable GAAP measures. To access the information, investors should click on the "Investor Relations" link on the Partnership's home page and then the "Non-GAAP Reconciliation" link on the Investor Relations page.

Conference Call

The Partnership will host a conference call at 11:00 AM (Eastern) on Thursday, February 11, 2010 to discuss the following items:

1. The Partnership's fourth-quarter and full-year 2009 performance;
2. The status of major expansion projects;
3. Capitalization and liquidity;
4. Financial and operating guidance for the first quarter and full year 2010; and
5. The Partnership's outlook for the future.

Webcast Instructions

To access the Internet webcast, please go to the Partnership's website at www.paalp.com, choose "Investor Relations," and then choose "Conference Calls." Following the live webcast, the call will be archived for a period of sixty (60) days on the Partnership's website.

If you are unable to participate in the webcast, please dial 800-230-1059, or, for international callers, 612-234-9960, at approximately 10:55 AM (Eastern). No password is required. You may access the slide presentation accompanying the conference call a few minutes prior to the call under the Conference Call Summaries portion of the Conference Calls tab of the Investor Relations section of PAA's website at www.paalp.com.

Telephonic Replay Instructions

To listen to a telephonic replay of the conference call, please dial 800-475-6701, or, for international callers, 320-365-3844, and replay access code 141692. The replay will be available beginning Thursday, February 11, 2010, at approximately 12:00 PM (Central) and continue until 10:59 PM (Central) Thursday, March 11, 2010.

Plains All American Pipeline, L.P. is a publicly traded master limited partnership engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied

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petroleum gas and other natural gas related petroleum products. The Partnership is also engaged in the development and operation of natural gas storage facilities. The Partnership is headquartered in Houston, Texas.

Forward Looking Statements

Except for the historical information contained herein, the matters discussed in this release are forward-looking statements that involve certain risks and uncertainties that could cause actual results to differ materially from results anticipated in the forward-looking statements. These risks and uncertainties include, among other things, 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 success 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 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 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 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 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 the amplification of other risks caused by deteriorated 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 discussed in the Partnership’s filings with the Securities and Exchange Commission.

333 Clay Street, Suite 1600 Houston, Texas 77002 713-646-4100 / 800-564-3036

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per unit data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2009	2008	2009	2008
REVENUES	$ 6,078	$ 4,943	$ 18,520	$ 30,061
COSTS AND EXPENSES				
Purchases and related costs	5,620	4,550	16,656	28,479
Field operating costs	164	159	638	617
General and administrative expenses	58	31	211	160
Depreciation and amortization	63	61	236	211
Total costs and expenses	5,905	4,801	17,741	29,467
OPERATING INCOME	173	142	779	594
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	2	4	15	14
Interest expense	(58)	(53)	(224)	(196)
Other income/(expense), net	(2)	6	16	33
INCOME BEFORE TAX	115	99	586	445
Current income tax expense	(10)	—	(15)	(9)
Deferred income tax benefit/(expense)	5	(1)	9	1
NET INCOME	110	98	580	437
Less: Net income attributable to the noncontrolling interest	—	—	(1)	—
NET INCOME ATTRIBUTABLE TO PLAINS	$ 110	$ 98	$ 579	$ 437
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 74	$ 69	$ 443	$ 325
GENERAL PARTNER	$ 36	$ 29	$ 136	$ 112
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.53	$ 0.56	$ 3.34	$ 2.66
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.52	$ 0.56	$ 3.32	$ 2.64
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	136	123	130	120

DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	137	124	131	121

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

OPERATING DATA [(1)]

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2009	**2008**	**2009**	**2008**
Transportation activities (Average Daily Volumes, thousands of barrels):				
Tariff activities				
All American	41	45	40	45
Basin	407	394	394	377
Capline	160	222	193	219
Line 63/Line 2000	117	135	131	147
Salt Lake City Area Systems [(2)]	129	88	131	93
West Texas/New Mexico Area Systems [(2)]	349	386	368	372
Manito	65	71	63	70
Rainbow	180	192	183	129
Rangeland	48	58	53	58
Refined products	110	105	100	109
Other	1,101	1,233	1,180	1,232
Tariff activities total	2,707	2,929	2,836	2,851
Trucking	87	101	85	97
Transportation activities total	2,794	3,030	2,921	2,948
Facilities activities (Average Monthly Volumes):				
Crude oil, refined products, and LPG storage (average monthly capacity in millions of barrels)	57	55	56	53
Natural gas storage (average monthly capacity in billions of cubic feet) [(3)]	40	16	26	14
LPG processing (average throughput in thousands of barrels per day)	14	17	15	17
Facilities activities total (average monthly capacity in millions of barrels) [(4)]	64	58	61	56
Supply & Logistics activities (Average Daily Volumes, thousands of barrels):				
Crude oil lease gathering purchases	594	645	612	658
Refined products	37	33	35	26
LPG sales	154	157	105	103
Waterborne foreign crude oil imported	59	66	55	80
Supply & Logistics activities total	844	901	807	867

(1) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

(2) The aggregate of multiple systems in the respective areas.

(3) In September 2009, we acquired the remaining 50% indirect interest in PAA Natural Gas Storage, LLC (“PNGS”) from Vulcan Gas Storage LLC, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for 2008 and January through August 2009 are netted to our 50% interest in PNGS. September 2009 through December 2009 volumes represent our 100% interest in PNGS.

(4) Facilities total is 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 crude oil barrel 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.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(In millions)

	December 31, 2009	December 31, 2008
ASSETS		
Current assets	$ 3,658	$ 2,596
Property and equipment, net	6,340	5,059
Linefill and base gas	501	425
Long-term inventory	121	139
Investment in unconsolidated entities	82	257
Goodwill	1,287	1,210
Other long-term assets, net	369	346
Total assets	$ 12,358	$ 10,032
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 3,782	$ 2,960
Long-term debt under credit facilities and other	6	40
Senior notes, net of unamortized net discount	4,136	3,219
Other long-term liabilities and net deferred credits	275	261
Total liabilities	8,199	6,480
Partners' capital excluding noncontrolling interest	4,096	3,552
Noncontrolling interest	63	—
Total partners' capital	4,159	3,552
Total liabilities and partners' capital	$ 12,358	$ 10,032

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CREDIT RATIOS
(In millions)

	December 31, 2009	Adjustment [1]	December 31, 2009 Adjusted
Short-term debt	$ 1,074	$ 222	$ 1,296
Long-term debt	4,142	(222)	3,920
Total debt	$ 5,216	$ —	$ 5,216
Long-term debt	$ 4,142	$ (222)	$ 3,920
Partners' Capital	4,159	—	4,159
Total book capitalization	$ 8,301	$ (222)	$ 8,079
Total book capitalization including short-term debt	$ 9,375	$ —	$ 9,375
Long-term debt to total book capitalization	50%		49%
Total debt to total book capitalization including short-term debt	56%		56%

(1) The adjustment represents the portion of the 4.25% senior notes due September 2012 that has been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities. These notes were issued in July 2009 and the proceeds are being used to supplement capital available from our hedged inventory facility.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED EARNINGS PER LIMITED PARTNER UNIT
(In millions, except per unit data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2009	2008	2009	2008
Numerator for basic and diluted earnings per limited partner unit:				
Net Income Attributable to Plains	$ 110	$ 98	$ 579	$ 437
Less: General partner's incentive distribution paid [1]	(35)	(28)	(127)	(106)
Subtotal	75	70	452	331
Less: General partner 2% ownership [1]	(1)	(1)	(9)	(6)
Net income available to limited partners	74	69	443	325
Adjustment in accordance with application of the two-class method for MLPs [1]	(2)	—	(9)	(5)
Net income available to limited partners in accordance with application of the two-class method for MLPs [1]	$ 72	$ 69	$ 434	$ 320
Denominator:				
Basic weighted average number of limited partner units outstanding	136	123	130	120
Effect of dilutive securities:				
Weighted average LTIP units	1	1	1	1
Diluted weighted average number of limited partner units outstanding	137	124	131	121
Basic net income per limited partner unit	$ 0.53	$ 0.56	$ 3.34	$ 2.66
Diluted net income per limited partner unit	$ 0.52	$ 0.56	$ 3.32	$ 2.64

[1] We calculate net income available to limited partners 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 in the earnings per unit calculation. After adjusting for this distribution, the remaining undistributed earnings or excess distributions 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."

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS
(In millions)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2009	2008	2009	2008
Net income to earnings before interest, taxes, depreciation and amortization ("EBITDA") and excluding selected items impacting comparability ("Adjusted EBITDA") reconciliations				
Net Income	$ 110	$ 98	$ 580	$ 437
Add: Interest expense	58	53	224	196
Add: Income tax expense	5	1	6	8
Add: Depreciation and amortization	63	61	236	211
EBITDA	236	213	1,046	852
Selected items impacting comparability	39	23	(24)	35
Adjusted EBITDA	$ 275	$ 236	$ 1,022	$ 887

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2009	2008	2009	2008
Cash flow from operating activities reconciliation				

	2009 (3M)	2008 (3M)	2009 (12M)	2008 (12M)
EBITDA	$ 236	$ 213	$ 1,046	$ 852
Current income tax expense	(10)	—	(15)	(9)
Interest expense	(58)	(53)	(224)	(196)
Net change in assets and liabilities, net of acquisitions	(170)	458	(510)	186
Other items to reconcile to cash flows from operating activities:				
Equity compensation (benefit)/charge	20	(2)	68	24
Net cash provided by operating activities	$ 18	$ 616	$ 365	$ 857

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS
(In millions, except per unit data) (continued)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2009	2008	2009	2008
Funds flow from operations (“FFO”)/Distributable cash flow (“DCF”)				
Net Income	$ 110	$ 98	$ 580	$ 437
Equity earnings in unconsolidated entities, net of distributions	(2)	(1)	(8)	(4)
Depreciation and amortization	63	61	236	211
Deferred income tax (benefit)/expense	(5)	1	(9)	(1)
Distribution to noncontrolling interest	(2)	—	(2)	—
FFO	164	159	797	643
Maintenance capital	(25)	(25)	(81)	(81)
FFO after maintenance capital	139	134	716	562
Selected items impacting comparability	39	23	(24)	35
DCF	$ 178	$ 157	$ 692	$ 597

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2009	2008	2009	2008
Net income Attributable to Plains and earnings per limited partner unit excluding selected items impacting comparability				
Net Income Attributable to Plains	$ 110	$ 98	$ 579	$ 437
Selected items impacting comparability	39	23	(24)	35
Adjusted Net Income Attributable to Plains	$ 149	$ 121	$ 555	$ 472
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 72	$ 69	$ 434	$ 320
Limited partners’ 98% of selected items impacting comparability	38	23	(24)	34
Adjusted limited partners’ net income	$ 110	$ 92	$ 410	$ 354
Adjusted basic net income per limited partner unit	$ 0.81	$ 0.75	$ 3.16	$ 2.96
Adjusted diluted net income per limited partner unit	$ 0.80	$ 0.74	$ 3.14	$ 2.93
Basic weighted average units outstanding	136	123	130	120
Diluted weighted average units outstanding	137	124	131	121

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